
# ONTARIO ENERGY BOARD

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| **FILE NO.:** | **EB-2017-0049** | **Hydro One Networks Inc.** |

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| **VOLUME:** | **Volume 9** | |
| **DATE:** | **June 25, 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 25, 2018,
commencing at 9:09 a.m.

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VOLUME 9

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BEFORE:

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

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

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

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

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

ALSO PRESENT:

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| JODY McEACHRAN | Hydro One Networks Inc. |

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

# E X H I B I T S

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

Monday, June 25, 2018

--- On commencing at 9:09 a.m.

MR. QUESNELLE: Good morning, Mr. Nettleton. Any preliminary matters for yourself?

MR. NETTLETON: Good morning, Mr. Chairman, Panel members. We have no preliminary matters, but I do believe my friend Mr. Rubenstein does.

MR. QUESNELLE: Okay, Mr. Rubenstein?

**PRELIMINARY MATTERS:**

MR. RUBENSTEIN: Good morning, Panel. This is with respect to Undertaking J7.1. Can you hear me? Good morning. This is with respect to Undertaking J7.1. This was, if you recall, the Boston Consulting presentation undertaking, and my friends filed it on Friday afternoon, and in doing so, it filed -- it made two sets of redactions, I think it is just in generally with the discussion that we had on Friday. It redacted in black areas that were outside the scope of the proceeding, so transmission or unregulated or otherwise, and then in red, material that in its view was confidential because, in reading from the covering letter accompanying -- or not the covering letter but the text of the undertaking response, that it believed related to sensitive commercial information related to third-party contract negotiations that have not publicly disclosed -- or staffing matters impacting unionized employees that have not been publicly disclosed.

There is a very significant amount of red redactions

that I submit, first, it's unclear the nature of them. In many cases it's just simply pages, the full amounts, that are redacted in red, but putting that aside, I'm unclear, and I'd ask for the Board's guidance, what the Board's intentions would be. We would submit that at the very least the information should be provided on a confidential basis to those parties that have signed the declaration and undertaking.

It's my understanding that my friend's intention is not to so, just to leave it as is and keep the amounts redacted. I think they're clearly -- the information is clearly relevant to aspects of this application. They relate -- there are plenty -- there are -- I mean, I'm not sure if the undertaking could be brought up on the screen so -- if this may be helpful to the Board. I'm not sure if it's had a chance to review the undertaking yet.

MR. QUESNELLE: We just received it literally minutes ago, so, no, we haven't reviewed it.

MR. RUBENSTEIN: So I can just -- if we can just put it up on the screen and walk through maybe a couple of examples, and I'll leave it to the Panel if it wants to review it in full later.

Can J7.1 be brought up, please? So if we can go to an attachment 1, page 52, 51, 52. So on this page, this is with respect to -- this is just one small example with respect to potential application -- this is again a presentation, I believe, from early 2016, so this is redacted specific, I believe, elements that could be

meeting this optimized with respect to the fleet.

If we could just go to the next page, which further redactions -- the next page we see it again with facilities management. If we can go to attachment 2, page 48, I'll just -- just as another example...

We see under the executive summary "organizational effectiveness", and then for the next six pages it is entirely redacted. So I obviously can't speak to the contents, and if it meets the Board's guidelines of confidentiality, but I would say at the very least this information is clearly relevant. I think my friends recognize by putting it in the red that it falls within the scope of the proceeding, and I'd ask at the very least that those who signed the declaration undertaking can have the ability to review this material.

MR. QUESNELLE: Thank you. Mr. Nettleton?

MR. NETTLETON: Well, Mr. Chairman, let me just explain, sir, the effort that has gone into obtaining this information. You can see that there are over 400 pages of presentation material. If we go to the explanatory, which is the first page of the undertaking, and I'll wait for it to come up, I would encourage and impress upon the Board the need to carefully read the language setting out what it is that this 400 pages of material relates to.

It concerns a series of meetings of the steering committee, known as the "Good to Great Initiative", that all fed into the board of director presentation that we did file on an unredacted basis that went to the board of

directors.

The text of this explanatory goes out of its way to impress upon the reader that these are working drafts, that this is all material that was used by the steering committee and by the Good to Great Initiative for purposes of preparing the work product that went to the board of directors.

Mr. Rubenstein is overstating the belief that this is clearly relevant to this proceeding. The series of meetings that took place took place were over a year before this application was filed. It related again to an internal initiative arising out of the going-public transaction to find and make organizational changes to Hydro One.

So if we, for example, go to the second page, you can see that this was the first meeting held on February 9th, 2016. And if we go to the next page -- sorry, keep going -- here is the typical agenda that you will see for each and every one of the meetings where there were presentations delivered.

And you can see that with each meeting there were presenters that came into the committee, gave their submissions. There was obviously discussions held regarding what the presentation was intended for, and that interaction, of course, would not have been captured in a PowerPoint presentation. It was clearly intended for dialogue, internal dialogue.

If we start going down the path, Mr. Chairman, of

starting to look at individual conversations and individual dialogues and only capture part of the process, namely a presentation, and suggest that that has some relevance to an application that is then filed over a year later, I really question what weight, what reliability, what relevance it has to the application that's before this Board.

MR. QUESNELLE: Mr. Nettleton, I think this might be as simple as the Board -- or the -- your client's protocol that attached to this, that is redacted in black, it is not relevant, if it is redacted in red it is commercially sensitive, or other matters, so I think Mr. Rubenstein's question is: If it's not redacted in black, then it's relevant. Why wouldn't you just apply the Board's usual protocol of confidentiality and allow those who have signed a declaration to see it?

MR. NETTLETON: Again, we have not said it's relevant. We've said that the redactions in red relate to commercially sensitive information of the company.

The relevance that we say applies to this hearing relates to the application that has been filed before the Board. If there are numbers, for example, in the red that relate to, I think Mr. Rubenstein put up "fleet management", that happened in February 2016, and those numbers differ from what has been applied for in this case, we are now going to have a conversation of what was in your mind in 2016 when you made a presentation to steering committee and what were the exchanges that took place, and

the problem, Mr. Chairman, is if you look at the leads, if you look at the people on the screen, Mr. Penstone is no longer with the company, Mr. Schneider is no longer with the company, Mr. Rebick is no longer with the company. There are individuals who are in these meetings that are no longer here.

Again, I don't know how and why this material, regardless of its content, is relevant to an application that has been filed where the company is relying on that evidence in this proceeding to justify the relief that's sought.

MR. QUESNELLE: So if -- the clarification you are providing this morning, Mr. Nettleton, is even if it is redacted in red, it may not be relevant?

MR. NETTLETON: Correct.

MR. QUESNELLE: Mr. Rubenstein?

MR. RUBENSTEIN: I understand my friend hasn't agreed that this stuff is relevant. He opposed the production of these in the first place. I think to some degree, at some level, we are past that. I don't agree they are not relevant.

One of the problems that intervenors and, I would submit, the Board always has in proceedings is you don't know the counter-factual scenario. So I think it is relevant if my friend -- I don't know what's behind this, but if a slide says we think we can achieve X amount of savings and ultimately they don't come forward with that or it's in different areas, it is fair for the Board to wonder

what has happened.

I recognize it may not be the exact same people who are up before -- I brought you to the fleet panel because that's the shared services panel that is up later on today. But that they're not the same individuals, I accept that. But that's essentially always the case with utilities; over time, people change and the -- and it's the institution that is, in essence, before the Board.

You know, with respect, all of the important -- as I went through this presentation, essentially I'd submit it's all the important stuff appears to be redacted to make -- to fully understand what was going through the board -- going through this committee and through the company as it was moving from its Good to Great Initiative.

I mean, I don't fully -- if my friend's view is ultimately this is not the most -- it is not the best reflection of what ended up happening or something, that's fine. The Board -- that can go to weight and the Board can determine this was an early draft, things change. Everyone understands that. But I'm not sure why, full stop, it should be redacted.

MR. QUESNELLE: Mr. Nettleton, is there a version that's available to the Panel?

MR. NETTLETON: I'm sure we can -- I don't have it. I'm sure that --

MR. QUESNELLE: It hasn't been filed?

MR. NETTLETON: It has not been filed, no, sir.

DR. ELSAYED: Can you remind me what was the timing of

these presentations, relative to the timing of the presentation to the board?

MR. NETTLETON: Dr. Elsayed, the board presentation -- my understanding is that the board presentation was made in May of 2016. So these presentations -- there was a series of six meetings that took place where there were presentations, and as outlined in the undertaking response, there was a variety of presenters; not every work stream presented at each session. There was differing levels of agenda leads and time for the presenters that came to steering committee.

The first meeting of steering committee was dated February 2016. So it happened there was a period of time between February -- and I don't have all of the dates, but they are on -- they are recorded on the undertaking response with each presentation deck in terms of when the presentation happened.

DR. ELSAYED: So these presentations were made in a period starting February 2016 to some other date?

MR. NETTLETON: Yes.

DR. ELSAYED: And...

MR. NETTLETON: Up until -- between February and May.

DR. ELSAYED: So there was not like -- the argument you were making earlier about the time that elapsed between those presentations and the information in these presentations relative to what has been presented to the board, which you argue is relevant to this application, was not long.

MR. NETTLETON: Sorry, let me be clear. This application was filed in March 2017. So the first presentation happened 13 months before the application was filed. The presentation to the board of directors happened in May 2016, so almost ten months in advance of the filing of this application.

DR. ELSAYED: No, I understand that. But would you consider the presentation to the board in May 2016 and the content of that presentation to be relevant to this application?

MR. NETTLETON: It has not been filed in this proceeding as being something that Hydro One is relying on, because the product of whatever happened in the May 2016 board of directors' meeting then followed subsequent steps that were taken by the company through the customer engagement process, through additional board memos, the consolidated business plans that were filed, and ultimately the presentation of the application that was filed in March 2017.

So again, sir, I think the context here is really important, that what we're dealing with here is a company's ability to work internally through an internal working process, a working committee, a working ability and then a year before -- more than a year before filing an application and having this regulator effectively say it's fair to open the door and have every communication, every document come forward, whether it's a working document or not, that's presented to a committee and be disclosed.

In my respectful submission, there needs to be some guidance and some limitations placed on that type of disclosure. It's not something that the company is relying on. This isn't about, as my friend indicated, you know an institutionalized review of the organization. It is about considering the application that is before this Board and the relief that's sought and having a reasonable basis to test the evidence that the company's relying on.

MR. QUESNELLE: Mr. Nettleton, I think the -- I think we have to take a step back, and think of the evolution of how we arrived at where we are today, just the conversations we had last week.

The original question was: Is there anything akin to the vegetation management report that came out of any one of these streams, these work streams? And I think the response was, well, there may have been a presentation, there may have been a PowerPoint, and the Board ruled that it was interested in that.

Now we have 400 pages of response. That isn't what we had envisioned. That isn't what -- but you described it as we were going along, and it described the work. But the original attempt was to get something that was probably a little more concise, a little more packaged. As it turns out, that isn't the case.

But I think that at this point, to say that this is what the Board should be avoiding and a typical going down to these depths, the response has shown the depths in which these papers go, and there is no recordings of

conversations. I think what the board is looking for is papers, what happened, and would put that to weight and it will do so.

Now, I think the next question is whether or not there is any merit in having this disclosed. You've made your argument on the rationale as to why it shouldn't. And I think the counter-point that Mr. Rubenstein is making is a typical one: Well, how do we know what's there? It has been produced.

And I also take it, just from the few examples that we've seen, is -- and I'm not suggesting you go back to 400 pages and identify this is the nature of this information. I think you've done -- you know, attempted to do that well in the narrative that sets up the response.

But I think that at the very least, we should have a version that this Panel can look at and that's a typical approach that we've taken as a Board, and the Board will take a look at it and rule further.

Mr. Rubenstein, are you satisfied with that at this juncture?

MR. RUBENSTEIN: Sure.

MR. NETTLETON: Mr. Chairman, I do need to comment on one thing, and that is the nature of the original request to see if there was something that was similar to veg management.

I think it's fair to say that the company was very sensitive, very concerned that we would be making judgment calls on things that are obviously not consistent with the

type of presentation that was given to the veg management stream.

As I indicated before, veg management was not one of the work streams.

MR. QUESNELLE: No.

MR. NETTLETON: It was a stand-alone report that was prepared, and we said in our minds, look, we owe it to the Board to be clear and show them the nature of the process that was going on and the level of disclosure that we thought was relevant and consistent, because we did not want to be accused later on of suggesting that we were picking and choosing.

I think that where we have picked and choosed is a reasonable balance by showing you and all parties the nature of the process that was undertaken internally through Hydro One, the context or the type of discussion that you would reasonably expect from the level of disclosure that's been given, and for us then to say, okay, would these reasonably be considered as working papers, as working drafts, as something that's built into the board of director presentation that has been disclosed.

MR. QUESNELLE: Okay.

MR. NETTLETON: So with that, we will get you the --

DR. ELSAYED: Just one quick question. Are the 400 pages all PowerPoint presentations? Forgot about that.

MR. NETTLETON: Yes.

DR. ELSAYED: They're all PowerPoint presentations; okay.

MR. NETTLETON: Over a six -- there were six meetings that took place, and so we felt that it was important to give you all presentations.

MR. QUESNELLE: Thank you, Mr. Nettleton. And the Board does not take it lightly. We appreciate the effort and recognize how much work has gone into this.

MR. RUBENSTEIN: If I could just, if I could make one comment. I am unclear now, is the red material -- as I understood when I first reviewed this that the red material that was redacted was specific to confidential -- things that would normally fall under the Board's confidentiality guidelines, but as I heard Mr. Nettleton's argument, it is more -- it is unclear to me what the difference is between that information and the other stuff that has been produced, because if that falls within its bailiwick of things they don't feel the Board needs to see or parties need to see -- so if it -- my question then through you is: Is the red material more than that category of information?

MR. QUESNELLE: Well, yeah, I've sought the same clarification, Mr. Rubenstein, and the response was, yes, there is a relevance question to the red redaction as well, and I don't know where we go with that. Mr. Nettleton?

MR. NETTLETON: Again, I think that, you know, to place this into context, if someone had a number that presented to steerco that related to a category of distribution expenditure, that at the time in February was a particular number different from the number that's been presented here in this application, then the question is:

What do we do with that? Are we now going to go into an exploratory exercise that says Hydro One is not relying on this information, the way in which it was modified may or may not be explained, because the people -- the resources that were involved in this meeting have not, and do not, are no longer with the company, and quite frankly, I don't know if there is anyone here still with the company that was in attendance at these meetings when there was a discussion that could explain what the difference in the numbers are. So --

MR. QUESNELLE: You will accept, Mr. Nettleton, that that's a rationale that is separate and distinguishable from the rationale of it being financially sensitive, that the descriptor of the material that is redacted in red doesn't go as far as that. It doesn't include that.

MR. NETTLETON: No, no, but it does go, and if I call up the first page again, it's the last paragraph that we -- where we talk about the redactions. And what Mr. Rubenstein did mention was that the redactions do relate to sensitive commercial information related to third-party contract negotiations that have not been publicly disclosed, or staffing matters impacting unionized employees that has not been publicly disclosed and/or that could have an impact on labour negotiations.

MR. QUESNELLE: And what you're adding to that this morning is, or information that may lead to disclosure that wouldn't have any -- wouldn't be warranted because if it's stalemated or --

MR. NETTLETON: I don't know how you for -- example, if a pole replacement metric came in that said, as Mr. -- as my -- as -- if B.C. Hydro's pole replacement cost came into the discussion that said it's $2,000 or $1,500, how does that information become relevant to this --

MR. QUESNELLE: The argument has merit, Mr. Nettleton, I'm just suggesting it's not in the note that Mr. Rubenstein read.

All right. We'll -- well, we'll see what the timing is and what we can do. We'll try to respond to this as soon as we can, but if the Panel could obtain an unredacted version, totally unredacted, and then we'll take a look and go from there.

Okay. Ms. Grice.

**HYDRO ONE NETWORKS INC. - PANEL 5: ASSET MANAGEMENT PLANNING & WORK EXECUTION, RESUMED**

**Darlene Bradley,**

**Bruno Jesus,**

**Lyla Garzouzi,**

**Brad Bowness; Previously Affirmed**

**CROSS-EXAMINATION BY MS. GRICE (CONT'D):**

MS. GRICE: Thank you. Good morning, panel. If we could turn, please, to page 56 of my compendium. So as part of AMPCO's compendium I filed the 2015 asset condition assessment for Thunder Bay Hydro that was undertaken by Kinectrics as part of their 2016 cost-of-service application. And I want to review some of the key findings in the report at a high level with the witnesses.

So in terms of context for this report, Thunder Bay was asked by Kinectrics to perform an asset condition assessment on its key assets to facilitate the development of a distribution system plan, and if you can turn to page 80 --

MR. NETTLETON: Sorry, Ms. Grice, can you just confirm -- I notice in the bottom left-hand coroner there is a reference to confidentiality and proprietary information. Has this been placed on the public record?

MS. GRICE: Yes, it has.

MR. NETTLETON: Okay. Thank you.

MS. GRICE: If we can turn to page 80, please. This is the outcome of the assessment that Kinectrics did for all of the key assets in Thunder Bay's distribution area. They've provided the population of each asset group, the sample size that had data for it, and then they came out with a health index distribution for all of the assets and rated them according to very poor, poor, fair, good, and very good. You see that there?

MS. GARZOUZI: Yes.

MS. GRICE: Okay. Thank you. And then if you turn the page to page 81, just puts the same information in a chart form and shows the distribution of health of those assets, with the red being very poor and the dark green being very good.

And then if we can next turn to page 84, the report -- based on the asset condition assessment that was undertaken, Kinectrics came up with a ten-year flight for

action plan for all of the asset groups that were analyzed in the report as a recommendation to Thunder Bay in terms of quantities of assets to be replaced, recognizing that this proposal was based on condition only.

And then if you can please turn to page 88 of the report. Okay. This is the area that I want to focus on. The other thing that Kinectrics did was they did an assessment of data availability and they did a data gap analysis for each key asset group. And they defined the data availability as relative to what Thunder Bay was currently collecting in terms of data and then the data gap was relative to information that was not being collected.

And they came up with two key recommendations based on this assessment, and the first one was that Thunder Bay should bring its data availability to 100 percent for all of its asset groups and maintain it at this level.

And then in terms of the data gaps they recommended that data that was not being collected be gathered in a prioritized way and that the data gaps would relate to additional sources of data from testing, and they gave a couple of examples of pole strength testing or cable testing.

And you can see those recommendations on page 89 at the bottom, number 7 and 8. And those are the two I just summarized, the first one being bringing the data to 100 percent and the second one being to fill in the data gaps.

So if we can now please turn to page 87. Kinectrics has a finding, and that's in the first paragraph, that

begins after "as such." "Even if an asset group has a high data availability" -- sorry, I'm on the top of page 87, in the first paragraph, third sentence. It begins with "as such."

> "Even if an asset group has a high data availability, this does not mean information for this asset group is complete; i.e., if there are numerous data gaps, the degree of confidence that the health index reflects true condition may still be low."

Would you agree he with that statement?

MR. NETTLETON: Well, Mr. Chairman, I'm objecting to the question. I don't know how this witness or these witnesses would be able to comment on a third-party report prepared for a company that is not related to Hydro One, would be able to comment on the conclusions that that expert has made in this report.

MR. QUESNELLE: Ms. Grice?

MS. GRICE: Well, I'm just putting forward a general proposition.

MR. NETTLETON: But it's not general. It's talking about a specific statistic called DAI that is not something that, I believe, has come on to the record in this proceeding.

Certainly Kinectrics, the author of this report, is not a report that -- or an expert that has testified in this proceeding. I don't know how Hydro One would be able to comment on that.

MR. QUESNELLE: I don't know that this isn't a general observation, Mr. Nettleton. I think that knowing the expertise of the witnesses that -- and there was some discussion of this last week as to how, with a -- I'm thinking back to part of the conversation where there's conditions are not kept on run-to-fail assets because you're not planning on doing anything with it, their determinations are not being made mid-life, those types of conversations.

I think this is in line with that general proposition and I think it's a general comment and an observation. And as for whether or not Hydro One's approach takes this into consideration and if they don't, and it is something that they lack an understanding of what this means, I think that's a fair response as well.

MS. BRADLEY: Not knowing exactly what data is here, if we were doing an assessment like this, we would have meetings to understand exactly the context or the information that Kinectrics was referring to.

But for example, in the last paragraph where it says "underground cables had only age information", I would assume the missing data doesn't help you make a condition-based decision because they only have age data. And they said fewer than half the cable population even had that information.

So with that kind of missing information, yes, I could see that if you had an age-based program, you have half your population for which you are not going to plan work.

So as we talked about earlier, it will result in a smaller program than anticipated. But obviously you are not going to pick those cables up in your program.

I'm not sure if that's exactly what your question was.

MS. GRICE: Thank you. I should have stated that the condition -- that data that they used was test data inspection records, the age of the asset, and the make, model and type.

And I guess if we can go back to page 88 and just look at the table, perhaps wood poles, so this fits with the finding that I just read that they have the data one 100 percent of the poles related to information that they are currently collecting; that's what the data availability is tracking. But the data gap is medium to high, and I referenced the recommendation where they state in it, number 8, that additional sources of data would come from testing, example pole strength testing. So that's the data gap for poles in this example.

So I just wanted to see if you would agree with their statement that if there are numerous data gaps, and you -- even if you have a high data availability, the degree of confidence that the health index reflects true condition may still be low because of that data gap.

MS. BRADLEY: I don't think that you can generalize that statement. With wood poles, if they have a hundred percent of the data of pole test results, but they have -- I'm not sure how they consider it a high percent with a high gap. Say they had a portion of their poles that

aren't in their database at all so they don't have information on that, they are not going to plan to replace them, clearly.

So I think every one of these categories would be very different, depending on the type of information that was being sought and how relevant it is.

MR. NETTLETON: Mr. Chairman, I mean I don't know how to explain the difference between a box on a chart that says all 100 percent average DAI, but how they got to a conclusion in the next column that says data gap of medium to high.

That is, I think, what Ms. Bradley is saying, is that it's not clear.

MR. QUESNELLE: And that provides Hydro One's thinking on how they would approach this.

MS. GRICE: I'll move on. But as part of Navigant's unit cost benchmarking report that was done, Navigant identified a gap with respect to Hydro One's pole testing, correct?

MS. GARZOUZI: Can you please be more specific?

MS. GRICE: Sure. If we could turn to page 102, this is a page out of the Navigant report and at the bottom under section 3.2, "Pole inspection costs and frequency", it says in the third sentence:

> "Hydro One performs visual and light physical inspections on a shorter interval than most other companies (three to six years compared to 10 for the panel) and Hydro One is the only company that

does not use bore, excavation, or ultrasonic methods on a dedicated schedule (seven to 20 years)."

So I take that to mean, in the context of our discussion around Kinectrics, that there is a data gap with respect to testing of poles that was identified by Navigant.

MS. GARZOUZI: I don't think that highlights a data gap. I think what that highlights is a different practice.

MS. GRICE: Okay. And then if we turn to page 101, please. Navigant had a key recommendation regarding pole replacement, which was that Hydro One should consider modifying the pole replacement program to include more complete people inspections: sound, bore, excavation.

Can you confirm, then, that Hydro One is not doing this currently?

MR. NETTLETON: Mr. Chairman, it does go on. In fairness, it says "and a longer approximately 10 year inspection cycle." I think it's only fair to put the whole recommendation to the panel.

MS. GARZOUZI: As noted in the Navigant report, we actually inspect our assets more frequently, so on the six-year cycle for rural and then a three-year cycle for urban, than the peer group in the benchmark. And that is specifically the point regarding the boring on a cycle, or on a time cycle.

So we are considering, or we are looking at more cyclical, intrusive testing or ultrasonic testing and we're

commencing that this year.

Based on our findings, we will adjust the cycle accordingly. It might align with our inspections per the DSC appendix C, or it might be longer or shorter. So we're working through that right now.

MS. GRICE: Can you just confirm that the investment plan that makes up this application, the poles that are proposed for replacement, they do not reflect this more rigorous pole testing; is that correct?

[Witness panel confers]

MS. GARZOUZI: Ms. Grice, can you please repeat the question?

MS. GRICE: I'm sorry, I just -- oh, I was -- I was asking for confirmation that the investment plan, the capital investment plan around pole replacement, the quantities that are in the plan and the spending does not reflect this more rigorous pole testing; is that correct?

MS. GARZOUZI: That's correct. However, the more rigorous testing would find more, so I would look at it not that we failed poles that are not failed. If the hammer is going through the pole at the ground level, it means that there is rot at the ground level. If there is a bore test or there is a lot of woodpecker activity throughout the pole it will jeopardize the structural integrity of the pole. However, additional testing might find something that the current inspector is not finding on the spot. And rot typically exhibits at the ground level and below and at attachments where there is -- premature rot or decay may

occur.

MS. GRICE: Would you agree with me that if you did more rigorous strength testing on your poles you would have noticeably better information to make decisions on which poles to replace?

MS. GARZOUZI: It would depend on the effectiveness of the test. There's many methods out there and they provide different benefits. You might find -- you know, similar to an MRI, you might find, you know, tumours that weren't found before, but you don't know if it's actually jeopardizing the structural integrity of the pole, so it would really depend on the method that you would choose.

MS. GRICE: Okay. Can we turn to page 93, please. And in response to part B you provide the asset analytics algorithms for the assets where you have these. And if we can turn the page to 94, it shows the asset analytics algorithm for wood poles, and it shows the five tests there that you do. A few of them are visual inspections, and then, I believe, there are some light physical inspections as well.

You haven't ranked the weightings of those tests, which is different than what you've done for the other asset groups, and you have a note to explain that. You say:

> "Wood pole supporting factors are considered individually and do not have relative weightings."

But if you were to begin doing a more rigorous

strength testing of poles, would you agree then if you brought that test in that it would have a higher relative weighting than these tests?

MS. GARZOUZI: So I'm not sure I agree with that. So if we look at the elements of that table, a shell thickness of 2.5 inches or less does not meet CSA. Hence that would fail on its own. The hammer test, if the hammer is going through at the ground level and so you are seeing porous wood essentially, that fails the pole. If there is extensive woodpecker damage or extensive damage, you know, visual damage that is -- so visual and woodpecker can be lumped together, because there's something that you are visually inspecting -- that could jeopardize the structural integrity of the pole.

So these elements are bores, if -- so it's not an ants -- so it is not a weighting, and so the more rigorous testing would be another component of this that fits into shell thickness or hammer test.

MS. GRICE: So then would you say it has an equal weighting? Is that what you would give it?

MS. BRADLEY: Can I just add that -- like, those tests you are talking about are going to pick up a condition earlier, but since we go every three to six years, we believe that these tests, which they basically say you have this problem, not you might get it in ten years, so if you were doing other testing it might pick up a condition earlier, but if it's failed one of these tests it already is demonstrating visually the woodpecker damage or the

visual damage assessment, so you would have to act sooner with these tests.

More intrusive tests, the more -- the tests you're talking about are going to allow you to plan for ten years out instead of for six years out. They are just giving you an earlier indicator of poor condition.

MS. GRICE: Okay. Could we turn to page 95, please. This is and undertaking where Hydro One provided the data availability level for certain assets, and it shows that under your station structures and MUS structures you have a 100 percent of the data. For circuit breakers it's 38 percent and then for station transformers, mobile unit substations, and reclosers you've got data less than 100 percent, but in the 80-plus, 80 percent range.

How did you -- what did you base your data availability level on? Is it asset units, or did you bring in an assessment of the information that you're collecting?

MS. GARZOUZI: In this table, what constitutes the percentage are the elements that we would collect as part of our inspections or that we would use to determine the condition or the end of life of the asset.

MS. GRICE: Okay. Thank you. And we've discussed this before, but you've indicated for all of your line assets the condition is recorded on an exception basis, and therefore condition data availability is less than 100 percent.

Do you have a data availability level for poles? Do you have a percentage for that?

MS. GARZOUZI: We have 100 percent for poles.

MS. GRICE: Okay, thank you.

And if we could turn to page 54, please. This is a memo that went to your board of directors, and if you turn the page to page 55, under part C, "Investment plan process", it says:

> "Hydro One's investment plan and process is based on ISO 55000 principles, which are best practices for holistic asset management."

I'm not familiar with ISO 55000, but as a follow-up I wanted to ask: Does that standard recommend that assets be collected -- that asset condition be recorded on an exception basis? Is that something that comes out of that standard?

MR. JESUS: So the ISO 55000, it was -- is a -- came afterwards, past 55, which is the publicly available specification for asset management. They've actually subsequently turned it into an ISO governance model.

I'm not sure whether or not the ISO 55000 talks about collecting of condition information. It's more process-oriented, which indicates that you have to have some process that determines what the condition of the assets are and make the right decision.

But specifically, I can't talk to it. I'm not up-to-speed on what it says regarding condition.

MR. BOWNESS: I think one piece for context that's important is when we are capturing defects on an exception basis we by default are also capturing information of -- on

a positive basis, and we're just not writing it down in the system. We're not saying that the pole is fine, the cross arm is fine, the guy wire is fine. It doesn't -- we don't do anything with that. We capture the defect associated with each one of those attributes, so we don't see that there is any need to capture the positive record of okay; we capture the defect. And therefore, based on having the defects, we can do percentages. We can say this many poles have failed the condition test out of the 1.6 million, as an example.

MS. GRICE: I'm going to move on to a new area. Page 1, please. At the very bottom there, this is a page out of your 2016 annual report and the paragraph title is "Risks relating to asset condition and capital projects."

And I note that this same passage appears in your 2015 annual report, so it's a, I guess, a condition that has existed for a while. I'll just read it:

> "The company continually incurs sustainment and development capital expenditures and monitors the condition of its transmission assets to manage the risk of equipment failures and to determine the need for and timing of major refurbishments and replacements of its transmission and distribution structure. However, the lack of real-time monitoring of distribution assets increases the risk of distribution equipment failure."

Can you just explain further what that risk is?

MS. GARZOUZI: This speaks to the way we operate the distribution system. We talked about the distribution system is largely not monitored and not automated, and so we don't have real-time monitoring. For example, if the transformer is approaching or exceeding its loading limits, we're not seeing that in real-time or near real-time, whereas on the transmission system, we do have all that information to the second, to the minute.

And so this is really less about a condition and more about operations, utilization of the system, loading of the system.

MS. GRICE: Is there a long-term plan to address this risk, or is that just the nature of the distribution system?

MS. GARZOUZI: So over time, it would be -- as we monitor and control and automate the distribution system, we would be addressing that risk. And so the transmission grid starts resembling more of a transmission grid, but again, it has to be cost-effective in order to do so.

So not all circuits -- some circuits it may not be cost-effective to have automated switches on them or automated monitoring. And for many it will be, and we'll get there over time. But it's a journey; it will take some time.

MS. GRICE: Thank you. My next area -- I apologize, I don't have the page in my compendium, but I did give a reference to Hydro One on Friday and it may have been miss -- moved along, but I'll give the reference. It is Exhibit

B1, tab 1, schedule 1, section 1.3, page 17.

And I asked this question at the customer panel and I was asked to bring it forward to panel 5. So it is just relating to the first bullet:

> "For large customers, power quality events and unplanned momentary power interruptions of less than one minute, rather than sustained interruptions of one minute or more, are the primary concern. Some customers have capacity challenges and want more access to power in order to grow their enterprises."

My understanding is there are components in the investment plan that address power quality, but I just wanted to further understand, from a systematic perspective, what the limitations are around tracking momentary power outages.

And I should -- sorry, we did ask an interrogatory to ask if you were tracking MAIFI and MAIDI and the response was that you are not, and I'm just wondered what the limitations are to do that.

MS. GARZOUZI: Ms. Grice, it's along the similar lines that we just discussed. So it's that the distribution system is not monitored, with the exception for the Owen Sound area, which is a Smart Grid area where we had a pilot and we automated a lot of the system there.

So for the rest of the province, we don't have that level of monitoring, which means we don't have visibility for momentary interruptions which is different from the

transmission system, which we would have that level of visibility.

MS. GRICE: Okay. And long term, is that something that, as you change your system, that might be able to be captured?

MR. JESUS: Yes. Going forward, we're looking at leveraging the smart meter network to be able to start reporting on momentary interruptions. So the actual smart meters that we have in people's homes, we would bring back that information and start reporting on the momentaries.

MS. GRICE: Okay, thank you. If we could please turn to page 110, this is the distribution scorecard, and under pole replacement, you've got gross cost per unit. And when -- if will you take it, subject to check, that when you add up 12, 13 and 14 and arrive at an average, it is $8,398 per pole. Will you accept that, subject to check?

MR. BOWNESS: Subject to check.

MS. GRICE: Thank you. And if you could please turn to page 104, this is a page from the Navigant study and under "Pole replacement costs", the last sentence says:

> "Across the comparison group, the average cost to replace a pole is $7,105. For Hydro One, that cost is $8,266."

So that's a different number than the one I just read to you that came out of the scorecard of $8,398.

Are you able to account for the difference between those two average costs for the same time period?

MR. BOWNESS: Yes, we are. The Navigant benchmarking

approach asked for specific breakdowns of specific types of costs, labour, material, fleet equipment. We made sure that we were specifically answering to those buckets that Navigant asked for, so that we could benchmark across the other utility sets.

And we do know what the deltas are between the small amount of dollars which is -- sorry, could you just repeat the average that you had?

MS. GRICE: Sure. 8,398.

MR. BOWNESS: So it's about a 130-dollar difference, and the differences in that are some of our miscellaneous charges and some of our procurement card charges that are within our broader corporate common groups that get allocated across.

So really the Navigant benchmark was really the bottom-up, apples-to-apples comparison of direct costs on pole replacement, and then we did have a small percentage of dollars that were an allocation from the rest of the business. But Navigant did not ask us to provide that information.

MS. GRICE: Okay. Are you able to provide the pole unit costs for the years 2015 to 2022, using the same methodology as the Navigant report, so that we can do an apples-to-apples comparison with this report?

MR. BOWNESS: So the data that we've provided in SEC 29 is the forward-looking view of our unit cost projections following our fully grossed-up costs.

If we were to look at our average delta in the

Navigant study of about $130, you would effectively subtract $130 from those projections in SEC 29, and that would be in line with what would be in the Navigant information.

MS. GRICE: Is it possible to get the specific calculations for those years?

MR. QUESNELLE: Ms. Grice, I think it's been demonstrated, looking back anyway, and the evidence just given is that it would be the same going forward. It is 138 delta per pole.

I'm just -- I'm looking for a -- I recognize that there is a difference, but I think it's been explained that that is the difference. I think precision on that, unless I'm missing something...

MS. GRICE: No, that's fine, that's fine. Thank you.

And then we just had one -- another area where the historical cost for poles appear to be different than what's in the application. Can you please turn to page 108 and 109. And I'm looking at the historical cost for 2012 and 2013. And then the number of poles replaced. So the 55.5 and the 73.9, and then the number of poles replaced on the next table, 7,452 and 10,720. That's from the last application. I'm sorry, I didn't specify that.

And then if we go to the DSP, B1-1, section 1.6, attachment 1, page 14, it's showing different numbers, and I guess I'm just looking for clarification on the numbers that are in the last application compared to what's in this application in terms of pole cost and number of poles

replaced. And maybe the easiest way to do this would be by undertaking just to account for the difference.

MR. BOWNESS: So could you just explain one example, and then I think I'll be able to respond. So maybe we could take one of the years that you're suggesting there's a difference. Could you pick one that you're seeing a difference?

MS. GRICE: It is 2012 and 2013.

MR. BOWNESS: Okay. So in 2013, if we can scroll up, you're seeing the cost for pole replacements at 73.9 million?

MS. GRICE: Right.

MR. BOWNESS: To replace -- if we could scroll down to 2013's number of poles, would be 10,720. So based on my math, subject to check, that would be $6,893 and that is a delta to what would be in the OEB scorecard table, which would show that the average pole replacement cost would be 7,824; correct? That's the example delta that you are looking to have explained?

MS. GRICE: Yes.

MR. BOWNESS: Okay. So the difference between these two numbers is the difference between gross and net costs, so the difference that we have on a replacement is a replacement includes removing the old pole, and it is approximately 10 percent of the cost, so if you look at the delta that's in this table, this is -- the evidence in your compendium is net cost. The number that's within our scorecard is gross cost.

MS. GRICE: Okay, okay. Thank you.

And I just have two quick questions. One is a follow-up. You've said in questions regarding your capital plan that high-risk means you replace the asset within five years.

Do you actually do that? Is that something that you track and execute in that way?

MR. BOWNESS: So if you look at the way we plan the asset, the failed condition high-risk is an asset that has a high probability of failure in the next five years, and that's what's formed the basis of the number of poles that we have in a high-risk or a poor asset condition.

We then go through an exercise to prioritize work from an execution perspective, to deliver that work as efficiently and effectively as possible, so we would bundle work together, we would look at geographic distribution, we would make sure that we have the crews and the resources, the fleet, equipment, in order to replace the poles, and we would balance that execution between items that are in that portfolio of 72,000 poles that we would replace over the five-year period, and look to deliver it on the most cost-efficient manner.

MS. GRICE: Okay, thank you.

And my last question: Just in terms of the interplay between the distribution capital budget and the transmission capital budget, if you have a priority in the distribution business or the transmission business, does money flow between the two capital programs?

[Witness panel confers]

MS. GARZOUZI: So when we prioritize investments there is no trade-off between the transmission dollars and the distribution dollars. The flowing between T and D would be for things like, there are instances where distribution is a tenant on a transmission corridor, and so there is a rental fee that is charged, or there are instances where distribution is paying transmission for a capital contribution project, but there isn't a trade-off amongst capital between those two businesses; they are separate and distinct.

MS. GRICE: Okay. Thank you, those are my questions.

MR. QUESNELLE: Thank you, Ms. Grice.

Mr. Sidlofsky? Can we target about 10:40, if there's a natural spot in your cross around 10:40, Mr. Sidlofsky? We'll start the break then.

MR. SIDLOFSKY: I'll keep that in mind, sir. Thank you.

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

MR. SIDLOFSKY: Good morning, panel. My name is James Sidlofsky. I am counsel for Board Staff. And I have a number of areas to take you through, but I'll start with your proposed level of spending and associated reliability impacts.

According to Hydro One, the plan detailed in your distribution system plan which corresponds to Plan B modified sets out the minimum possible rate increases or the minimum investment level required to sustain constant

reliability performance over the planning period.

Is that an accurate characterization?

MS. BRADLEY: The desired outcomes is to get the right balance between customer needs, between sustainability of our assets and the needs of the assets in the system, and to maintain reliability. It's the combination of the three.

MR. SIDLOFSKY: Okay, and would it be fair to say that you've rigorously and accurately validated that your reliability performance can't be held constant unless you make the expenditures that you've proposed under Plan B modified?

MS. BRADLEY: We have the tools at our disposal to rigorously and accurately predict the impact of the spend on assets condition and our ability to sustain the fleet of assets.

I know in the areas where we've got the table that walks through scenario A, B, and C and the impact that those scenarios have on reliability, we do state that those are high-level assumptions that are put into coming up with that reliability assessment.

There are many factors that contribute to the reliability outcome.

MR. SIDLOFSKY: Okay. Maybe just for reference I can take you to page 2 of the Staff compendium.

MR. QUESNELLE: Do we have a Staff compendium, Mr. Sidlofsky?

MR. SIDLOFSKY: Sorry, sir, Mr. Davies has copies for

the Panel.

MR. QUESNELLE: You certainly do have a Staff compendium.

MR. SIDLOFSKY: And that would be Exhibit K9.1.

**EXHIBIT NO. K9.1: BOARD STAFF CROSS-EXAMINATION COMPENDIUM FOR HONI PANEL 5**

MR. SIDLOFSKY: So perhaps, Ms. Bradley, I can ask that question a different way: Do you need to do all of the expenditures you are proposing under Plan B modified to maintain reliability at its current level?

MS. BRADLEY: We do know with the vegetation management program that we are introducing we expect a reliability improvement. And we've had a lot of discussion over that over the last few days. We do need that level of spend to be able to maintain the current condition of assets.

But as we've discussed a number of times, the vegetation management program will introduce an improvement to reliability.

MR. SIDLOFSKY: Okay. At page 3 of the compendium, we've reproduced Exhibit B1.1, which is distribution plan section 2.4, page 2 of 8.

And in that extract, Hydro One explains that the level of capital spending in each scenario is related to reliability performance and that reliability impacts for the proposed scenarios were modeled using the effective relative investment impacts for vegetation management, pole replacement, and distribution stations and other line

components. The first three that I mentioned are the contributors to the majority of reliability impacts.

And you've summarized the impact on SAIDI and SAIFI for each scenario in tables 52 and 53 of section 2.4 of the DSP, and those are on pages 4 and 5 of the Staff compendium.

Perhaps I could turn you to table 52 first, the SAIDI projections. Under the contribution to SAIDI column, is it fair to say that the overall impact on reliability is more highly weighted on vegetation management with a 27 percent contribution to SAIDI relative to other line components, poles and stations?

[Witness panel confers]

MR. JESUS: Again, I'm -- yes, vegetation is a big contributor to SAIDI. I think the updated numbers again are in the Energy Probe 17 exhibit and we subsequently provided the numbers under an undertaking.

But yes, vegetation is definitely a big contributor towards SAIDI.

MR. SIDLOFSKY: And would similar thinking apply to table 53 on the next page of the compendium?

MR. JESUS: That's correct.

MR. SIDLOFSKY: So contributions of other line components at 18 percent and vegetation management at 16 percent are also more highly weighted than poles and stations?

MR. JESUS: So could we turn to I18, Energy Probe 17 for the latest and greatest calculations?

MR. SIDLOFSKY: Absolutely.

MR. JESUS: Perfect. So in this interrogatory, vegetation is contributing 31 percent and defective equipment is 30 percent, in total.

MR. SIDLOFSKY: Sorry, I'm seeing vegetation 31 percent. Where is the 30?

MR. JESUS: I saw poles station and other line components to categorize it as defective equipment, which adds up to 30 percent.

MR. SIDLOFSKY: Okay. Now, if I could take you back to page 6 of the Staff compendium, OEB Staff Interrogatory number 164. That was Exhibit I, tab 29, schedule Staff 164, asked that -- asked Hydro One to calculate the different SAIDI and SAIFI impacts that would result from implementing each of the plans.

And Hydro One provided a sample calculation for poles, and that's shown on page 8 of the Staff compendium. We've given you the full response, but I'd like to take you to the last page of that interrogatory response.

The reliability calculations shown in that table suggest that under Plan B modified, if you replaced 7 percent of your poles, your reliability impact is also 7 percent. So -- in the table, to be fair, it's 6.6 percent change in fleet condition for poles, and a 7 percent positive reliability impact.

You'd agree that's essentially a one-to-one ratio? If you change out 1 percent of your poles, you've got a 1 percent impact on reliability?

MR. JESUS: Yes, that's correct.

MR. SIDLOFSKY: And just to make sure I understand it, that's a 7 percent impact on the 3 percent reliability impact attributable to poles in table 52?

MR. JESUS: That's correct, and the tables, the way they're done, all the contributions would then be multiplied by that performance improvement. So you'd actually end up with the contributions multiplied by the percentage improvements, right?

So if we go back to your table 52, you can see that for poles, there, it's shown as .2 contribution. The .2 would then be multiplied for each one of the performance improvements associated with plan A, B, C and B modified to arrive at the overall contribution for poles.

MR. SIDLOFSKY: Okay. I guess my question that comes out of that, though, is that's only roughly a .21 percent impact on SAIDI; is that right?

MR. JESUS: For which plan?

MR. SIDLOFSKY: Under Plan B modified.

MR. JESUS: It would be 7 percent times .2 would be the contribution for Plan B modified for its poles. Yes, that's correct.

MR. SIDLOFSKY: My question then is whether you consider it prudent to make such a large investment, because poles represents such a significant capital investment, to obtain what seems to be a very small performance improvement.

MR. JESUS: So from a --

[Witness panel confers]

MS. BRADLEY: The numbers that we see reflected in this chart represent actuals, historically, and we've had a proactive program to manage our end-of-life pole population which has helped to keep this number in check.

So our pole replacement program is based on not letting that fleet deteriorate beyond what it is today to enable these kinds of outcomes. So I would expect a more significant derivation from what we have today if all of a sudden we said let's just let them all go. And it would take a long time to catch up and recover from that.

MR. BOWNESS: Another reason why we think it is very prudent in the interrogatory that we submitted the other day is that from a public safety, reliability, and a cost perspective, it's a more -- it's a better approach to make sure we don't have poles falling down which lead to long outages to restore poles on a reactive basis. It also leads to higher cost to replace a pole on a reactive basis.

So yes, we do believe it's prudent to move forward with the number of poles that we've recommended to be replaced in this plan.

MR. SIDLOFSKY: Does the impact on SAIDI, the calculation of the impact on SAIDI account for any weather variability?

MR. JESUS: So that calculation, again, the contribution from poles in the updated table is roughly 0.5. But the loss of supply and the force majeure events have been excluded from that calculation, if that's what

you're asking.

So it's basically the contribution strictly from a normal or storm day, without the storm day being force majeure days, if that helps.

MR. SIDLOFSKY: Okay, and is there any -- that does help. Thank you. Is there any confidence interval or expected range of variability around those numbers as a percentage of overall reliability impact?

MR. JESUS: Sorry, just confidence around which number?

MR. SIDLOFSKY: Around the 7 percent.

MS. BRADLEY: When we presented these numbers to our board, and this is in our board memo that's filed in SEC.4, we do have a note that said SAIDI and SAIFI impacts are calculated on high-level estimate basis using simplified assumptions and are approximate.

It wasn't -- this was to give a feel for directionally where would reliability go with different scenarios around maintaining our asset fleet.

MR. SIDLOFSKY: So you have no sense of 7 percent give or take a certain percentage or anything like that?

MR. JESUS: I would suggest to you that the 7 percent is calculated, as we've shown in Staff interrogatory -- Staff 100, as well as the subsequent interrogatories that we filed for all the calculations in the latest spreadsheet that was submitted as the update to Energy Probe 17. And it really is a simplistic calculation, basing the relationship based on the level investment for each one of

those categories.

MR. SIDLOFSKY: So because it's that high level an approach, Hydro One -- sorry, is Hydro One able to confirm that there is this linear relationship between the individual replacements and expected reliability?

[Witness panel confers]

MR. SIDLOFSKY: So put another way, if you move to more or less than 6.6 percent, are you anticipating that it -- that the reliability increase is going to correspond to that new change?

[Witness panel confers]

MR. JESUS: I would suggest to you that the -- we've used the best information that we have available based on historicals and the contributions to SAIFI and SAIDI, and that's how we've arrived at those calculations.

MR. SIDLOFSKY: So you don't know whether changing 5 percent of your poles out will lead to a 5 percent reliability increase?

MS. BRADLEY: We've used our historic actuals. Year to year there are so many factors beyond asset condition that impact reliability. There are storms, there's motor-vehicle accidents, there's a number of events that take place and influence. We've used the best information that we have available, and I can't guarantee it's going to be exactly like that next year. There's external factors that have an impact.

MR. SIDLOFSKY: Okay, could we go to page 10 of the compendium, please. And at lines 17 and 18 of that extract

from the transcript from the March 5th session of the technical conference, that's at page 40 of the transcript, and at lines 17 and 18 Hydro One confirms that the same logic that you followed for poles would be applied to other components.

And in Undertaking JT3.10 from that technical conference -- and that is at pages 11 to 13 of the compendium -- you've provided some similar tables and calculations related to changes in fleet conditions and reliability impacts, so on page 11 of the compendium you have a similar table for stations, and with respect to that table you explained that the original calculation shown in tables 52 and 53 assumed that eliminating all stations in poor condition -- that's Plan A -- would lead to a 14 percent improvement in station reliability.

Now, the updated calculation provided in Undertaking JT3.10 assumes that eliminating all stations in poor condition is expected to only lead to a 9 percent improvement in reliability. And corresponding reliability impacts for the other plans are then calculated relative to that assumption.

Can you tell me how the 14 and 9 percent were calculated and why the assumption changed between your original filing and the undertaking response?

MR. JESUS: So the 9 percent, what we did when we calculated this updated table was we looked at the stations that were in poor condition and their contribution to the overall SAIDI and SAIFI impact. And what we found was that

the stations that are in poor condition and the ones that have failed only contributed 9 percent towards the unreliability. Ergo, that's why we changed the number from 14 to 9 percent.

MR. SIDLOFSKY: And do the calculations assume that every station presently assessed as being in poor condition will fail over the forecast period unless it's refurbished?

MR. JESUS: Yes, that's correct.

MR. SIDLOFSKY: And what's the basis for that assumption?

MR. JESUS: The basis is that the transformers and the stations have a high probability of failure. They have been assessed. The transformers are in poor condition, and the expectation is that they would be -- that they would have a high probability of failure within the next five years. And so the assumption was that they would fail.

MR. SIDLOFSKY: But as part of Plan B modified you are proposing to maintain a total of 70 stations in poor condition to -- in order to maintain constant reliability?

MR. JESUS: That's correct.

MR. SIDLOFSKY: So are you anticipating that those 70 stations will fail?

MR. JESUS: I guess I can't speak to exactly when they're going to fail. No one knows exactly when they're going to fail. No one in the industry knows when a station or a transformer is going to fail. From a probabilistic point of view, the answer is, yes, we expect that those stations would fail, but with Plan B modified we're

maintaining the level of condition that we currently have, so right now we have 70 stations in poor condition. The plan that's before this Board would maintain that level at 70 stations.

MR. SIDLOFSKY: Moving to the next page, page 12 of the compendium, there's a similar table for other line components, and further line components, you say on page 2 of the undertaking that the calculations are relative to Plan B, but the relationship between the reliability impacts of Plan B and the reliability impacts of other plans isn't entirely clear.

Could you take me through your calculation for this category and explain how the reliability impacts are calculated for each of the plans? So for example, how's the initial negative 5 percent reliability impact from Plan B modified calculated?

MR. JESUS: Okay, so with plan -- let's just start off at Plan -- let's start off with Plan A. So Plan A, the funding available to address line components in the plan was $50 million. And $50 million, assuming that we would address defects in the system and that addressing those defects would mitigate or improve reliability by addressing those defects, at $2,000 a defect we end up with 25,000 defect corrections over the plan period, so with 25,000 defects corrected, we took -- and there's 300,000 defects currently on the system -- we subtracted the 25,000 from the 300,000, which is the basis of that calculation, or an 8.3 percent improvement.

For Plan B modified, the plan before this Board, only $9 million in funding is available to deal with line components. And when you follow the same logic, 9,000 components -- actually, below 9,000 -- sorry, we have $9 million less in Plan B modified, $9 million less, at $2,000 a defect, gives us 4,500 defects or 5,000 defects, which is a reduction of 1.7 percent. That was the logic that we applied.

MR. SIDLOFSKY: Okay, thank you.

Could I take you to page 13 and the discussion about vegetation management. At page 3 of that undertaking response Hydro One says that there is a 9 percent improvement expected to offset the increase in the vegetation backlog, and in the spreadsheet provided in your response to Undertaking 6.10 -- and I apologize, that's not in the compendium -- there's a note under Table 10 that says:

> "The 9 percent impact to reliability is based on vegetation management feeder model impact on reliability."

Could you explain what the vegetation management feeder model is and how the 9 percent was calculated?

MR. JESUS: Sure, so the feeder model, basically, all the feeders are on a right-of-way vegetation management cycle. And so Plan B modified -- plan A, B and B modified would have moved a thousand kilometres from the high priority rights of way -- sorry, would have moved it from the low priority rights of way to the high priority rights

of way, and the incremental -- so the model that we have shows all the feeders and all the cycles, and the current cycle that they're on, and what we did was we looked at the impact to SAIFI and SAIDI based on moving that 1,000 kilometres from low priority to high priority.

So on the low priority rights of way, we would have a 1 per cent reduction in SAIDI. And by moving the thousand kilometres to the high priority, they actually looked at it and which rights of way would be cleared and the impact associated with each feeder, and we determined that there would be a 9 per cent improvement associated with it.

Ergo, the 9 per cent improvement in moving the thousand kilometres to high priority, less the 1 per cent degradation, gave us 8 per cent for Plan A, B and B modified.

We then followed the same process for Plan C, except in Plan C, we removed a thousand kilometres and again, we looked at the model and what would mean from removing 1,000 kilometres from the plan and what the impact would be, and it would be 9 per cent less the 4 per cent for an -- sorry, less 5 per cent for an improvement overall of 4 per cent.

So it is a model that's being run in the background to arrive at those calculations. However, from an OCP point of view, from an optical cycle protocol, these numbers are totally irrelevant because the benefits that we've stated, we will achieve a 20 to 40 per cent improvement over the five-year period.

MR. SIDLOFSKY: I'm sorry, you are suggesting that the

discussion about the 9 per cent is really superseded by your updated vegetation management plan? Is that correct?

MR. JESUS: That's correct.

MR. SIDLOFSKY: Mr. Quesnelle, it's 10:40 right now. I've got a couple of more questions in this area. I think I could be finished in about five minutes.

MR. QUESNELLE: Certainly. Carry on.

MR. SIDLOFSKY: Taking you back to page 12 of the compendium, you also confirmed that other line components is funded under project SR-10, distribution lines planned component replacement, correct?

MR. JESUS: That's correct.

MR. SIDLOFSKY: If we could go to the table starting on page 16 of the compendium, that's an extract from Exhibit B1.1, section 3.7 of the DSP. The total spend for ISD SR-10, and that's actually shown on page 17 of the compendium, is approximately $35 million over the planning period. That compares to SR-06, which is station refurbishment of $148 million, and pole replacement, SR-09, at 579 million.

And I think you could confirm that tables 52 and 53 that we saw earlier show that other line components have a significantly higher reliability impact than both station refurbishments and pole replacements combined; would that be accurate?

MR. JESUS: Yes, that's accurate.

MR. SIDLOFSKY: So is it reasonable to suggest that a dollar spent on SR-10 would provide higher reliability

improvement impacts than a dollar spent in either SR-06 or SR-09?

MS. BRADLEY: No, that's not fair to say. There aren't early indicators of condition for line components, so while we can rely on oil samples for power transformers and stations in a test on a pole to know to replace it before it fails, we don't have that same level of information on the other line components. So we could spend it and we wouldn't know what condition it's in.

MR. SIDLOFSKY: So did you consider at all reducing spending in station refurbishments or pole replacements, and increasing spending in line components, SR-10?

MS. BRADLEY: It's similar. Given the nature of those other line components and the inability to do -- or the fact that we don't have a proactive test to identify an impending failure, there wouldn't be a value in doing that.

So we've planned to maintain the condition of the assets for which we can man monitor condition, and replace assets in a planned manner.

MR. SIDLOFSKY: Sorry, if you could just bear with me for a moment.

Now, on Thursday last week, Mr. Rubenstein had a similar discussion with the panel. The discussion took place in volume 7 of the transcript at pages 138 to 140, and unfortunately I don't have that in the compendium. But Mr. Rubenstein suggested to you that since Plan B modified was approved under the premise that the capital envelope would maintain overall system reliability at current

levels, there should be room to adjust the capital program as a result of the significant improvement in reliability resulting from the revised vegetation management plan, and you disagreed with that at the time.

Now, we've just gone through four sets of calculations that Hydro One used to derive the expected system reliability based on impacts of the four key drivers of poles, stations, other line components, and vegetation.

So is it not plausible that you could use the same simplified linear calculations that you used to adjust spending in those four areas already in order to maintain status quo reliability?

MS. BRADLEY: The plan that we have is based on achieving a balanced set of outcomes. So we've used the OEB's Renewed Regulatory Framework that focuses on customers, operational effectiveness, public policy responsiveness, and financial performance. It isn't only reliability that drives our investments; it is sustaining our fleet of assets.

So we didn't do a lot of investigation of scenarios that would focus on only one factor; we focused on the balance of factors for long-term sustainability.

MR. SIDLOFSKY: But do we agree that status quo reliability is the basis of the Plan B modified proposal?

MS. BRADLEY: I view the primary driver of the Plan B modified as being to sustain the fleet of assets and not to enable them to deteriorate. We can walk through some of the board materials that we presented when we were going

through plan A, B, C and B modified, and in that material, I can walk you through where we demonstrated to our board of directors the impact on our fleet and the condition of our fleet as a primary factor in the discussion with our board, and then we came back with Plan B modified to enable that sustained plan.

MR. SIDLOFSKY: The discussion about the RRFE and improving reliability really only seems to have come up during the hearing, though. My understanding of Plan B modified was that you were maintaining reliability.

MR. BOWNESS: Sorry, I think something that's important here is between the time of submitting the evidence, which was based on a Board approval around maintaining reliability, we came up with a very innovative approach of implementing our new vegetation management strategy.

We looked at the cost envelope that was submitted to the Board and we challenged ourselves to do better, and we've committed to doing better.

If what you're suggesting is that based on being able to achieve a better outcome in a certain area for lower cost would allow us to then degrade the assets from another dimension and do fewer pole replacements of poles that have a high likelihood of failure, I think that that stretch -- what I struggle with is that if we don't replace those poles on a planned basis, they are going to fail -- have a high probability of failure on a reactive basis within the next five years. So the cost of trouble and storm and such

will go up.

So I'm really not seeing the correlation to making a better strategic decision on vegetation management should result in us degrading our asset base, to negatively impact reliability and cost for our ratepayer.

I think macro-ly there has been some discussion here around Hydro One's reliability performance and comparing to other utilities, and if we could just, you know, for reference pull up the chart within Exhibit A, tab 5, schedule 1, page 35 of 52, this is the summary level SAIDI impact of ourselves as compared to other Ontario LDCs, so if we could just pull that up for a second, page 35 of 52.

So if you look at this, with the exception of the 2013 year, which was -- that was the -- which was a direct impact of most utilities with the ice storm, I think it's fair to say that Hydro One's performance is far poorer for Ontario ratepayers as compared to the other major LDCs. That's the nature of the size of the stack bars. And we are really challenging ourselves to improve our reliability. We want to achieve a better outcome. We believe that for the costs that our ratepayers in Ontario pay, they deserve better reliability, and that is why the basis -- that's one of the basises (sic) for our vegetation management strategy is to get this in check. We don't believe that we should be harvesting that savings and degrading the assets and passing on costs to future periods and future generations.

MS. BRADLEY: But I'd also like to add that I strongly

disagree with your strong characterization that reliability was the only thing that was mentioned and that the fleet of assets and condition is only now coming up. In every piece of documentation we have in our business plan, our summary on the top of the second page talks about the need of the plan to appropriately align the needs and preferences of customers, customer rates, and effective stewardship of the distribution system by Hydro One.

In every board meeting we talk about reliability, we talk about condition of our assets, we talk about being sensitive to our customers and rates. I don't know that I can find any spots in our documentation, whether it to be to the board or to our board of directors, where the fleet of assets and the condition of our system aren't forefront in any discussion that's taking place.

MR. SIDLOFSKY: Sorry, Ms. Bailey (sic), maybe I wasn't clear. I wasn't suggesting that the condition of your assets has only come up recently. What I'm suggesting is that you came to the Board with a plan that maintained the reliability of your system and balanced that against prices for customers. That was Plan B modified, correct?

MS. BRADLEY: It maintained the condition of our assets, the reliability of the system. It considered shifts in our capital plan to mitigate the risk of first-year rate impacts.

I don't recall anywhere seeing that it was only about maintaining reliability and those other factors weren't involved. It's a balance. It's a balance between all of

them.

MR. SIDLOFSKY: And again, I'm not suggesting that maintenance of your assets wasn't a consideration in developing Plan B modified, what I'm referring to is your discussion with Mr. Rubenstein where you began to talk about the RRFE in the context of improving -- improving your vegetation management practices and improving reliability where Plan B modified involved the maintenance of the reliability of your system at the status quo. That's what I'm referring to.

So again, if status quo is the basis of your Plan B modified proposed -- excuse me, status quo reliability is the basis of your Plan B modified proposal and the premise for the applications that Hydro One listens to its customers and since cost was a primary concern you chose Plan B modified because it provided the lowest rates while holding reliability constant; is that correct?

[Witness panel confers]

MR. BOWNESS: Yes, and subsequent to that we determined a way to achieve a better outcome, improved reliability, for the same cost as was submitted in the plan. So I -- our ongoing approach with vegetation management of maintaining the cost of approximately $150 million a year and achieving a 20 to 40 percent improvement in reliability I believe is absolutely in line with our ratepayers' expectation of keeping costs in check and delivering the best possible outcome.

MR. SIDLOFSKY: Okay, thank you, Mr. Bowness.

Those are my questions in this area, sir. I'm moving to another area, so this would probably be a good time for the break.

MR. QUESNELLE: Okay. Let's do that. We'll return at 11:10.

--- Recess taken at 10:55 a.m.

--- Upon resuming at 11:15 a.m.

MR. QUESNELLE: Okay, Mr. Sidlofsky, whenever you're ready.

MR. SIDLOFSKY: Thank you. Panel, I'd like to ask some questions about your bottom-up budgeting approach.

If I could take you to pages 27 and 28 of the compendium, those are extracts from the March 5th session of the technical conference and specifically pages 120 and 121 of that transcript.

On lines 21 and 22 of page 120 of the technical conference excerpt, Hydro One states that:

> "There is no capital spending target set from an investment planning point of view."

And on lines 7 to 9 of the following page, you go on to state that planners are focused strictly on a bottom-up approach to identify the needs of the system. Is that still an accurate statement?

MR. JESUS: Yes, it is.

MR. SIDLOFSKY: Okay. Page 30 of the compendium is an extract from Exhibit I, tab 24, SEC 40, attachment 11, and specifically that's page 2 of attachment 11 of Hydro One's response to SEC Interrogatory No. 40.

Under the AIP term "Optimizer", it is stated that the asset investment planning optimizer tool determines the best selection and timing of investment alternatives, maximizing risk and satisfying the financial constraints and dependencies."

I'm reading that accurately, right?

MR. JESUS: Yes, that's correct.

MR. SIDLOFSKY: At page 32 of the compendium, in your response to Staff interrogatory 89, A1, and that's Exhibit I, tab 24, Staff 89, page 2 of 6, you provided a table of financial parameters used in the initial AIP optimization.

Is it fair to say that the optimizer starts with user defined financial constraints that you've shown in table 1?

MR. JESUS: I'm sorry, can you repeat that question?

MR. SIDLOFSKY: Sure, is it fair to say that the optimizer starts with user-defined financial constraints as you've shown them in table 1?

Maybe I'll go on so I can get one -- a single answer to a couple of points from you. And then is it also accurate to say that it takes into consideration all the investments available to the tool -- to the system, and optimizes it by find the maximum amount of risk mitigated while adhering to the defined financial constraints?

MR. JESUS: The planners don't actually see what that final number is. They're focused in on developing the candidate plans to mitigate the risk that they have on the system.

So we're developing plans to mitigate asset risk,

system risks, as well as address customer needs and preferences. They have no line of sight, I'll suggest to you, to the over-arching envelopes that are shown there in your Staff 89. That envelope is informed might previous business plan, as well as direction provided by the Ontario Energy Board.

I've also indicated in this -- I've also indicated that it is an iterative process whereby we look at the starting business plan. We look at the customer needs and preferences. We look at the various risks that is we have on the system, which is exemplified by the A, B, C and B modified that went to our board of directors where, bottom line, they said this was not satisfactory, that we had to come back with a B modified that minimized rate impacts in 2018, and reduced actually the envelopes from there.

MR. SIDLOFSKY: So are you saying that the financial parameters that you've shown in table 1 aren't seen by the planners?

MR. JESUS: That's correct. It's a tool, so the tool has the overarching envelopes that we're looking to optimize to. But those -- as I indicated how we set those, the planners don't see those numbers. They're busy inputting plans, candidate plans into the system.

And again, as per AMPCO 1, if we turn to AMPCO 1, so I 24, AMPCO 001, we can see in that first table shown there that we had close to -- close to $3.9 billion and in order to get to the optimization, we cut that plan by $717 million, I believe, is the number.

So plans -- the planners are developing candidate plans, the optimization cut the 717 plans and bottom line is they don't see what those envelopes are and they don't use them.

MR. SIDLOFSKY: Could I take you to page 37 of the compendium, please? That's an extract from Exhibit I, tab 3, SEC.4, attachment 2; specifically it's from page 4 of your response to Schools Interrogatory No. 4.

In that excerpt, in the third bullet that we have highlighted here for you, the third bullet from the top of, that bullet states that:

> "Rate base asset growth, originally limited to 4.2 percent as in the previous business plan."

And I believe from what we heard on Friday -- and I don't have it in the compendium, but it's from volume 8, page 51, lines 13 to 19 of the transcript, you indicated that the 4.2 percent applies across the entire enterprise; is that right?

MR. JESUS: That's correct.

MR. SIDLOFSKY: Transmission and distribution?

MR. JESUS: As well as Bruce by Milton, as well as all the remotes, as well as every business that Hydro One Inc. owns.

MR. SIDLOFSKY: Can you explain how the 4.2 percent relates to the financial parameters that you used in the AIP optimizer?

MR. JESUS: There is no direct relationship to the 4.2 percent. As I indicated, the starting position was the

previous business plan that we used to inform the plan.

MR. SIDLOFSKY: Now, the planners may not see the financial parameters, but if there is some pre-defined growth rate or constraint that other people in the organization see, then is the idea that Hydro One has already decided how much money it needs to spend and then the optimizer prioritizes projects and picks them and sort of fills up that bucket until the expenditure limits' been determined -- or been reached?

MS. BRADLEY: I believe the note you have up here, this is our -- is this a briefing to the board? I don't know -- I'm not sure. So this was a briefing to our board of directors?

MR. SIDLOFSKY: I think that's right. I'm sorry, I'm not sure I have the entire interrogatory response here.

MS. BRADLEY: This page looks to me like it came out of one of our board briefings. So if we're briefing our board of directors, every year we have an annual planning process and it would be important for our board of directors to know how this plan compares to the plan that they approved the previous year.

So there when it says the asset-based, asset growth originally limited to 4.2 percent as in the previous business plan, that gives them context so we can talk to what's changed in this plan compared to the last year, and that was reflecting our first -- our first cut of the plan, right, that it was originally limited to.

MR. WOOLF: And I think -- you know, you started off

this line of questioning with respect to the difference between targets and constraints, and I think with your recent question, you asked if we set a goal and we fill it up to achieve that goal.

That's not how the process worked. The way the process has worked is we've identified that the assets require a higher level of investment than our customers can afford. So what we've determined is a constraint that we've had to put on the optimizer to determine the most amount of risk that can be mitigated for the dollars of the constraint.

So there's a difference between target and constraint. We do not set a target with respect to our capital expenditure, but we have set a constraint based on the feedback we've received from our customers around their concern that's around cost.

MR. SIDLOFSKY: Well, just on that point, I'm trying to understand the difference between a target and a constraint.

I think what you are suggesting is that if you didn't have enough projects to meet that constraint or if the projects that your planners had decided were necessary to do didn't total in value to that constraint, then you wouldn't try to meet that constraint; is that the difference between a constraint and a target for you?

MR. BOWNESS: Yeah, so if we went through our first round of investment planning and the bottom-up plan only required $3 billion in investment in the asset needs, we

wouldn't be putting forward anything more than that $3 billion. However, you do see within the evidence that Mr. Jesus put up the initial bottom-up asset need assessment was that there was more work that's required to be done than the constraint allowed for.

MR. SIDLOFSKY: So there was never any question about your needs amounting to less than that constraint.

MR. BOWNESS: Through the last ten years of planning cycles that I've been involved in, our assets have needed more investment than we can afford to spend. So, no, that wasn't a specific conversation that we had at the senior leadership level, because we've been hearing the similar story for plan over plan for a number of years, and as the planners went through their bottom-up exercise, that assumption was validated again that there is more work to be done than we can afford to do.

MR. SIDLOFSKY: I'm going to point you to a couple of other references to the term "available funding", and maybe I could ask you just to comment on those and give your thoughts as to whether that's consistent with your comments about constraints versus targets.

At page 38 of the compendium there is an extract from Undertaking JT2.10. And on the second page of that undertaking, which is actually page 39, at lines 5 to 7 Hydro One states that:

> "The overall portfolio is ranked using the fixed score, and funding is allocated from highest to lowest priority until all available funding has

been allocated."

And just to give you the next one as well, at page 40 of the compendium there is an excerpt from the investment calibration sessions materials that were provided in attachment 1 to Exhibit JT2.9, so that was another one of the responses to technical-conference undertakings.

And at page 13 of 139 in that extract it is stated under "approach to mandatory" -- and that's the category -- that:

> "The remaining projects should then be measured on their strategic value and benefits and ranked for delivery according to available funding."

So again, does that -- when "available funding" is referred to in both of those contexts is that a reflection of your constraint again?

MS. BRADLEY: Yes, that, would be the constraint -- as Mr. Bowness mentioned, we've got more investments than we know is affordable for our customers to be included in the rates, so in doing any prioritization you pick what level of funding you are going to run that scenario on, so it's the funding level that you set as a constraint as you're going through that optimization process.

MR. SIDLOFSKY: Okay. Thanks, Ms. Bradley.

MR. JESUS: I'd also like to clarify when you started this question about page 39, Interrogatory JT2.1, so just to be clear -- Oh. Just so we're clear, the request or the question came from the OEB Staff that talked about optimization versus prioritization, and we're just

explaining what the difference is between optimization and prioritization. That's not to suggest in the first highlighted sentence that you have that we do a ranked order prioritization. We go on to say that we do an optimization, which is a weighted multi-criteria assessment.

MR. SIDLOFSKY: Sorry, a weighted multi-criteria assessment?

MR. JESUS: That's correct.

MR. SIDLOFSKY: Could you just explain that, Mr. Jesus?

MR. JESUS: Certainly. So there's various risk factors that we've mentioned that we've seen the weightings. So we have the variability, the customer, the shareholder, the environment, and so on, and for each one of those risk factors the planners are evaluating the risk associated with each one of those risk elements based on the risk tolerance table that is part of -- part of I24, Staff 089, and we went through previously, so if we want to bring up that table again.

But the -- so Staff 89 in the Appendix, the tables. Keep going. Again, this is the risk tolerance table that the planners would evaluate each one of those risk factors across the top, determine what the risk is, and then from a multi-criteria and the weightings we would evaluate what the total risk is associated with each one of those plans, we would establish what the baseline risk is and what the risk being mitigated is, and that's how we carry out the

process. It would be the difference between the two for the dollars that we are spending.

MR. SIDLOFSKY: So just to make sure I understand, probably Mr. Bowness's comment earlier, there's -- is the constraint similar to a spending envelope?

MR. BOWNESS: Yes, that's a fair characterization.

MR. SIDLOFSKY: Okay. And that constraint is established based on -- well, you've said it's based on your customer's desires?

MR. BOWNESS: It is informed by our customers' needs and preferences. You know, when we look at setting the overall factors associated with optimization, there is discussions with our board of directors, with our senior leadership around determining the risk factors that we have that to go into the optimization. We also make sure that we consider the direct customer feedback, and we know that customers are very concerned about rates, and our board of directors and our senior leadership is also very concerned about rates, so we have put forward here the best plan that we can within that envelope of dollars that we believe is prudent with respect to what our customers need to pay for the upcoming period.

MR. SIDLOFSKY: While maintaining reliability status quo?

MR. BOWNESS: With the initial target of maintaining reliability, and as I spoke to before the break, the subsequent improved reliability that we're targeting with our vegetation management program for the as-submitted

dollars.

MR. SIDLOFSKY: Okay. I'm going to move on to another area specifically related to project deferrals.

What's the basis for classifying projects as non-discretionary?

MR. JESUS: So non-discretionary are projects that are mandatory in nature; i.e., required for compliance that are -- that occur year after year, such as trouble calls, demand programmes, break/fix programs, new connections, system access, all of the connections, the work that's required under the Distribution System Code, all of those, as well as even IT projects where we have systems to manage on a regular basis, and Mr. Lincoln will be talking about that, but there are certain investments required to sustain those systems.

Everything else, from a -- when we say discretionary spend, it's about, okay, so which projects are we actually going to do from a stations point of view. Although we call it discretionary, there are 70 poor-condition stations, and the question is how much money are we going to allocate to those stations. That is still considered discretionary.

MR. SIDLOFSKY: Is it fair to say that a significant portion of your forecast capital spending is non-discretionary?

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: And thinking in particular about system renewal projects, can you give a sense of which of

those projects would be non-discretionary or non-deferrable?

MS. GARZOUZI: Trouble calls would be a good example.

MR. SIDLOFSKY: Trouble calls are an ongoing issue. I mean, they come up as they come up.

But do you have any projects that you've proposed currently for system renewal that are holdovers from your last cost-of-service application?

MS. GARZOUZI: The PCB program for the pole top transformers specifically would be a good example of that to comply with the federal legislation.

MR. SIDLOFSKY: Were those considered non-discretionary or non-deferrable in that filing?

MS. GARZOUZI: So I would distinguish non-discretionary and then deferrable separately. And the reason I'm just separating deferrable is just by when. So for the PCB legislation is by 2025, so there is some time to meet that time line, whereas a trouble call -- you know, the pole is down, or the line is down, the customer is out of power, so we respond immediately. So there's two components to this.

MR. SIDLOFSKY: Have you ever repeatedly deferred projects that you've considered to be non-deferrable?

MS. GARZOUZI: If we considered them non-deferrable, then they would get done.

[Witness panel confers]

MR. SIDLOFSKY: Sorry, was there more to that answer?

MS. GARZOUZI: I'm just distinguishing again between

discretionary, non-discretionary, deferrable and non-deferrable. I think there's just two elements to the conversation.

MR. SIDLOFSKY: Okay. Could we go to pages 41 and 42 of the compendium? In that extract from day 6 of the hearing -- and that's from pages 136 and 137 of the transcript for day 6 -- Mr. Rubenstein and this panel discuss what was accomplished in terms of sustaining capital programs. In the current application, those are system renewal projects compared to the planned investments between 2014 and 2017.

And in that discussion, you confirmed that Hydro One undertook fewer transformer replacements, fewer station refurbishments, fewer pole replacements, fewer PCB line replacements, and fewer large sustaining initiatives than originally planned.

I know you mentioned the pole top transformers before, but I'd like to just touch on a number of examples of those investments in a bit more detail. At pages 43 to 47 of the compendium, we have a discussion about station refurbishment, ISD number SR-06. Historically, that was project S7.

So the ISD for station refurbishment project S7 is included in the compendium at pages 43 through 47, and that's from Hydro One's previous application, EB-2013-0416, Exhibit D2.2.3, reference number S07, and the station refurbishments planned over the five-year period were listed at pages 44 to 46 of the compendium.

So just in looking at that, would you agree that between 2015 and 2016, Hydro One had planned to refurbish a total of 74 stations in that application?

I would be happy if you took that to subject to check, because I don't need you to count it right now.

MS. GARZOUZI: Subject to check, yes.

MR. SIDLOFSKY: If we turn to Staff Interrogatory 159 starting at page 48 of the compendium, and that's from Exhibit I, tab 26, Staff 159 in the current proceeding, there is a list of stations refurbished in the last three years. That's provided in response to part E on page 51 of the compendium.

Based on that list, I'm seeing only 40 of the 74 originally listed stations that were refurbished, correct?

MS. GARZOUZI: That's correct. That's in the planned program fashion. In addition to those, some transformers or stations were addressed via unplanned, and so we did experience additional failures over the planning period, and so the risk mitigated was addressed for those stations. But from a planned to planned program, that's correct.

And the reason for that, as we discussed earlier, was the assumption for the unit cost of the distribution station. The assumption was that we can do a distribution station refurbishment for $1 million using the IMDS, which was a new and innovative approach at the time.

That assumption was incorrect, and so we did spend our capital budget, but we accomplished less units from a planned perspective.

MR. SIDLOFSKY: Okay. Now, category SR-12, that's distribution line sustainment, and my understanding is that historically that was -- that was project S-12.

Staff have included the ISD for project S-12, line sustainment initiatives at pages 63 through 67 of the compendium. That comes from Exhibit D2.2.3, reference number S-12 of your previous cost-of-service application, EB-2013-0416.

And at pages 3 to 4 of that ISD, you listed the line sustainment initiatives planned over the five-year period for your proposed custom IR period. And at that point, I'm seeing 33 planned line sustainment initiatives above a million dollars and that was -- sorry, that was 2015 to 2017. Again, I'll take that subject to check.

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: And if we look at your current application, ISD SR-12, which we've reproduced at page 68 of the compendium, there is a list of planned line sustainment initiatives and it appears that 18 of the 33 originally listed projects are repeated in this application.

Would you say that's correct?

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: Another category, the system -- excuse me, category SS-02, system upgrades driven by load growth and historically that was project D-02.

We've reproduced the ISD from your 2013 application for category D-02, system upgrades driven by load growth.

That's at pages 88 through 93 of the compendium. And your planned projects are listed on pages 3 to 5 of the ISD, and is it appears that between 2015 and 2017, you had planned 36 system upgrade projects above a million dollars.

Is that correct, subject to check?

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: And moving along to page 94 of the compendium, we've got the ISD SS-02 from your current application. There is a list of planned system upgrade projects at page 101 of the compendium.

Based on the that list, it looks like 14 of the 36 originally listed projects are repeated in this application; is that correct?

MS. GARZOUZI: That's correct. What you are seeing in this table, so it was the combination of SEC.42 and SEC.52 is really the shifting of dollars between projects -- sustaining in particular, or system renewal.

So if we look at just those categories, it is true that some projects are repeated and that's because they were deferred so that other things could occur. Specifically, trouble calls for the period '15 to '17 were much higher than planned. And so starting with that, money is redirected to that program, hence we're taking away from large sustainment and other programs and projects within the sustaining category.

So the pole replacement program is the largest one in the category, which was 92 or 91 percent accomplished, 86 percent spend. The next one in that same table is the

trouble call, which is, again, in the $250 million range for the three-year period, and then it drops significantly after that to around $100 million for large sustainment station refurbishment, and then the line components and the PCB and the MUS and all of those are, you know, below $50 million.

And so shifting to trouble calls has a significant impact on the other smaller capital programs within the sustaining envelope.

MS. BRADLEY: The one thing I -- if you look at the trouble calls in the list that was provided last week, trouble calls and storm damage were $66 million over in the three-year period. We don't have the option of just leaving customers out of power. We connect them, so that envelope was over.

If you look on the screen right now, it takes a lot of these projects to be deferred to make up that $66 million.

MR. SIDLOFSKY: So it's really a matter of -- sorry, the carry-over projects really resolve from items that -- capital items that were completed -- sorry, that weren't completed because capital had to be redirected to higher-priority projects; is that right?

MS. GARZOUZI: That's correct.

MR. SIDLOFSKY: Now, at page 116 of the compendium, we've reproduced Exhibit I, tab 23, Staff 84, and in your response to part C of Staff Interrogatory 84 you explain that the process of assessing the need to redirect capital happens on annual basis, correct?

MS. GARZOUZI: So redirection is actually an activity that occurs monthly. So we look at our programs and projects for OM&A, ISA, and capital on a monthly basis, and we look at emerging needs, if they do exist, and we reprioritize via the redirection process.

MR. SIDLOFSKY: Are you able to correlate the projects that I mentioned that were deferred to particular reasons for the redirection of funds?

MS. BRADLEY: Redirection doesn't happen on a project-by-project sort of swap basis. We meet monthly and talk about the number of factors that result in changes each month. It could be changes due to storm activity. It could be changes due to customer needs have changed. It could be a project is being deferred for a reason, you know, customers might not want it in-service at the time. We could have had some environmental factors that led to a delay.

So we talk about things that are changing, both adding more needs to the system or the year's budget or plan, and we talk about things that are reducing, so we might have less of something needed because of changes in conditions as well.

So it's not like you say, I need to do this project so let's defer this project; we talk about the budget as a whole and the envelope of work and the impact on outcomes as a whole, and make those decisions on a monthly basis.

MR. BOWNESS: And the feed-in to that is the process that my team executes on are monthly basis to update

forecast based on actuals. You know, an example that I think we spoke to a few days ago was, you know, this year with the two major storms that we had around the 500,000 customer mark. Those were $40 million worth of storms. Our storm budget for the whole year is $65 million.

So we're currently going through a process of looking at which other program line items can be deferred this year out into future years. And that's the type of process we go through on a monthly basis.

DR. ELSAYED: Can I ask: Who approves these changes? When you make changes at the project level, who approves that?

MR. BOWNESS: We go through a process that is facilitated by Ms. Bradley's planning group on a monthly basis with vice-presidents and directors across the company to review the results. The summary of that is then presented to our executive leadership team, which involves our C level executives, with a summary of any major changes that we would have within the program.

DR. ELSAYED: So that is formally approved with a -- monthly?

MS. BRADLEY: Yeah, each individual project change is approved by the person with accountability for that program. So if we were removing something I'd have to be -- I have to be able to approve a project and the outcomes associated with deferring it, for example. But it is reviewed and it's approved monthly, and the summary of the changes, in terms of financial changes, accomplishment

changes, and impact on outcomes is taken to our executive leadership team on a monthly basis.

DR. ELSAYED: Thank you.

MR. SIDLOFSKY: All right. Now, since the projects that we discussed as having been deferred from the last application were all included in your most recent previous application, they must have made it to the prioritized list of projects when you were developing your capital plan for your last application, correct?

MS. GARZOUZI: That's correct.

MR. SIDLOFSKY: So presumably those projects needed to be completed to meet your reliability targets in your last application? Am I right? Otherwise they wouldn't have made your list?

MS. GARZOUZI: Yeah, a combination of depending what project we're talking about, there might be different drivers, so that PCB is not a reliability example, it's an environmental legislation example. Some of the system renewals are, you know, condition-based failures, so those would be correlated to reliability, so it really depends on the project that was deferred.

MR. SIDLOFSKY: Can you tell me if there were any negative consequences to reliability associated with those deferrals?

[Witness panel confers]

MR. SIDLOFSKY: Maybe it's fairer to ask you if you actually identified any negative consequences to reliability.

MR. BOWNESS: If you look at item-by-item impacts, so if you think -- you know, we accomplished 92 percent of the pole replacement program. Out of the 8 percent that we didn't accomplish, did that have a negative impact on a reliability performance? Potentially. Do we trace everything down to every single pole and every outage and what was the impact on SAIDI? No. That's not how we look at it. We look at it at the aggregate.

But if you do look at our reliability performance last year, as an example, within SEC 29 we had a target last year of 7.5 hours as our objective for the year. We missed the objective. We failed. We came in at 7.95, and the primary reason for that last year was a much higher volume of tree-related outages. We had over 45 percent of outages last year were tree-caused.

So this is something that we look at on a more system basis. We look at tree-caused outages causing a more macro impact on SAIDI, and we are doing something about it.

So I would think that, you know, if you are trying to look at, this pole was deferred and therefore it was this impact on SAIDI, we don't track things to that level of granularity. We look at it on a much more macro basis.

But within the redirection process we are trying to make the best decisions as we can within the envelope of funds that we have. You know, when we have the example scenario from the last few weeks of the incremental storm costs, you know, we recognize that that's going to have an impact likely on our pole replacement volumes and our

investments in worst-performing feeders this year; but it is an item that is out of our control, and it is an item that rolls up within our overall capital envelope, and we have to shift dollars out in -- or we have to shift work out into future years to deal with that external factor of two very extreme weather events.

MR. SIDLOFSKY: But you determined -- and I understand what you are saying about overall impacts on reliability, but you found that you were able to defer these projects for upwards -- in some cases, upwards of five years.

Are there any compelling reasons why some of those previously deferred projects couldn't continue to be deferred? Has their status changed somehow or, you know, is what you felt was -- what you felt was important at the time you established your plans for the past cost of capital -- or capital investment period, has it become more urgent to do those projects? Is there some reason they couldn't be deferred?

MR. BOWNESS: So I think what we need to look at is we need to look at the rolling nature of the deferrals. So when we have something that's redirected out of this calendar year, we target to do it is a early as possible the following calendar year. And yes, that's going to push something out that's in the last quarter of next calendar year, out into the first quarter of the following calendar year.

So by deferring something, it's not necessarily taking it and moving it out five years; it's about rolling it

ahead into a future one-year plan.

If you look at the items that are within this distribution station scenario, the items that were in the 2015, '16, '17 period would have a high probability, and subject to check, of things that we're doing within 2018 and 2019. So it's not that they are far beyond the delivery period; it is within a year or two of when we want to do it, and that's the basis of the decisions that we have when we go into redirection.

There are some scenarios, though, when we get into redirection and we say, you know what, we just can't afford to push that work out into future years. And that's where we have to make a conscious decision as to whether we will need to go over our capital envelope and then we will need to come in to true-up and secure that over-allotment in future submissions.

But we really try to work within our means and manage within our means as best we can.

MR. SIDLOFSKY: Could I take you back to page 16 of the compendium? That's an extract from Exhibit B1-1-1, section 3.7 of your DSP, and if we look at the forecast capital associated with the number of drivers -- and I'm just going to list them: SR-06, stationary refurbishment, we spoke about a bit about that a bit before. SR-08, PCB equipment replacement, SR-12, distribution line sustainment, also something we touched on earlier. SR-13, life cycle optimization. SS-02, system upgrades driven by load growth; we also touch on that one. And finally, SS-

03, reliability improvements.

When I look at those half dozen investments -- those -- just those six drivers appear to account for about 20 percent of your overall capital expenditure for the next five years. And I take it, subject to check, that the total expenditure of those six drivers for the five-year test period -- the five-year plan period is $730 million, approximately.

So the way I got my 20 percent was 730 million of a total of 3.6 -- sorry, 3,676,000,000 in total capital investments.

Can we agree on that, subject to check?

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: Each of those categories of expenditures include carry-over projects from your previous filing. Is that right, Ms. Garzouzi?

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: And it appears that on average, or is it -- I'll ask you if it's fair to say that on average, about 40 percent of the projects in those categories were redirected in favour of other investments?

MR. BOWNESS: I would characterize it that they were redirected due to external factors that were beyond our control, such as weather and an increase in trouble calls, as well as an external factor with Bell making the CDMA network obsolete.

MR. SIDLOFSKY: But the 40 percent figure is accurate?

MS. GARZOUZI: Subject to check.

MR. SIDLOFSKY: Okay. My last question on that area is whether Hydro One has benchmarked itself at all against other utilities to consider whether that's -- to determine, first of all, the typical level of redirection of funds for unforeseen circumstances, and second, how you compare to that among other utilities?

[Witness panel confers]

MS. GARZOUZI: We have not, but just given the nature of the distribution business and given the fact that a lot of investments are non-discretionary, inevitably the ones that have flexibility as to when you would service them will be deferred and that's what you're seeing here.

MR. BOWNESS: But I would also say macro-ly, if we are talking about 20 percent of the portfolio and 40 percent of it has an element of redirection, we are talking about 8 percent of the portfolio.

And we haven't done any official benchmarks, but to have 8 to 10 percent variability is not something that I consider an extreme amount of variability, knowing the complex nature of the system and the external factors that our company and system face on annual basis.

MR. SIDLOFSKY: Thank you. I'm going to move on to another area related to business cases.

So I'd like to focus on the planning process associated with two specific ISDs, SR-06 and SR-09, and I've chosen those because they -- excuse me, they seem to comprise a significant proportion of your system renewal capital spending under plan B modified.

So I'd like to take you to page 121 of the compendium, and that's an extract from the March 2nd session of the technical conference, specifically page 47 of the transcript.

And at lines 8 to 12, Hydro One states:

> "The analysis that goes into determining how many poles and how many whatever else we're doing from a program point of view is developed by the planners and then bundled into the program. It is a recurring expenditure and no business case exists, other than the ISD."

Is that accurate?

MS. GARZOUZI: For programs, that's correct.

MR. SIDLOFSKY: So that statement suggests that the number of poles planned for replacement is developed by the planners, without preparing a business case to demonstrate that the number of pole replacements has been economically optimized. Am I right?

[Witness panel confers]

MS. BRADLEY: The number of poles to be replaced are put into the optimization tool and they are optimized in terms of risk and benefit. And while there isn't a business case prepared, in the materials we've submitted that went to our board of directors, we did go through an outline of the plan A, B, C, and B modified and how many poles that would replace and on and how that would leave the condition of our fleet would be in at the end.

So it is done on a bottom-up basis through the

optimization planning process and the planning process, and it is reviewed with our board of directors as far as an approval of that strategy.

MR. SIDLOFSKY: And pole replacement, as we've discussed at some length, is a large investment category and it's expected to grow rapidly over your forecast period, correct?

MS. GARZOUZI: What you see in SR-09, the net investment line, is what we're seeking here to achieve the 72,000 poles, so what you see in 18 is the compression to keep rates low or to manage the rate impact, and then you see it jump back in 2019 and increase steadily over the planning period from 2018 to 2022.

MR. SIDLOFSKY: Maybe just to make it a bit clearer I'll take you to page 17 of the compendium, and for pole replacements, SR-09, I think this is what you were referring to, right, Mrs. Garzouzi?

MS. GARZOUZI: That's correct.

MR. SIDLOFSKY: So we are seeing a 52 percent increase in costs between 2018 and 2019, and then when we look at 2019 to '20 that's another 14 percent increase in costs, correct?

MS. GARZOUZI: So this matches the units, so 2018, we're targeting to do 9,600 units, which is again artificially low on purpose to manage the rate impact for the year '18, and then we increase to what we believe is a more sustainable, manageable level, given the amount of wood poles we have that are in poor condition.

MR. SIDLOFSKY: Okay. If we go to page 122 of the compendium, Staff have reproduced an excerpt from the Navigant benchmarking study, specifically from Exhibit B1, tab 1, Schedule 1, section 1.6, attachment 1, page 16 of 33. One of the observations by Navigant -- and you will recall this one -- was that:

> "The cost of replacing a pole is substantially higher than the cost to refurbish a pole, with replacement being approximately seven times more expensive where refurbishment is an option."

At the time you were creating capital budgets, were you aware of that cost differential between refurbishment and replacement?

MS. GARZOUZI: I think the cost differential has to be put into context, so chemical refurbishment of poles extends the life of poles, but that is a pole that has not failed, so it's not in poor condition, so it would extend the life of the pole.

Mechanical refurbishment can extend the life of a pole, and Mr. Buckstaff spoke about that with you at length, and again, there are elements that may contribute to how long it can extend the life or the age of that pole, and so when we look at the poles that we've identified in poor condition, I don't know that a lot of them are good candidates. I gave the number 10,000. I think that 10,000 of them may be good candidates for refurbishment, but the remainder not so much.

And so to answer your question, you know, did we

consider refurbishment as part of the capital plan, certainly we did have the benchmarking findings, and it is something that we're exploring, and that may help us manage the life cycle of the wood-pole population and hopefully extend the life of wood poles even further, but for the ones that were found, I still think they need to be addressed.

MS. BRADLEY: So we also were really focusing on containing and reducing the OM&A spend for this application, so refurbishment, the chemical treatment Ms. Garzouzi spoke of, it won't address the end-of-life poles we have. so that capital spend would remain in our program. We could, for future applications, look at adding an OM&A program in addition to the end-of-life program to do this kind of treatment in our program, but that would not deal with the end-of-life fleet; it would just be an additional cost and an additional program to help that fleet that we are going to be dealing with 30 years from now.

MR. SIDLOFSKY: So just to make sure I understand then, even knowing about the cost differential now, that's -- you don't see that as having any impact on the next five years of your capital planning?

MS. BRADLEY: It could add to the cost of the next five years through doing a treatment that would help them last longer 30 years from today. It will not address the poles that we're replacing due to end of life.

MR. SIDLOFSKY: Okay. I think that's the point I'm

trying to get to, that your end-of-life poles wouldn't even be considered for refurbishment; is that your conclusion?

MR. BOWNESS: So as Ms. Garzouzi spoke to, within the 72,000 that we have, we believe that there is a portion of those that could potentially benefit from refurbishment, and we're looking at that. But we also have to remember we have another population of 100,000 poor-condition poles that we are not able to get to, so if some of the existing pole population, the 72,000, can be injected, braced, et cetera, what we would do is we would reinvest the pole replacement dollars in the pool of the other hundred thousand poor-condition poles that will need to be replaced.

MR. SIDLOFSKY: So if Ms. Garzouzi's estimate of 10,000 poles that might benefit from refurbishment is correct, with refurbishing 10,000 out of 72,000 poles, I take it then that you don't see that as -- you don't see that representing a cost savings, you would simply reallocate your capital to other -- to additional poles; is that right?

MS. GARZOUZI: I think the main point is that we are doing less poles than we have in poor condition, right? So if it was proven to be cost-effective and it's a practice that we are willing to introduce, then for those we would redirect the funding to address that subset of poles.

MR. BOWNESS: I think macro-ly, you know, we talked about, at the end of this planning period we still have 99,000 poles that are in poor condition, so if we add the

ones we're replacing and what's going to be remaining in the backlog, we have a pool of about 171,000 poles. We are going to replace 72,000 of those within this plan, and we are also investigating whether there's some cost/benefit with respect to refurbishment, but this is an incremental cost, right? This is OM&A dollars. So if we determine there's good value for the money on the OM&A side, we will need to look to redirect away from other OM&A items in order to fund this, but that's the type of analysis that we'll do within the planning period as to the best business decision we can make with the information that's available at the time.

MR. QUESNELLE: Mr. Bowness, is it your understanding that the cohort that was looked at for comparisons in the Navigant study, that other utilities are expensing the refurbishment? It is not an extension of life, therefore a capital investment?

MS. GARZOUZI: It is an expense, I believe, so it's OM&A.

MR. QUESNELLE: Thank you.

MR. SIDLOFSKY: I just want to clarify a couple numbers about pole replacements -- or about your pole replacement program.

First of all, we've already discussed your approach to pole replacement, and that is to replace poles classified as being in poor condition based on actual condition assessments, as well as the red pine poles; is that right?

And the rate -- and it's the red pine poles because

they don't meet treatment standards; correct?

MS. GARZOUZI: That's correct.

MR. SIDLOFSKY: And from Volume 8 of the transcript -- and I don't have this in the compendium, but on page 80, lines 12 to 13, Ms. Garzouzi, you explained that 4 percent of Hydro One's 1.6 million wood poles are in poor condition, and that figure comes from Exhibit I24, AMPCO 23?

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: And that would be 64,000 poles, but on page 87 of the transcript you clarify that there are actually 67,000 poles? I just want to know what the correct number is.

MS. GARZOUZI: Yes, 4 percent of that population, so it is rounded at 4 percent, so that's the difference that you're seeing.

MR. SIDLOFSKY: So what's the right number, 67 or --

MS. GARZOUZI: 67,000.

MR. SIDLOFSKY: 67,000?

MS. GARZOUZI: Yes, 67,000.

MR. SIDLOFSKY: Yes. And you explain that 39,000 red pine poles don't meet the CSA standards for penetration and retention of treatment?

MS. GARZOUZI: That's correct.

MR. SIDLOFSKY: And Mr. Bowness, you explained a little bit later on page 91 of the transcript that about 20 percent or 7,000 of the 39,000 red pine poles are estimated to be in poor condition?

MR. BOWNESS: So I think after the break, we clarified the breakdown of the total pole population as in the evidence of SR-09, where I think we brought clarity as to the total number of existing poles and the future projection on additional poles.

MR. SIDLOFSKY: Okay. And just to confirm, the CSA standard that you are referring to, does that require that poles that don't meet the standard have to be replaced?

MS. GARZOUZI: The CSA standard is a treatment standard of poles that measure their retention and penetration of chemical treatment to preserve the wood pole.

If I may add, in a previous proceeding, we did third-party independent assessment of the subset of red pine and it was found that -- the recommendation was that these poles should be proactively replaced.

MR. SIDLOFSKY: But the standard doesn't require replacement? That was your determination, that the poles should be replaced?

MS. GARZOUZI: It was our determination with the help of a third-party.

MR. SIDLOFSKY: Is there a report from a third-party?

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: Is it on the record?

MS. GARZOUZI: Yes, it was filed.

MR. SIDLOFSKY: Okay.

MS. GARZOUZI: I can give you the reference at the break.

MR. SIDLOFSKY: Sure. On page 164 of the transcript, lines 13 and 14, Ms. Garzouzi, you had an exchange with Mr. Brett and you said that 12,000 additional poles are replaced each year for other reasons. So that would be about 30,000 -- excuse me, about 60,000 poles over the forecast period, correct?

MS. GARZOUZI: That's correct.

MR. SIDLOFSKY: And the cost of those additional pole replacements, those would be under various other programs, am I right?

I will list a few here and maybe you can confirm them. SA-01, joint use and line relocations.

MS. GARZOUZI: That's correct.

MR. SIDLOFSKY: SR-07, distribution line trouble calls and storm damage.

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: SR-12, distribution line sustainment.

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: SR-13, life cycle operational efficiency.

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: And SS-02, system upgrades.

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: And SS-06, worst performing feeders.

MS. GARZOUZI: Not that one, but the other ones, yes.

MR. SIDLOFSKY: And would you expect poles that are in poor condition to be among the first to fail during storms?

MS. GARZOUZI: I would say that given this -- you

know, normal wind, yes, they are more susceptible to failure than a pole that has its remaining strength.

MR. BOWNESS: We do see lots of circumstances where new poles will fail. Micro busts of wind, severe weather, icing of lines, wind sheer, during that trees falling on lines on poles. We do see poles that are not at end of life failing during storms.

MS. GARZOUZI: And that would probably include fair condition poles as well, is that right?

MS. GARZOUZI: That's correct.

MR. SIDLOFSKY: So the poles that would be replaced under those other programs are in addition to the 72,000 you are planning to replace under SR-09?

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: Any way to estimate how many poor condition poles would be replaced under other programs?

MS. GARZOUZI: We assume the poor condition population when we project forward, when we conduct analysis and we look at just the population of wood poles, we assume that that same percentage is applicable on the other programs.

Again, there is no way of knowing for sure. You can have all new poles fail during a storm, but it's an assumption that we make when we try to analyze the program.

MR. BOWNESS: I think if we're talking about 12,000 poles a year against a population of 1.6 million, it is less than a percent of poles. So you are getting down to a percentage of less than 1 percent.

MR. SIDLOFSKY: Okay. Moving over to station

refurbishments, SR-06, and I'm going to take you to page 17 of the compendium, that also seems to be a fairly rapidly growing category of capital investments.

You're projecting an increase of about 97 percent -- about 97 percent between 2018 and '19, and a 14 percent increase in cost between 2019 and '20. Have you done any analysis to -- that would demonstrate that the proposed size and growth trajectory of that program is economically and technically optimal?

MS. GARZOUZI: We're looking at SR -- you're looking at SR-06, correct?

MR. SIDLOFSKY: That's right.

MS. GARZOUZI: Okay. So that is actually a reduction from historical, and so the anomaly here is actually 2018 and it's again to manage the rate impact. We are planning to address stations that are in poor condition based on our tests, furan tests, DGA, so on and so forth.

And so it's -- I don't view that as a jump. I think the anomaly is that '18 is artificially low and the other years are sustaining the poor condition stations and transformers.

MR. SIDLOFSKY: And 2018 is artificially low? Why?

MR. BOWNESS: One of the items that we looked at when we went through the process of plan B versus plan B modified was how we could move certain investments out into later years to minimize rate impacts in the early years. So it is purely a timing aspect with respect to taking our customer's feedback and our board's feedback around

minimizing rate impacts for the capital investments.

MR. SIDLOFSKY: Staying on station refurbishments, back on day 6 of the hearing -- and I can point you to pages 118 to 120 of the compendium -- Mr. Buckstaff and I had a discussion about cost estimate precision for station refurbishments. And Mr. Buckstaff had explained that cost estimates for station refurbishments are generally done in three stages.

So you have the initial stage, which is a rough estimate that could be plus or minus 30 percent. The preliminary engineering stage, which is an estimate with a greater precision than plus or minus 30, and finally the construction stage where you've got very detailed cost estimates.

Do you recall that conversation, or are you familiar with it?

MR. BOWNESS: Yes, I'm familiar with that conversation.

MR. SIDLOFSKY: Okay. Now at the time Hydro One was building its capital budgets, had Hydro One completed preliminary engineering for any of its planned station refurbishments?

MR. BOWNESS: I think there’s a few things at play here. One is historically we took a much more unit cost approach with our station investments, and if you look at the evidence that Ms. Garzouzi spoke to, we had planned to get the IMDS station refurbs down to a million and we had some historic actuals on unit cost.

We've moved over the last number of years to a more refined process on estimating our stations refurbs and going through a similar stage gate process that we do with our TX capital projects.

So I can't definitively speak to, as the evidence was submitted, how many of those projects would have gone through a preliminary engineering versus the detailed engineering spec. But what I can say is that items that are currently within the 12- to 18-month horizon from an execution perspective are going through that stage, and the items that are beyond 18 months would still be in there based on their planner's estimate.

MR. SIDLOFSKY: So if you are not at that stage of preliminary engineering how did you come up with the estimates for station refurbishments?

MR. BOWNESS: So we used the planner's estimate, which is based on historical costs, in order to project the average cost associated with implementing a station refurb, multiplied by the number of station refurbs, but we do anticipate after we get through detailed engineering and scoping and detailed estimating that we will have some variability within that, because a planner's estimate is plus or minus 50 percent.

MR. SIDLOFSKY: And are all your station refurbishments like-for-like replacements? I guess what I'm trying to get at there is, if you are basing your estimates on historical information --

MR. BOWNESS: Historical projects which would have

some variability of small changes as compared to the legacy infrastructure that are being changed. You know, a lot of these stations were built 50 years ago, so like-for-like from a capacity perspective, yes, but not like-for-like from a technology perspective, but if you look at -- we're using actuals from the previous handful of years, so that's a good reflection on the scope and the solution of what we'll be implementing in the next five years.

MS. BRADLEY: To go through a Class A estimate say seven years in advance to facilitate a five-year application would contain a lot of risks around, you know, the environmental conditions at the time, the real-estate conditions at the time. You would have to carry the costs associated with preparation of that estimate and potentially acquisition of land and rights to move lines or facilities, so we try to do that estimating in a time where the conditions are going to be similar and reflective of when we built and where we're not going to carry the costs associated with doing enough work to give a plus or minus 10 percent estimate. You don't want to carry those costs for five to seven years before you intend to put a shovel in the ground or build a project.

MR. SIDLOFSKY: Okay, and your intention is to maintain the number of stations in poor condition at 70, correct, under Plan B modified?

MS. GARZOUZI: That's correct.

MR. SIDLOFSKY: So you've identified the number of stations that will be moving into that poor-condition

category over the next five years?

MS. GARZOUZI: We've estimated the number, but we didn't identify them, because they have not moved there yet. So we know what is in poor condition today. Those are the 70 stations, and so we will address those. We are estimating that we will find about 70 over the plan. We don't know which ones they will be.

MR. SIDLOFSKY: So you wouldn't have scopes for all the projects you are going to perform over the next five years; is that right?

MS. GARZOUZI: No, so we know which stations are in poor condition right now. Those are the ones that are in the plan. Those are the ones that we want to address through this five-year plan. And so we're quite familiar with these sites. We --

MR. SIDLOFSKY: But -- sorry, go ahead.

MS. GARZOUZI: But we have not completed detailed engineering for all those sites.

MR. SIDLOFSKY: Okay, but you do have the sites identified at this point?

MS. GARZOUZI: Yes.

MR. SIDLOFSKY: Are you confident that the level of expenditures that you have proposed will allow you to keep pace with the stations that are in poor condition?

MS. GARZOUZI: I find it quite low, actually. I think that it's a skinny plan for stations, if I may. So I think it's a bare minimum to keep the condition of the stations to what it is today.

MR. BOWNESS: But we do have a high level of confidence that the estimates that are in the plan of approximately -- approximately $2 million per station is a good reflection on the average scope and solution and cost that it's going to take to replace those. Historically, as we mentioned in the last rate filing, we had hoped that the IMDS solution was going to result in a million dollars per station refurb, but we have gotten better information around that being not feasible and not as feasible in many situations, so we believe that the 2 million average unit cost going forward is appropriate.

DR. ELSAYED: Can I just clarify? When you say "level of confidence", just what level of confidence do you have on both the estimate that you have for these projects as well as the outcome? I just want to make sure I understand your response to Mr. Sidlofsky's question. Do you have a high level of confidence that you can execute these projects within that estimate?

MR. BOWNESS: I have a high level of confidence for the projects in the next 12 to 18 months. The ones that are further out, we may run into situations where we have more complex environmental needs based on the sites, different engineering requirements, so there's less confidence in those future years, but in aggregate across the overall portfolio I have confidence that the average unit cost is appropriate.

DR. ELSAYED: Less confidence in the cost but also is it less confidence in the scope of the work?

MR. BOWNESS: Yes, so we've done condition assessments and we know that there is work that needs to be done, but until we do the detailed engineering it is hard to, you know, say I have a 98 percent confidence in the solution. Once we complete the detailed engineering and we have our estimate at that point, that confidence level gets into the high 90 percentage range.

MR. SIDLOFSKY: Mr. Quesnelle, I'm looking at the schedule for today, and I think the Board had anticipated a lunch break at 12:20. I am about to move to one other brief area, but I also have some follow-up questions from -- that have been referred to this panel by other panels. That's going to take a little more time. I may be about 20 minutes over my two hours. I'm in your hands about when you'd like to take the break, but I am moving on to another area.

MR. QUESNELLE: I think I actually prefer -- I think the lunch break was leaving quite a large amount of time for the afternoon, so why don't you carry on, Mr. Sidlofsky, and we'll see if we can finish up with this panel.

MR. SIDLOFSKY: Great. Thank you.

MR. QUESNELLE: I hope that doesn't interfere with anybody's pre-set plans, but... Okay.

MR. SIDLOFSKY: Panel, could I take you to page 125 of the compendium. That's an extract from the March 2nd session of the technical conference, specifically page 43, and in that excerpt Hydro One explained that the Copperleaf

tool is used to develop a portfolio of prioritized projects, and you also advised that:

> "Subsequent to risk assessment and investment optimization processes a calibration session is held where Hydro One management is able to override the portfolio of optimized projects developed using the comp relief tool."

And on page 43 of the transcript at lines 22 to 25 Mr. Jesus says that:

> "The calibration session is where we engage all of our enterprise and we come to the meeting and we challenge the risk assessments that were provided during the candidate development."

How does Hydro One ensure that the Copperleaf tool is populated, set up, and utilized properly?

MR. JESUS: So this calibration session is where we bring in the entire enterprise as noted there in the transcript, and it's about level-setting the risk assessments to make -- to ensure that one group isn't exaggerating the risks, so each group would take the entire enterprise through their risk assessments, and we would challenge each one of the groups on their risk assessments that they've carried out, with the purpose being to level-set the risk assessments across the entire enterprise so that we are -- we're being extremely objective about the risk assessments and challenging people in terms of their assessments.

MS. BRADLEY: That's a process that enhances the other

QA aspects of the investment planning process. Like, there are a number of quality assurance measures in place in addition to this risk calibration.

MR. SIDLOFSKY: So it sounds, though, like the calibration sessions are held not because -- they are held in order to balance the expectation of the planners working on your capital project; is that right? Or is it -- are you adjusting the tool because -- or, excuse me, are you adjusting the output of the tool, because the tool doesn't adequately evaluate the technical and financial parameters that you need to develop the portfolio?

MS. BRADLEY: This is actually an enhancement to our process to bring people that are planning for different types of work together to talk about how they've characterized risk and make sure it's comparable.

It doesn't relate to the financial aspects of the tool; this is risk. If I have a project and I've characterized an environmental risk, does that compare similarly to how somebody in fleet has characterized environmental risk, or somebody in our health, safety and environment group.

So it is really just across different types of spend. Sometimes you can look at those reliability or environmental factors that are coming from a different lens, and it's just to level set with the vice-presidents and directors to make sure we agree that they're all similarly weighed o factored into the investment risk assessment.

MR. SIDLOFSKY: So did the project portfolio that you've filed reflect a significant modification from what the Copperleaf tool produced?

MS. BRADLEY: I wouldn't categorize the final plan as significantly different. The changes that would be made were, say, to reduce the 2018 spend. That wouldn't have been in the tool. We would have had to manually say, okay, we're going to reduce in these areas.

Other changes that could be made is an update on projects that are in flight. So we might have had a project we thought was going to be put in-service before the end of 2017, and in October or November, we find it's not going to be 2017, it's going to be 2018, changing the in-service additions in 2018.

So those sorts of adjustments are made kind of outside the optimization in the tool, but the vast majority is consistent with what the prioritization process does as far as the risk value curve.

MR. SIDLOFSKY: Can you think of any material examples of priorities that were changed through the process that -- through the calibration sessions?

MS. BRADLEY: The calibration sessions take place before we prioritize the plan. Like before we optimize at all, the planners input the needs, they input their risk assessment. Before we ever go through the optimization process, we level set on ensuring that the risks have been captured consistently across the businesses.

So I couldn't answer that. We don't optimize it

before that process.

MR. SIDLOFSKY: Okay. Could I take you to page 35 of the compendium, please? And that's your response to exhibit -- part of your response to Exhibit I, tab 24, schedule Staff 89, and that's appendices A and B, pages 5 and 6 of 6.

Hydro One's consequence and probability definition tables are included at appendix A and B of your response to Staff interrogatory 89.

And you say on page 3 of your response, which is just for your reference, at page 33 of the compendium, that planners use asset system and investment specific information to inform their investment risk assessment.

Have you benchmarked your risk categorization against the categories used by other utilities, or as might be contained in any other industry standards?

MR. JESUS: So as part of the Copperleaf system, we are part of the users group that uses Copperleaf and Copperleaf is being used extensively in the utility industry. So we are staying abreast of the developments on that front from a risk assessment point of view, and our risk assessment tools are very much in line with what other utility are doing. And in terms of the assessment tables A and B that you've shown, they are very much consistent with what other utilities are doing.

MR. SIDLOFSKY: Okay. And if we could go to your response to Staff interrogatory 100, and we've reproduced it at page 127 of the compendium -- just to be a bit more

specific, that's Exhibit I, tab 24, schedule Staff 100.

In that response, you provided a risk table summarizing the baseline and residual risk evaluation for system renewal investments over the planning period.

And at page 130 of the compendium, the reliability risk for SR-09 pole replacement moved from medium/major to unlikely/moderate as a result of the proposed investment.

And from appendix A of your response to Staff interrogatory 89, and again that's back at page 35 of the compendium, the reliability risk metric is tied to quantitative SAIDI values and number of outages.

So my question is whether the planner inputting assumptions into the AIP tool uses the same assumptions that were used for plan B modified, and that is the assumptions that were included in the -- tables 52 and 53 for SAIDI and SAIFI under the failure rate impact column.

MR. JESUS: I would suggest that the assumptions that were made into -- or the assessments that were carried out for pole replacement were the same for both plan B and plan B modified in terms of how we arrived at those risk assessments, depending on the number of poles we were doing and the contributions that would be exhibited -- where that would be identified for the reliability risk.

MR. SIDLOFSKY: Sorry, in table 52 at page 4 of the compendium, that's the SAIDI table, the assumption for poles under failure rates -- sorry, I'll give you a minute to get there.

The assumption for poles under the failure rate impact

column is that there are 345 outages a year, 180 customers per outage and 10 hours per outage. And that corresponds to 621,000 of interruption per year, correct?

MR. JESUS: Yes. Can we go to EB Energy Probe 17 for the latest and greatest numbers?

MR. SIDLOFSKY: Sure.

MR. JESUS: So in terms of the numbers that are shown there from an overarching SAIDI and SAIFI point of view, from a pole point of view, there is the contribution -- six of our overarching SAIDI are due to pole failures, and the number of outages that we experience each year are shown there.

From a risk assessment perspective, if we can go back to tables A and B of the risk assessment, which is Staff 89 -- so if we can go to attachment A, and focusing in on the reliability, if we can expand that reliability column to understand what the planners are actually entering and assessing from an overarching reliability risk.

As I provided in my -- in one of my -- in the transcript discussing how we go through the assessment for reliability risk associated with wood poles, they would look at the number of poles that have to be done, the probability of them failing, the -- so looking at the poor-condition poles, what's the probability of them failing, times the number of customers that would be interrupted, and then they would select from that list either one of those rows, so it's based on customer of interruption hours interrupted, as well as the other column right beside it,

is the frequency of distribution outages, so not only the hours, but the frequency, and they would relate it -- they would relate it to those two columns, and that would be the premise of their assessment. So --

MR. SIDLOFSKY: So just looking at Appendix A, 621,000 hours of interruptions per year, would those -- would that fall into the minor 4 category and -- for risk and not a major risk?

MR. JESUS: Which row? Sorry?

MR. SIDLOFSKY: If you have 621,000 hours of interruptions per year, I'm just trying to understand what category of risk that falls into. Is it minor 4 or major --

MR. JESUS: If you scroll to the left, for 600 -- keep going. For 600,000 it would be a minor 4.

MR. SIDLOFSKY: Okay. And similarly for SAIFI -- I'm looking at table -- okay. Sorry, I'll -- I won't get into SAIFI. That's okay.

Can you bear with me for just a moment?

So had you previously categorized the hours related to poles as a major risk?

MR. JESUS: I'm sorry, hours is one of the elements that we would consider as per the column under reliability risk, so hours of interruption is one of the items that we look at, as is the number of interruptions.

MR. SIDLOFSKY: So I guess my simpler question is how do you get from minor 4 to major, as a risk related to poles?

MR. JESUS: In your -- in that table of Staff 100, can you go back to the reliability-risk row. So just so again when we're -- we need to understand the baseline risk, and the baseline risk is associated with not doing any of the poles. So planners would evaluate, if I don't do any of the poles, what's the risk that I'm mitigating? And then if I do 70,000 poles, what's the risk that I'm mitigating, what's the remaining risk? So it compares the baseline risk with the residual risk.

For SR -- what is it? SR-06 that we're looking at? Sorry, SR-09. Can we look up the column where you have SR-09 in your compendium? Page 4 of Staff 100.

Okay. So in the -- what you see there in column 18 for poles, for reliability risk, was -- medium/major was the baseline assessment. And then the residual risk, once we carry out the program, we go to unlikely/moderate. Was that the question you were asking? How do we get there? So how do we get there? The planners would have to assess all the customers that are being impacted by those poles and the customer minutes of interruption and the customer -- and the number of customer interruptions that would be impacted by not doing those poles.

MR. SIDLOFSKY: So then hours are only one input into that determination, right?

MR. JESUS: From a reliability risk it would be the failure of those poles and the impact to the customers. Then they need to carry out that same process for each one of those other risk factors, and you can see there customer

risk, safety risk, shareholder value risk, the assessment process is the same, but carried out for each one of those factors.

MR. SIDLOFSKY: Thank you. Those are the areas that I have specifically for this panel, but I do have some follow-up questions that had been sent to you by previous panels.

First of all, could I take you to page 141 of the compendium. Now, that table was prepared by Board Staff, and it compares the productivity savings in the application as originally filed and in the update as filed in the interrogatory. This is a follow-up from panel 1, which goes back a couple of weeks now.

So those numbers were taken from Hydro One's response to Board Staff interrogatory 123, and we've included a copy of your response to Staff interrogatory 123 at pages 138 to 140 of the compendium. That's from Exhibit I, tab 25, Schedule Staff 123.

Now, on December 1st of last year Hydro One filed an update to the application which was designated as Exhibit Q, and among other items, Exhibit Q described a strategic change to Hydro One's vegetation management program, and that was included as attachment 2.

The executive summary of that report is on page 142 of the compendium. And that's from Exhibit Q, tab 1, Schedule 1, attachment 2, page 2.

And there you noted that Hydro One's current maintenance cycle exceeds eight years, but the three-year

cycle strategy proposed in this report will generate similar investment outcomes in one-third the time; correct? It is the highlighted line at the bottom of page 142?

MR. BOWNESS: Yes, I see that line, yes.

MR. SIDLOFSKY: Why would the new approach to vegetation management that you outlined in the September update not show up as a productivity initiative in this table -- I'm sorry, in the table that Staff prepared at page 141?

MR. BOWNESS: So if you look at --

MR. SIDLOFSKY: Sorry, that wasn't the table that Staff -- in the table that Staff prepared. It was in your response to Staff 123.

MR. BOWNESS: So there's two cost savings benefits that we see out of our OCP program, as we referred to in SEC.4, tab 4. We don't need to necessarily bring it up right now, but we had a belief that over the planning period, we would see ramping up towards 6 to 12 million dollars in trouble call savings.

And if we scroll up to your compendium on page 139, if we zoom in on the forestry initiative which is about halfway down, you will see -- embedded in the text of forestry initiatives, you will see the words "And overall unit volume reduction in trouble calls", so that's where we're accounting for the savings for the reduced number of tree-related outages.

The other piece is if we look at the optimal cycle protocol materials in SEC 4, tab 4, you will see that in

2023, this is when we are anticipating to be able to reduce the cost of the overall work program by $20 million, which is outside the horizon of this table.

MR. SIDLOFSKY: Okay. I have a few questions about capital price inflation that you've assumed for the derivation of your capital expenditures and of the capital additions that are added to existing assets each year, the drive to rate base and the capital revenue requirement each year of the custom IR plan.

We put this material to panel 1 on day 2 of the hearing, and that discussion is at pages 65 to 73 of volume 2 of the transcript and it can be -- we've included that at pages 143 to 151 of our compendium.

Just by way of a short preamble, at page 152 of the compendium, which is a copy of Exhibit A, tab 3, schedule 1, page 23, if we look at section 5.1.1, budgeting assumptions, we see that Hydro One set out its assumptions about OM&A and capital price inflation for 2018. Do you see that, panel?

MR. BOWNESS: Yes.

MR. SIDLOFSKY: Now, Staff's focus at the time was trying to understand what the capital price inflation is that's been factored into the 2019 to '22 capital expenditures and your capital additions, which are the key component for the increase in the rate base.

We explored it with panel 1, and they concurred that it was the increase in capital related revenue requirement that was dominating the increase in the overall revenue

requirement. It wasn't the OM&A that was the big driver, as that was assumed to grow at inflation less productivity, and that was 1.45 percent through June 2017 evidence, and then 0.75 percent with your Exhibit Q update.

Do you agree with that?

MR. BOWNESS: Yes. So the impacts on our rates are driven primarily based on capital additions as well as the load impacts, and OM&A is not a substantial factor.

MR. SIDLOFSKY: Okay. Panel 1 agreed that it was the increase in the capital related revenue requirement that was the dominant factor. And just for your reference, panel, we can see that at page 150 of the compendium.

I believe Mr. D'Andrea was agreeing with -- agreeing that OM&A contributed less than capital on a year to year basis, correct?

MR. BOWNESS: Yes, I see that.

MR. SIDLOFSKY: Okay. So what we're trying to focus on here is the capital inflation that you've assumed for 2019 to '22 in deriving your forecast capital expenditures and capital additions.

We have the overall capital expenditures, but it's not entirely clear to Staff what the inflation in capital prices is that you've assumed here, and panel 1 referred us to you.

So looking at the DSP, and specifically at table 31 of Exhibit B, tab 1, schedule 1, DSP section 2.1, and at page 153 of the compendium, we see factors for cost escalation for construction and cost escalation for operations and

maintenance by year, and that's based on your June 2016 forecast from IHS Global Insight, correct?

MR. BOWNESS: Correct.

MR. SIDLOFSKY: But what we can't see is if these are what are used in the forecasted capital expenditures. So can you explain, at an overall level, what capital price inflation you assumed each year in your forecasted capital expenditures and capital additions?

[Witness panel confers]

MR. BOWNESS: So there are two factors that we use. One is with respect to projects that we're estimating within the near term, and that's where we would have used -- for projects that would be submitted to this plan in 2016 that were under-estimates, they would have used the 1.8 percent, as an example from this table, for 2017.

If you look at program investments going forward, we used the CPI inflation number of 2 percent. And maybe I could take you to an example of that with pole replacement.

So if we look at SEC 29, which is issue -- Exhibit I, tab 18, SEC 29, on the second page of this, if you look at the unit costs on the pole replacements out in future years, you will see that we're appreciating -- if I take an example year, 2019, we're at $8,908 and a 2 percent appreciation is to go to 9,080; a 2 percent appreciation is 9,256; a 2 percent appreciation is 9,437.l. And that methodology would apply to program investments, as well as investments that have not gone through a detailed estimate, projects that have not gone through a detailed estimate.

MR. SIDLOFSKY: So you're using 2 percent where the IHS Global forecast is higher than that?

MR. BOWNESS: That's correct. We're using the lower number.

MR. SIDLOFSKY: The IHS Global forecast was from June of 2016. Has that been -- have you commissioned any update to that?

MR. BOWNESS: I'm not aware. I think that would be a question for our finance panel that was up already. There may be an opportunity with the last panel, I believe, to maybe ask that question of our load forecasting group that would have some insight into some of the financial elements.

MR. SIDLOFSKY: Well, I don't have your finance panel anymore, but is there any way that you could undertake to make those inquiries and provide me with an update, if you've obtained one?

MR. BOWNESS: We'll make sure that the panel that's coming up after the shared services panel will have that information.

MR. SIDLOFSKY: Okay. Next is from panel 2. And I'll take you to page 158 of the Staff compendium.

In Exhibit I, tab 21, Staff 73, or at least in your response to that interrogatory -- sorry, first of all, in the interrogatory itself, Staff noted that:

> "Hydro One described its labour optimization program as being planned to optimize the number of high-skilled regular work staff to the level

required to complete core work programs."

And in part C and D of that interrogatory Staff asked:

"To what extent labour optimization would be expected to impact recovery times from a potential major weather event with significant forestry effort requirements and the steps Hydro One is taking to manage impacts to recovery times."

And you made a couple of assertions in response:

"First, there would be no negative impacts on recovery times, because you remain mindful of them, and committed to improving current response times and reliability statistics. Second, to ensure there are no negative impacts, Hydro One was looking for operational enhancements in crew alignment and resourcing structure, in technology and grid modernization, and Hydro One also stated that prior to operationalizing these enhancements it is completing detailed assessments, including pilots, with localized implementation to ensure positive results and that once proven Hydro One would look to implement them throughout its business and achieve positive results."

Correct?

MR. BOWNESS: Yes, that's correct.

MR. SIDLOFSKY: How do you know that there won't be any negative impacts on recovery times when you are still completing assessments of the operational enhancements that

are intended to ensure that?

MR. BOWNESS: So if I take you through an example of distribution modernization, distribution modernization has the goal of being cost-effective to be able to respond to customer needs with improved reliability at a financially optimal cost, so if we're able to deploy sensors within the grid to be able to pinpoint where a fault is occurring, that's a technology enablement that is going to allow us to deploy our trucks in a more efficient manner to get to the incident faster and will have a benefit on reliability, so the pilots that we are looking at are with respect to improving the outcome at a lower cost.

MR. QUESNELLE: Mr. Sidlofsky, I hadn't anticipated that you'd have this many questions. Time estimate, just...

MR. SIDLOFSKY: I apologize, sir, it could be -- depending on the answers, it could be 15 minutes.

MR. QUESNELLE: I think the Panel has some questions as well. So we'd take a -- we've been -- had this panel up for the last session for two hours. We should probably take our lunch. I was hoping to release you before lunch, but we'll see you afterwards. And so let's come back at ten after 2:00.

MR. NETTLETON: Mr. Chairman, I do have some reading material for you.

MR. QUESNELLE: Okay. Well, perhaps we can pass that on to Staff and they'll get it to us.

MR. NETTLETON: Yeah, this is the material that's to

be treated as confidential.

MR. QUESNELLE: I understand.

MR. NETTLETON: And if I could -- I've made three sets, and I would prefer to give them to each of the Panel members if that's --

MR. QUESNELLE: Certainly.

MR. NETTLETON: Thank you.

MR. QUESNELLE: Okay. Thank you.

MR. NETTLETON: I wish I was heading out the door. Just a word of explanation. The materials have been copied in black and white. The...

You will recall that the filed version and the originals are all in colour. We didn't have the ability, and that may cause the need to refer to the electronic version that was filed and you will have to unfortunately go through.

We haven't been able to red-mark where the red redactions have been made, but that, I think, is the only way we can show you where the material has been unredacted.

MR. QUESNELLE: Okay.

DR. ELSAYED: Just a clarification. The redactions in the copy you just gave us are the black ones? I see some are still there.

MR. NETTLETON: Yes, the black redactions have been kept. The red redactions have been removed.

DR. ELSAYED: Okay.

MR. NETTLETON: Yeah.

MR. QUESNELLE: Okay. Thank you.

--- Luncheon recess at 1:11 p.m.

--- On resuming at 2:15 p.m.

MR. QUESNELLE: Mr. Sidlofsky, if you could continue when you're ready.

MR. SIDLOFSKY: Thank you, sir. Could we go to page 160 of the compendium, please?

For the witness panel's benefit, I'm continuing to follow-up with questions from panel 2 -- sorry, that was page 160 of the Staff compendium.

MR. NETTLETON: Apparently the electronic version is blank.

MR. SIDLOFSKY: The witnesses have copies of the compendium, do they not?

MS. GARZOUZI: Yes, we do, and we have page 160. Thank you.

MR. SIDLOFSKY: At page 160, we have a copy of the response to Staff Interrogatory No. 204, and that's Exhibit I, tab 40, schedule Staff 204.

In that interrogatory, Staff asked Hydro One whether it considered its 2017 ratio of casual employees of around 33 percent to be optimal. And your response was that you considered the ratio to be an effective use of resources.

I'm just trying to get some clarity on that response. Does that mean that in your view, the ratio is optimal?

MR. BOWNESS: At this point in time, we find it's the right balance between regular staff and hiring hall staff.

The reason I won't use the word "optimal" is we have a high number of apprentices that are working through our

system with respect to a demographic issue that we have at this point in our journey. So we have a higher level of apprentices than we've had historically, which is adding to an increased percentage of hiring hall staff because apprentices are deemed hiring hall.

So one thing that we do see as we get through this demographic bubble is that we're anticipating that we will have a smaller number of apprentices working through the pool -- still a good flow of apprentices, but the ratios will change slightly in future years.

MR. SIDLOFSKY: Okay. Moving to page 161 of the compendium, that I see is back on the screen now, that is a copy of your response to Staff interrogatory 105, Exhibit I, tab 40, schedule Staff 205.

In that interrogatory, Staff had asked whether hundred had conducted a staffing study to compare its staffing levels to other distributors and to determine the optimal staffing level for its operations.

And your response was that you hadn't conducted such a study as the regular and total FTE has been declining over the 2017 to '22 period and, as such, it hasn't been a priority for Hydro One to conduct a broad and likely expensive staffing study.

That's accurate, right, based on your response?

MR. NETTLETON: Sorry, Mr. Sidlofsky, this interrogatory was directed to Mr. McDonnell, so I just want to make it clear that you're asking about evidence that has been adopted by Mr. McDonnell, not by this panel.

MR. SIDLOFSKY: Did I read the answer accurately?

MR. BOWNESS: Yes, that's what the interrogatory response states.

MR. SIDLOFSKY: So my question is -- or one of my questions is why does the fact that fact that your FTE has been declining suggest that a study isn't necessary?

MR. NETTLETON: Well, again, Mr. Sidlofsky, I'm not sure that this panel can answer a matter that relates to labour. That was the area that Mr. McDonnell was testifying to, and this piece of evidence was in the chart that was directed to him.

MR. SIDLOFSKY: Well, sir, this was passed on to this panel by that previous panel. That's why I'm asking.

MR. BOWNESS: What I can speak to is I can speak to the way we approach staffing as compared to some of the other players in the LDC industry. We do take an approach on working very much in a partnership within our selective agreement rules with our Unions, and we're committed to using regular labour for our ongoing work.

If we want to move away from that, we have to be able to demonstrate that there's safety, quality, and cost effectiveness gains that would justify moving away from that strategy.

We feel we have a very strong balance between the use of our full-time regular staff and the flexibility that we have with the hiring hall resources. A number of other entities within the Ontario marketplace have different collective agreements and different strategies and rules

and agreements in place with respect to contracting out, but I can't speak to the specific question around the drive for the staffing strategy.

I think that was directed to Mr. McDonnell and I do believe that he did answer that question within a previous panel.

MR. SIDLOFSKY: And finally, on that point -- let me know if you can answer it or not -- if Hydro One staffing levels had been flat or increasing, would it have considered such a study useful, or would Hydro One's view be that a study wouldn't be useful under any circumstances?

MR. BOWNESS: I think, from a macro perspective, if our company wasn't achieving our overall objectives, we would look to leverage external sources and information to help us achieve an optimal outcome. We believe that as a part of this filing, we've leveraged the benchmarking reports that were asked of us. We've submitted that information. We've brought forward some of the materials that we've used to help shape our productivity gains and objectives. And I think that we have the right materials in order to support the application that's in front of this Board.

MR. SIDLOFSKY: Could I take you to page 162, please? And that's your response to OEB Staff Interrogatory No. 206, so that would be Exhibit I, tab 40, schedule Staff 206.

Staff noted that at Exhibit C1, tab 2, schedule 1, page 11-13 of the evidence -- and we've included that at

pages 163 to 165 of the compendium -- Hydro One summarized the efforts underway to manage its total FTE complement and increase efficiencies.

And Staff had asked Hydro One to provide the estimated savings for each initiative for the 2018 test year and future years under the various categories that were shown.

Your response was that the referenced evidence described the strategies and process changes Hydro One is employing to gain efficiencies in order to execute an increasing work plan with relatively stable FTE complement, and that the strategies described in each of the work programs have not been quantified as savings by Hydro One.

So my question is whether Hydro One undertook any cost benefit analyses when developing each of those initiatives.

MR. BOWNESS: By each initiative, are you referring to items such as our move to mobile project?

MR. SIDLOFSKY: That's right, actually in page 162 of the -- sorry, if we can just scroll up a bit there.

MR. BOWNESS: Yes, so I see your referencing move to mobile ...

MR. SIDLOFSKY: Among others, yes.

MR. BOWNESS: We did a cost benefit analysis. That is the business case that formulate the shavings that we put forward with our move to mobile project. We spoke to this with some questions the other day, I believe by Mr. Brett, and we talked about the clerical savings with respect to head count reductions and we spoke to efficiencies in the field with respect to a 5 percent goal on reducing unit

costs.

So yes, the background analysis for an initiative such as the move to mobile project was a cost benefit analysis on the business case to implement that solution.

MR. SIDLOFSKY: So aside from move to mobile, thinking in terms of engineering lines, forestry, and system maintenance, and those are described in detail at pages 163 to 165 of the compendium. Were there cost/benefit analyses related to those?

MR. BOWNESS: So these are example initiatives on what we've done within our overall work program, and I think within this exhibit we speak to the summary of this being Exhibit I25, Staff 123, and if we could bring that up I can show you that within each one of these, this is the net productivity gain that we have out of these initiatives, so if we could just bring that up to on the screen you'll see that we have approximately $70 million run-rate savings in 2018.

Could we bring up the exhibit, please? Staff 123, Exhibit I, tab 25, Staff 123. Just scroll down to the table on the second page.

These are the committed to productivity savings that we updated in the evidence as of the end of 2017, with the committed savings by initiative over the period of the submitted evidence and submitted application.

So it's not an exact one-for-one, because things changed, right? If you look within the question -- there was a question around how did we handle the Muskoka

project. Well, the Muskoka project in forestry was a point-in-time initiative on clearing a number of the feeders in the Muskoka area to drive-improve reliability. And then this is subsequently transitioned into our optimal cycle protocol initiative, so the approach on taking a focused approach on driving reliability on some targeted feeders was part of the input into our evolution in our vegetation management strategy. Ultimately that culminates in the savings that we have in this table under forestry with respect to reduced trouble calls and then our future targeted savings of $20 million in annual work program.

MR. SIDLOFSKY: Okay. Thank you. You will be happy to know I'm down to my last two questions, and they relate to OM&A. I'm going to take you to pages -- sorry, pages 171 to 177 of the compendium. Those pages include your responses to Exhibit I, tab 38, Staff 189 to 192 and Staff 194.

And in those interrogatories Staff asked you for information for the years 2012 to 2017 for the number of trouble calls, that's at Staff 189, the number of disconnect and reconnect calls per year, that's at Staff 190, the number of defect corrections per year, that's Staff 191, the number of PCB inspections and testing per year, that's Staff 192, and the number of kilometres of line cleared and line brush control in Staff 194. And Staff also asked in those interrogatories for you to comment on that information.

Now, in Undertaking JT3.17, from the technical

conference -- and that's at page 178 of the compendium -- Hydro One was asked to provide the costs of each of these activities for the same time period. My question is whether Hydro One can comment on whether or not meaningful information on efficiency improvement trends would result from taking the costs of each of these activities as provided in the undertaking and dividing them by the volumetric information contained in the respective interrogatories.

[Witness panel confers]

MS. BRADLEY: In some programs that unit cost calculation is meaningful; in others it's not. It depends on how repeatable the scope is and the size of each project under that program. As we stated at the beginning of this process, we are committed to looking at every program to find efficiencies, and we can see that through this application and the efficiencies that we've added since the time it was filed.

So that would be one of the parameters that we would look at, but it's very dependent on the variation within different investments or different units that are done in these -- in some programs.

MR. SIDLOFSKY: Well, of these categories on page 178, can you tell me which ones would be instructive and which ones wouldn't in terms of efficiency trends?

MS. GARZOUZI: I'll take you to the items, so for trouble calls there is significant volatility in the impacts of events on our system, and so I think that that's

a difficult one to look at from an efficiency perspective.

For disconnect, reconnect, that one really depends on the travel time that it would take to get to that premise and to conduct the reconnect, disconnect, but that could be a way of looking at it.

Defect correction, there's a lot of defects bundled into defect correction, so it depends on the defect correction type.

For PCB we are really looking at touching that transformer once, so minimizing the times that we have to either do a test or a replacement on that asset, so where possible we've really focused at 2017 at grouping work, at avoiding the test on a 1920 transformer, for example, and simply replacing it if the wood pole is at end of life and it's failed a condition test, so where possible, really grouping the work to help improve the unit price.

And for brush control and line-clearing, that really is a transformation that you see in the optimal cycle protocol, so I would say, yes, we've really shifted the approach there, looking at focusing high risk, high criticality defects, trading that off for low criticality defects.

MR. BOWNESS: On that last one, we do as use a lot of unit cost metrics, cost per defect, cost per kilometre, for our new OCP program, to make sure we're turning towards the goals and objectives that we have to get to our three-year cycle.

So it is the one there that we are looking at on a

monthly basis from a unit costing perspective.

MR. SIDLOFSKY: Okay. Thank you, panel, those are my questions, and thank you, Mr. Quesnelle. I realize I'm over my scheduled time. I appreciate the Board's indulgence.

MR. QUESNELLE: Okay. Thank you, Mr. Sidlofsky.

Ms. Anderson, do you have any questions?

MS. ANDERSON: I do. You thought you were done.

**QUESTIONS BY THE BOARD:**

MS. ANDERSON: So you have told us about certain assets that you do run to failure strategy, and examples, I think, were pole-top transformers, conductors, insulators, that kind of thing; that's correct? So for those, my understanding is you record defects, and then once you've identified those defects you do a trouble call; is that correct?

MS. GARZOUZI: No, so -- well, it would depend, so if something required urgent attention, then there would be what we would call post trouble, so it would be a line item there, but there's a program called "defect correction", and so it is usually done under that program.

MR. BOWNESS: And I think Ms. Bradley spoke to an example there where you would have potentially during trouble and storm response a number of splices that you would make on a particular span, and then when there is a certain of number of them we could come back and we would replace that to have fewer splices on that span.

MS. ANDERSON: So my question is really for the defect

correction projects. Do you have a backlog?

MS. GARZOUZI: Yes do.

MS. ANDERSON: And I guess it's different for each asset, but is it -- I mean, given that we've looked so much at those that are on the planned replacement and what that looks like, so what sort of backlog might there be for these sorts of assets?

MS. GARZOUZI: We're actively managing the backlog of defects that we have. We're actually monitoring them on a monthly basis and we're really trying to reduce those without triggering a truck role specifically for that so, where possible, grouping it with other work. So we're seeing that number decline.

The high priority defects, we're at about 30,000 right now, which is a reduction from what we had. And so we're seeing the trend being reduced, and I think move to mobile is really helping us manage that and reduce that.

MS. ANDERSON: Okay, thank you. One word that I haven't heard in your investment planning or asset planning process is cash-flow.

I heard that you have constraints and one of those is obviously impact on customers, and you've taken that into account.

But what about the cash-flow of the organization? Is that ever a constraint, or do you just assume that whatever investment you come up with, you can just -- it's just going to be -- I guess you can borrow the money in order to do the investment.

MR. BOWNESS: Yes, so from a work plan perspective, we look at two dimensions of expenditure. We look at the capital expenditure as to how much money we're spending and then we also look at the in-service edition, i.e. when the asset work is complete and it is on the grid being used and useful.

Within the distribution business, it's much more one-to-one. In the transmission business, there is a longer lag. But what we do within the broader company is our treasury group within finance looks at the work plans that are approved or being submitted to being approved, and they develop an approach with respect to how do you use existing funds from operation. How do you use debt issuance into the marketplace in order to make sure that the cash-flow that's required to support the work program is met.

But the specifics of how the treasury function would work, I defer that to our finance team.

MS. ANDERSON: I guess I was kind of wondering and -- sorry, your holding company is Hydro One Ltd., is that correct, for the corporate functions?

MR. BOWNESS: So there is Hydro One Ltd., which is the parent can company, the new parent company since going public. Hydro One Inc. is the one that manages the regulated business. And then you have Hydro One Networks, which we are part of, which is the majority of the T&D assets.

MS. ANDERSON: I was just wondering if any of the parent companies ever put cash-flow restraints on some of

the investment decisions.

MR. BOWNESS: Not that I'm aware of. Typically, we're going out into the market in order to be able to support the work programs.

At no point during my experience has it been we have to slow the work program down because of dash cash-flow issues. So I defer to the treasury team to speak to the mechanics of how they go to market about how they to borrow money, but it hasn't been a concern that's come down to me at any point in the last number of years from a delivery perspective.

MS. ANDERSON: And I think that was where my question was, did it provide any limitations to you in doing your asset planning.

MR. BOWNESS: No.

MS. ANDERSON: Okay, last question, just so I'm clear. ISDs; so is every project that's over a million dollars given an ISD number, is that correct? I saw somewhere in the evidence about a million. I just wasn't sure that means every project.

MS. GARZOUZI: Every project or program above a million would be in an ISD. And sometimes in the ISD, there is a grouping of multiple.

MS. ANDERSON: Right, so some programs are multiple projects, but -- and I won't say the pole replacement program. That would be one that would have an ISD, but every project over one million --

MR. KARUNAKARAN: One million.

MS. ANDERSON: -- would have an ISD. And I just want to confirm that, and you have another category of major projects and that's 5 million. And there is only Leamington over the whole course of the whole five years, is that correct, as far as a major project, and it was 5 million -- more than.

MS. GARZOUZI: I think that was based on a conversation that we had when Mr. Bowness was describing what was in flight, and that was based on the work program that he's managing at the moment. But in the filing, there are some that are greater than.

MS. ANDERSON: That's what I was asking.

MS. GARZOUZI: And there's a few.

MS. ANDERSON: Currently, you have only one, but there are others within the five years?

MS. GARZOUZI: That's correct.

MS. ANDERSON: That was my question. Thank you.

MR. QUESNELLE: Dr. Elsayed?

DR. ELSAYED: I only have one question of a general nature. You've told us in the last few days about some of the initiatives that I've undertaken to improve your -- both your planning process and the execution of your capital and OM&A programs.

So my question is in two parts. Can you provide us with kind of a high-level summary of what is in your evidence in this application that demonstrates the results of those improvement initiatives that you are undertaking, specifically comparing what you have in this application to

what you had in the previous rate application?

What have you shown as improvements as a result of the initiatives that you've explained in the number -- in the last few days?

Sorry, let me tell you the second part as well, so you can think about it. This is going forward, same question. What measures would you be monitoring or tracking over the next number of years, again to demonstrate improvements that you would be realizing from this application to the next rate application?

[Witness panel confers]

MS. BRADLEY: The two areas that there's materials in the application include $400 million of productivity. That was a significant increase in the productivity included in this plan compared to past plans, and that's included in Staff I-123 and that demonstrates the improvement we've made from the time we filed until the time that we got here.

The other area where there is a significant amount of improvement from the past plan is in reliability. And in reliability, we do show a number of initiatives that we are taking to improve reliability without changing the funding requirement that was originally submitted in this plan.

And there's a detailed view of those reliability improvements that were submitted in J1.11, that shows, you know, our past trend and the improvements that we intend to achieve and the areas in which we plan to achieve those.

DR. ELSAYED: Thank you, I was thinking more of, again

focusing on your areas of expertise, planning and execution. In planning, what my question is: You develop a plan, a DSP, and you execute according to plan. So my question is: How would you -- what would you tell me now in terms of how what you are proposing in this application corresponds to the plan that you submitted in the last application.

And you also had a program to execute both capital and OM&A. How would you describe, in general terms, how successful you were in executing the plan that you had in the previous application? And the same question applies going forward, specifically on those two areas, planning and execution.

[Witness panel confers]

MS. BRADLEY: In developing the investment plan there was a significant amount of customer consultation and an iterative process that was used with our board to determine the right balance between the customer needs and preferences, the assets, and the rates.

There's a standalone DSP that we have submitted as part of this application, which was part of the planning process. There's a number of planning aspects through the governance document you saw in productivity that sort of bridges planning and execution to develop the reliability improvements that we've incorporated, and there's a number of changes in the planning process that were sort of foundational in developing some of the reliability improvements.

I know Ms. Garzouzi walked through the planning process for worst-performing feeders, for example, where we've developed a methodology and a way to assess and evaluate those types of investments, which we didn't have in the past, and the incorporation of grid modernization, where we learned from the pilot project that we did at Owen Sound and intend to incorporate the learnings from that through our grid modernization going forward in this plan.

I'll let Mr. Bowness speak to the work execution fees.

MR. BOWNESS: Yeah, so I think I will speak to things a little bit more macro-ly, as I've seen the company significantly transform since we went public in 2015.

There is an extreme heightened focus on outcomes and accountabilities. And if I look at how we're measuring our overall leadership team and management team from an outcomes perspective, there has been a significant improvement in our corporate performance management process and overall metrics.

We review our team scorecard on a monthly basis. And everybody within the leadership team and as it cascades down through all managers in the company, we are all measured against that team scorecard, so whether it's customer service, whether it's health and safety, whether it's work program efficiency, productivity, all of these metrics that we've had that you see within our team scorecard, we are all held accountable to that, and we either win together or we lose together. And what I think is transformed is that we are all rallying towards the

overall corporate goals and the outcomes that we are trying to achieve.

The other thing that I would say is you go a layer deeper and you look at the improved use of KPIs and scorecards and measures that are being asked upon by us by the regulator as well as with industry benchmarks is we're getting a lot smarter around where we fit, where we stack up, how are we performing on industry benchmarks as compared to other distributors and other entities within the North American utility space. And I think we're using that information to challenge ourselves to get better. And we're reporting on those results on an annual basis into the regulatory process or the submissions that we have on the scorecards, as well as using that information internally.

If I go a layer deeper and I look at my team's accountability, I have monthly reports that we review with my overall team to look at our measures and our outcomes and our accomplishments to make sure we're meeting the asset needs and ultimately the reliability and customer satisfaction that we are expecting to get out of our work programs.

So I think there truly has been a transformation around metrics and reports and information to lead to really strong outcomes, and I think on a go-forward basis you will see what we've submitted in evidence with the targets that we have in our team scorecard, the targets that we've set in the OEB scorecard and supplemental

scorecard is that we are truly committing to an ever-improving business, and nowhere more so is that than on reliability.

We truly believe we need to deliver a better product, and we are setting very aggressive targets on reliability over this five-year period.

DR. ELSAYED: Thank you.

How often do you update your DSP?

MS. BRADLEY: We update the DSP as submitted here for the purposes of an application, but we do have an annual investment planning process where we update our five-year plan, and then we have the monthly redirection process where we adjust for monthly variances that we experience for events.

DR. ELSAYED: So when you update your investment plan, do you look at critically what you did versus what you planned and any lessons learned from that going forward --

MS. BRADLEY: Yes, we do. I think even the fact that, you know, we submitted this application in March and in December when we provided an update we had a number of significant changes that we made both with respect to productivity, reliability, the new vegetation management program as a result of that critical look that we take at our business and how we can improve.

You know, in hindsight would it have been easier to wait for a few months? Maybe. It would have made this process easier. But we are very committed to continuously looking at what we can do to improve what we've heard from

people, whether that's, you know, audits, whether that's through benchmarking, through industry forums we are a part of, so that critical look is there, not just on that annual investment planning process time line, but in the regular communications and dialogue that we have. We believe our part of the business, like my role, is to make our business better, not just to keep doing what we've done before.

MR. BOWNESS: And a much stronger tie-in between the planning group and the execution group. As we've seen, the improvement in our accuracy on in-service additions in 2015, we were off by over $100 million. That was unacceptable from our perspective, and that's why we put in a much more robust process in redirection, so that we are managing within our means, and knowing that, yes, that means that we are going to have to redirect away from some work programs at times, but we're going to manage within that capital envelope to achieve the best possible outcome.

DR. ELSAYED: Thank you. Those are all my questions.

MR. QUESNELLE: Okay. Thank you.

Mr. Nettleton, I don't have any questions myself. Do you have anything you want to follow up on?

**RE-EXAMINATION BY MR. NETTLETON:**

MR. NETTLETON: I do, Mr. Chairman, if you would just bear with me.

Mr. Bowness, just following up on your last response, you were speaking of managing to a capital envelope. Why is it appropriate to manage to a specific capital level, capital spend level?

MR. BOWNESS: I think there's two reasons from my perspective as to why it's appropriate to manage to a capital envelope.

The first one is the rates that we've asked for are encompassing based on a financial cost of doing work. And if we don't adhere to those costs, and we come into the subsequent rate hearing and we say we've spent X amount of dollars over that envelope, we're retroactively asking the OEB to approve that, and I think it puts the whole process in a difficult position with respect to approving or denying work that's already been completed, so I think managing within the envelope is important to make sure that we're staying true to what we asked for.

The other piece that I would put forward, and I was asked this question, I think, within the TX filing as well, if I'm recalling, is, you know, why wouldn't we set a target of 98 percent of our capital expenditure, or 96, and the reason I don't think that's appropriate is that we know when we've seen in the evidence that there's more investment and there's more asset needs than we can afford to spend, so if we set a target of 98 percent, my team would manage to 98 percent, and we'd be further away from what the assets need, so I think through our redirection process and our willingness to reinvest any cost savings on the capital side is yielding an ever-improving income for a defined capital envelope.

MR. NETTLETON: Panel, there has been much discussion about the SAIDI and SAIFI statistics. You were having a

discussion with Mr. Sidlofsky earlier today. And I just want to ask you a question in follow-up to that exchange.

Panel, are you familiar with the term "lagging indicator"?

MS. BRADLEY: Yes.

MR. NETTLETON: Could you explain what a lagging indicator is?

MS. BRADLEY: In the case with reliability we use condition of our assets as a leading indicator. As the condition worsens you are not going to have reliability impacts, you know, the day after something is in poor condition. Reliability impacts are a lagging indicator in that you see the impact of poor condition after that condition has deteriorated.

MR. NETTLETON: Are SAIDI and SAIFI lagging indicators, Ms. Bradley?

MS. BRADLEY: Yes, they are.

MR. NETTLETON: Do lagging indicators have predictive value?

[Witness panel confers]

MS. BRADLEY: I would say that there is some, but limited predictability. Once you see the impact in SAIDI and SAIFI, it's too late or significantly late to make a difference in a timely manner to that number.

MR. BOWNESS: I think a lagging indicator as well is if you are seeing a trend of deterioration and you don't do anything about it, there is a higher likelihood that things are going to continue on a bad path.

So it's a lagging indicator that is a call to action to do something about it.

MR. NETTLETON: Mr. Bowness, in your exchange with Dr. Elsayed just moments ago, I heard you indicate that there had been significant changes introduced in this application and what you were planning to move forward with.

What I didn't -- and what I'd asked you to all elaborate on is the past and the past transactions -- or sorry, the past application that has been made to this Board, and other application that is been made in to Board in your experience.

How long have you been with Hydro One, sir?

MR. BOWNESS: As an employee, I've been with Hydro One fifteen years.

MR. NETTLETON: And Ms. Bradley, how long for you?

MS. BRADLEY: Thirty years.

MR. NETTLETON: Panel, with respect -- Mr. Jesus, how long have you been with the firm?

MR. JESUS: Thirty-one years.

MR. NETTLETON: And Ms. Garzouzi?

MS. GARZOUZI: Fourteen years.

MR. NETTLETON: Thank you. Panel, can you elaborate on how productivity and efficiency have been considered, as well as customer needs and preference has been considered in prior applications, and compare that to this application?

MR. BOWNESS: So from my perspective, asking --

looking specifically around productivity, I would say that this is our strongest application that we've ever had with respect to our productivity goals going forward.

I think historically we've spoken to productivity. There's been productivity exhibits. But I don't think we've had the strength and the integrity of the proof and how it flows right to actual work units and work outcomes and ultimately, overall business outcomes.

So the strength in our productivity governance and tracking is stronger than I've ever seen it in the history of our company.

The other piece on productivity is our overarching objectives of trying to achieve annual run rates of, within distribution, 70, 80, $90 million and you will see similar numbers coming out of our transmission side of the business.

I think it's second to none. I think the push that we have from our leadership team, from our board of directors, from the regulator, from our customers around being more productive is really driving a transformational behaviour, and is far improved over anything I've seen in the 20 years that I've been in and around Hydro One.

The second piece is with respect to customer. Every single division within Hydro One is talking about customer. We talked about customer historically within the customer service team. Now we're all talking about customer: How does this benefit the customer? How do we interact with our customer?

I think there has been customer focus forever as Hydro One, ultimately we are in the business of providing safe, reliable, affordable power to customers. But the focus in on our customer and considering them in all of our planning activities, considering them more in our execution activities and the transformation that's occurring within the customer group as the customer panel spoke to is really far improved as well.

MR. NETTLETON: Sir, what do you attribute these changes to?

MR. RUBENSTEIN: Sorry, I don't want to object. But this, I believe, goes beyond re-direct.

MR. QUESNELLE: Anything specific that you want to point the witnesses to in the cross-examination by others?

MR. NETTLETON: There was simply a follow-up to Dr. Elsayed's question that I heard with respect to him asking a question about what the past was, what the current is, and what the future is going forward. And what I didn't hear the witnesses speak to was the past.

So that's why I was asking the witnesses about what the past was to give contrast to what the future was going forward. That's all, sir.

MR. QUESNELLE: That's fine, but I think that specifically could have been pointed to in your re-direct.

MR. NETTLETON: I think I did that, sir. I think I did.

MR. QUESNELLE: I hadn't picked up on it. Sorry.

MR. NETTLETON: So my final question is: What do you

attribute that difference to, sir?

MR. BOWNESS: I attribute it to a change in leadership. Really things have stemmed since we've gone public and the strength in our overall leadership team to drive to better outcomes.

MR. QUESNELLE: Thank you to the panel. I'm sure this has been a trying few days. Thank you very much for your forthright evidence.

Mr. Nettleton, why don't we take a ten-minute break to allow the panels to shift and we'll return. Thank you.

MR. NETTLETON: Thank you.

--- Recess taken at 3:01 p.m.

--- On resuming at 3:13 p.m.

**DECISION:**

MR. QUESNELLE: Just before you introduce your new panel, Mr. Nettleton, the Board was -- made its determination with respect to the Undertaking J7.1.

The Board has determined that it will not compel Hydro One to provide any further information either in the public record or on a confidential basis with respect to its filed response to Undertaking J7.1.

The OEB has reviewed the redacted elements of the undertaking that Hydro One referred to as being related to sensitive commercial information related to third-party contract negotiations or staffing matters and finds that they are of the nature that Hydro One has described.

The Board's initial ruling compelling Hydro One to undertake the production of the information was intended to

better inform how the work of the various work streams fed into a report to Hydro One's board of directors.

The Board observes -- the OEB observes that the working papers that have been provided which were used at the -- at a series of steering committee meetings in advance of the board of directors meeting are very general in nature.

The OEB finds that, while the nature of the discussions in the working papers may be relevant to the subject matter of the application, given the lack of any specific connections by way of specific recommendations, for instance, the OEB places little probative value on the information in terms of testing what Hydro One ultimately included in its application.

Given these findings, the OEB sees little merit in compelling any further disclosure. Thank you.

MR. NETTLETON: Thank you, sir.

MR. QUESNELLE: Thank you.

Okay, carry on with the introduction of your next panel.

MR. NETTLETON: Thank you. Panel 6 is the shared services panel, Mr. Chairman and Board members, and this panel has four witnesses that are attending today. Closest to you is Mr. Tom Irvine. Mr. Irvine is the director of system control at Hydro One. Seated beside Mr. Irvine is Mr. Rob Berardi. Mr. Berardi is the vice-president of shared services. Seated beside Mr. Berardi is Mr. Lincoln Frost-Hunt. He is the director of enterprise information

technology. And finally, seated beside Mr. Lincoln Frost-Hunt is Mr. Imran Merali, whom has testified previously in this proceeding. He is the director of custom program delivery.

Could the witnesses have the oath administered?

**HYDRO ONE NETWORKS INC. - PANEL 6, SHARED SERVICES**

**Tom Irvine,**

**Rob Berardi,**

**Lincoln Frost-Hunt,**

**Imran Merali; Affirmed.**

**EXAMINATION-IN-CHIEF BY MR. NETTLETON:**

MR. NETTLETON: Thank you, Ms. Anderson.

Gentlemen, there are two pieces of evidence that I will be referring to. The first is Exhibit K1.1, which are the curriculum vitae that were pre-filed as part of Exhibit A-9-2 in this proceeding, and also Exhibit K1.2, which is the draft hearing plan and the table that starts at page 46 of 58 of the PDF version of that document.

If you could have that information before you, what I'd like to do is ask a few questions, starting with you, Mr. Irvine, and identify the evidence that you intend to adopt as your evidence in this proceeding.

So if we turn to page 39 at the top -- oh, sorry. Yes. Mr. Irvine, can you confirm that the evidence listed on this page and I believe going over to the next is the evidence you intend to adopt in your proceeding?

MR. IRVINE: Yes, I do.

MR. NETTLETON: And do you have any changes or

corrections to make to that evidence, sir?

MR. IRVINE: I do not.

MR. NETTLETON: And is it therefore accurate to the best of your knowledge and belief?

MR. IRVINE: Yes.

MR. NETTLETON: And do you therefore adopt that evidence as your evidence in this proceeding?

MR. IRVINE: Yes.

MR. NETTLETON: Mr. Berardi, your name appears, I believe, first on page 39 of that document. And can you confirm the evidence listed there is the evidence you intend to adopt in this proceeding?

MR. BERARDI: Yes, I do.

MR. NETTLETON: And do you have any changes or corrections to make?

MR. BERARDI: Yes, I do. I have a correction to Exhibit D1, tab 1, Schedule 4, material and supplies inventory. There is an error in table 1, and I conferred with our finance friends. It has a minimum impact to revenue requirement, and I will just run you through the changes -- or the corrections.

For 2019 the total inventory number should be 35.6 million. For 2020 the total inventory number should be 36.3 million. For 2021 the total inventory should be 37.1 million. And for 20222 the total inventory number should be $37.8 million.

MR. NETTLETON: And, sir, those corrections are made to which table, table 1 or table 2?

MR. BERARDI: Table 1.

MR. NETTLETON: Thank you. And with those changes and corrections, Mr. Berardi, do you -- is the evidence accurate to the best of your knowledge and belief?

MR. BERARDI: Yes, it is.

MR. NETTLETON: Do you therefore adopt that evidence as your evidence in this proceeding?

MR. BERARDI: Yes, I do.

MR. NETTLETON: Thank you.

Mr. Lincoln -- Mr. Frost-Hunt, can you confirm that the evidence you intend to adopt in this proceeding is the evidence shown on pages 41 and 42 of Exhibit K1.2?

MR. FROST-HUNT: Yes.

MR. NETTLETON: And do you have any changes or corrections to make to any of that evidence?

MR. FROST-HUNT: I do not.

MR. NETTLETON: And is it therefore accurate to the best of your knowledge and belief?

MR. FROST-HUNT: Yes, it is.

MR. NETTLETON: And do you therefore adopt that evidence as your evidence in this proceeding?

MR. FROST-HUNT: Yes, I do.

MR. NETTLETON: Thank you.

And finally, Mr. Merali, your evidence is listed on pages 39 and 40 of Exhibit K1.1 -- sorry, K1.2; do you see that?

MR. MERALI: I do.

MR. NETTLETON: Do you have any changes or corrections

to any of that evidence?

MR. MERALI: I do not.

MR. NETTLETON: And is it therefore accurate to the best of your knowledge and belief?

MR. MERALI: Yes, it is.

MR. NETTLETON: Do you therefore adopt that evidence as your evidence in this proceeding?

MR. MERALI: I do.

MR. NETTLETON: Thank you.

Mr. Chairman, this panel does not have an opening statement, so it is now available for cross-examination.

MR. QUESNELLE: Great, thank you, Mr. Nettleton.

Mr. Ladanyi.

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

MR. LADANYI: Good afternoon, panel, my name is Tom Ladanyi. I am consultant to Energy Probe. A couple of days ago I sent out a list of exhibits that I would be referring to. Unfortunately I'd assumed that this panel would be dealing with affiliate transactions also, and I understand it is not, so some of those exhibits that I listed I will not be asking any questions about, so hopefully my time will be less than half an hour. We'll see how it goes, and I -- because we are considerably behind schedule right now, so hopefully we'll gain some time.

MR. QUESNELLE: I appreciate the effort, Mr. Ladanyi.

MR. LADANYI: Thank you. So if you could first turn to tab 25, Energy Probe 37, and in that interrogatory we

asked about sale of properties. And three properties are listed: Matheson area office, former Bracebridge area office, and former Nipigon MEU office.

And I'd like to know whether these were -- there was a profit on the sale of these properties?

MR. BERARDI: I don't know whether there was a profit. We did go to the open market to sell these properties. I do not have in front of me the sale, disposition, and whether there was a profit on these...

MR. LADANYI: I hate to ask for an undertaking this late in the process, but could you give me an undertaking to find out whether there was a gain on the sale of the properties?

MR. BERARDI: Yes, I can.

MR. LADANYI: And as another part of that undertaking also whether you were sharing or you did share in the past the profit on the sale with the ratepayers. Can I have an undertaking number?

MR. SIDLOFSKY: It will be J9.1.

**UNDERTAKING NO. J9.1: (A) TO ADVISE WHETHER THERE WAS A GAIN ON THE SALE OF THE PROPERTIES; (B) TO ADVISE WHETHER HONI WAS SHARING OR DID SHARE IN THE PAST THE PROFIT ON THE SALE WITH THE RATEPAYERS.**

MR. LADANYI: Thank you.

Can we next turn to tab 29, School Energy Coalition number 58. Do you have that in front of you?

MR. BERARDI: Yes, I do.

MR. LADANYI: That is, as I understand it, your

complete listing of the vehicles and helicopters as well that Hydro One owns.

Are these are owned, by the way -- let's start like this -- or are some of them leased?

MR. BERARDI: These are owned.

MR. LADANYI: These are owned. All right. And I was interested, actually surprised how many vehicles there are. Hydro One, as I understand it from evidence earlier in this case, has roughly 8,500 employees; would you accept that?

MR. BERARDI: Yes, that's correct.

MR. LADANYI: And some of those employees are in the office here in Toronto, and others are outside in field operations. So roughly, how many employees would be in field operations? Roughly only.

[Witness panel confers]

MR. BERARDI: Approximately 6,000, subject to check.

MR. LADANYI: 6,000. So there are actually more vehicles than employees, would that be right? So it's really -- so can you explain to me -- like how much use do these vehicles get, or this equipment? A lot of them must be just sitting around, I assume.

MR. BERARDI: I just wanted to address the utilization. So in 2017, we've implemented a tool called telematics. And during that time in 2017, we reduced our fleet by approximately 10 percent. So we went from 8,000 in 2017 to 7,200.

And so by implementing tools like telematics that gives us real-time information on utilization and real-time

information on idling, we were able to reduce our fleet by 10 percent.

So the numbers that you are seeing are as a result of the fleet reduction from 8,000 to approximately 7,200.

MR. LADANYI: Does each employee in the field have a vehicle?

MR. BERARDI: No, they do not.

MR. LADANYI: And these do have vehicles, are they allowed to take them home?

MR. BERARDI: It really depends. It really depends on the work that they're doing. So, for instance, if they're moving from one location to another location, it might be more efficient for them to take that vehicle home.

But for the most part, large, heavy equipment, would be at the operation centre, so they would have to drive to the operation centre to get some of the large classes.

MR. LADANYI: Some companies have a policy of returning all of the light vehicles and virtually all the vehicles back to the yard, the company yard, at the end of a shift. Do you have that similar policy?

MR. BERARDI: We do not.

MR. LADANYI: Do not. Have you considered something similar?

MR. BERARDI: Not to the best of my knowledge.

MR. LADANYI: Is there -- do employees get charged for personal use of the vehicles?

MR. BERARDI: They do.

MR. LADANYI: And it becomes a benefit, or how are

they charged?

MR. BERARDI: Well, I believe it's through the CRA rules and taxable benefits. I'm not the expert in this area.

MR. LADANYI: All right. Do you keep track of kilometres per vehicle per year?

MR. BERARDI: Yes, we do.

MR. LADANYI: And I presume that would vary. I guess heavy equipment would have lower kilometres than light vehicles, is that right?

MR. BERARDI: That's correct.

MR. LADANYI: I don't want to ask you an interrogatory -- or an undertaking for that, because I'm not sure if the numbers will be meaningful to me. But I'm assuming you are monitoring this and you are getting efficient use of vehicles, and that's your objective, is it?

MR. BERARDI: Yes, we do a regular asset condition assessment on each one of our vehicles, so we have very detailed accounts on each piece of equipment.

MR. LADANYI: One last question about the vehicles before we go to another subject. So at what point in time would you be disposing of vehicles?

MR. BERARDI: It really depends. It really depends on class. It really depends on usage, and it really depends on the amount of kilometres, wear and tear.

So for instance, light vehicles versus heavy have different criteria for when we dispose. But we do have a regular asset condition assessment that we do on an annual

basis on each one of those pieces of equipment.

MR. LADANYI: I have one sub question on vehicles as well. I was interested in how long your vehicles last, so I looked into the depreciation rate review and I didn't find an item there for vehicles. And you probably don't know this because you are not an expert in depreciation, but I'm not sure -- I don't actually understand why the vehicles, if you owned them, they would not be listed as one of the assets in the depreciation study. You don't know the answer to that, do you?

MR. BERARDI: I do not know the answer to that, no.

MR. LADANYI: Sorry to ask you, but would it be to be have an undertaking on that as well? An undertaking that you can ask somebody in the accounting department why the vehicles are not listed in the depreciation rate review.

It is Exhibit C1, tab 6, tab 1, schedule 1.

MR. BERARDI: Okay.

MR. LADANYI: I don't want to take you to it, because we have limited time. So let's go to the next item, which is integrated system operation centre, tab 29, School Energy Coalition 61.

MR. SIDLOFSKY: Sorry, Mr. Ladanyi, were you asking for an undertaking?

MR. LADANYI: Yes, I am. I am moving too quickly.

MR. SIDLOFSKY: That's okay, it's J9.2.

**UNDERTAKING NO. J9.2: TO EXPLAIN WHY VEHICLES ARE NOT LISTED IN THE DEPRECIATION RATE REVIEW AT EXHIBIT C1, TAB 6, TAB 1, SCHEDULE 1.**

MR. LADANYI: Thank you. So there is a fair amount of evidence in the case already on this item, on the integrated system operation centre. And that was originally called a back-up control centre and there was a scope change. And I understand all this; I read the evidence.

I have a more basic question here. This is justified on the basis of need, so if it's a basis of need, is this a matter of cost is no object here? Like for example, if the integrated system operation centre cost 76 million instead of 56 million, would that still be all right? What would be the upper limit that you would have allowed for this?

MR. IRVINE: So in regard to the system operating centre, you are correct in that it is a need for us. We operate one of the largest distribution and transmission systems in North America and we do it from a single control centre. As such, having a back up control centre is critical to our business.

As far as cost and needs, we are cognizant of the cost and looking at the needs and what it is that we require to do, we take that into consideration to ensure that we look at all those pieces and put in what is required as part of the cost structure.

MR. LADANYI: And this hadn't been built yet, has it? It is under construction?

MR. IRVINE: It has not been built yet, that's correct.

MR. LADANYI: So suppose this costs more a lot more

than 56.4 million.

MR. IRVINE: In the updated -- the current cost for this rate filing for distribution is classified as $61.3 million. That was updated in Staff 173 through ISD GP18.

MR. LADANYI: Thank you. So my question is back to what is a reasonable amount of money for this? Because it is justified on the basis of need; there is no benefit-cost analysis, there is no value for money analysis. How does one -- how does the Board, for example, assess whether this is the right amount of money that should be invested in something like this?

MR. IRVINE: So essentially in our investment summary document, JP18, goes through the process that we used in determining the needs and what is required for the centre.

So if you look at how JP18 is aligned today, it specifies a series of ways we go through the whole assessment.

It starts with a planning needs assessment. Through that, we make determination of what is required. In this case, we saw the need -- there are various needs in the company at the moment from the operations perspective, the integrated telecom management centre perspective, the securities perspective, and the data centre perspective.

So once we got the planning needs down pat, we go through what's called a detailed design phase. And in that detailed design phase is really where you are look at all the requirements, go through engineering, the design, to

get to the point of what are the critical components that we need that centre to be composed of in order to move forward.

Once that detailed design phase is complete, and it has been completed in this case, we then have a very good estimate of what the costs are associated with that project.

From that point, it goes to a request for proposal, and from that point we get those back, and then it goes to the construction phase.

MR. LADANYI: Thank you. In this business people are sometimes concerned that utilities that are essentially under cost of service whereby they come to the Board and tell the Board what something costs have a tendency to put into buildings, a lot of nice-to-have type of features.

And how are you sure that this is really absolutely everything is necessary that you have in this integrated system operation centre, there is not some additional things being added by people who think it would be nice have this or nice have that? It is very difficult for the Board to assess a project like this. What would be your response to that?

[Witness panel confers]

MR. IRVINE: Essentially in this case what was done is, first of all, what we're building isn't just a -- it's not just a building,; it's a control centre and a data centre, which does bring into play some different components than, say, if we were building an office

building or something of that nature.

So those are some differences taking into consideration of what is required. When you are building a data centre and a control centre, the needs and requirements are slightly different, in that we need to have redundant power supplies, duplicated compute hardware, so it is different than what the office structure would be.

MR. LADANYI: Thank you. I'll go to another subject now.

Could you turn to Undertaking JT2.13? And here we're talking about savings from interval meters. And as I read this, there's not much of a saving; is that right?

MR. MERALI: That is correct.

MR. LADANYI: Can you explain further -- I really -- because I think the public were told that there was going to be a lot of savings, a lot of advantages from having integral meters, or Smart Meters, and that the utilities will be able to get additional information that would help them with operations, perhaps operate their system more efficiently, and yet this doesn't seem to be materializing, so this is just -- not that this fully covers the subject, but you were closer to it than I am.

Can you explain to me why you are not seeing savings that we were told we were going to see?

MR. MERALI: Sure, and this interrogatory response is really speaking to the delta of additional customers that could be right on time of use beyond the roughly million-two that we have already on time of use.

So as the cellular companies expand their network coverage, it is typically our experience that they are not taking entire areas and putting a brand-new area on the grid. These are very remote parts of Ontario which currently do not have cellular coverage which are slowly, incrementally being added to, or network gear is being replaced so we can get that one additional house at the end of the -- you know, end of the road or end of the street, so based on the nature of the 5,000 roughly accounts that are being migrated to time of use on an annual basis, it is not materially reducing our manual meter-reading costs, so just to clarify, this is to -- this is about the incremental, every year, not the entire population.

MR. LADANYI: I understand that. I was only using this undertaking to --

MR. MERALI: Yes.

MR. LADANYI: -- refer to in the question.

Since I have you answering questions, maybe we can turn to my last question, which is tab 4, Energy Probe 4.

And here we've asked you about the impact of the Fair Hydro Plan on low-income energy assistance program. And it's got no impact.

MR. MERALI: Yeah, last year we didn't see a material reduction in requests for LEAP funding associated with the Fair Hydro Plan.

It was sort of early days, so to speak, in terms of its rollout and timing of the year, so the Fair Hydro Plan came into effect in July. People started really seeing the

benefits in the third quarter. LEAP is primarily a tool used to help customers right at the period of being disconnected, and we were into Q4, Q1, where disconnections were not occurring, and even most of Q2, so I think the long-term effects associated with Fair Hydro Plan and LEAP are still TBD.

MR. LADANYI: It is too early to tell, you're saying, but there might be some savings?

MR. MERALI: There could potentially be some savings over the longer-term. We still -- I would not envision a scenario where the OEB-prescribed amount of, I believe it's .12 percent of distribution revenues to put into a fund for LEAP would accommodate our needs, because we have historically spent over 200 percent of the prescribed amount.

MR. LADANYI: I'm going to ask just one more question, Mr. Berardi. Just to be sure, your shared-services organization does not provide any services for affiliates. You are just sharing services within Hydro One Networks; is that right?

MR. BERARDI: We actually shared services for Hydro One Limited. We provide services to Hydro One remotes and Hydro One telecom as well.

MR. LADANYI: And you are charging those services that you are providing at the, what, at market rates, at fully allocated cost basis?

MR. BERARDI: What we charge Hydro One telecom and Hydro One remotes is consistent with the Affiliate

Relationship Code, so depending on the type of activity, so in my area of accountability I have supply chain, fleet, services, also have facilities and real estate, so we would charge our affiliates, in this case, our subs, our subsidiaries, Hydro One telecom and Hydro One remotes, accordingly.

MR. LADANYI: One more question, sir. Very good. So as I understand it from the Affiliate Relationship Code, these services are provided under five-year contracts, so I assumed you have a five-year contract to provide services, for example, to Hydro One remotes and that it has to be renewed for another five years?

MR. BERARDI: I'm not sure if they're five-year contracts or not. We do go through a process on an annual basis to review the types of services that are provided, and we go through that process annually. I'm not sure that they're five-year contracts.

MR. LADANYI: Okay. And the ratepayers normally are concerned that a regulated utility that is providing services to affiliates would be providing it at less than fully allocated costing, which would consist of a subsidy of affiliates by the regulated utility. You understand that? So I'm glad you're following Affiliate Relationship Code. I don't think we can test it right now, and I'll take your word for it. Thank you very much.

MR. BERARDI: Thank you.

MR. QUESNELLE: Thank you, Mr. Ladanyi.

Mr. Segel-Brown? Oh, we've got a change in order?

MS. GIRVAN: Yes, sorry, change in order. I have some obligations this afternoon, so --

MR. QUESNELLE: Okay.

MS. GIRVAN: -- thank you very much.

MR. QUESNELLE: Ms. Girvan.

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

MS. GIRVAN: Good afternoon, panel. My name is Julie Girvan, and I'm a consultant to the Consumers Council of Canada. So the first question is -- and we've spoken about this -- I think we spoke about it earlier, maybe in the technical conference. I just want to make sure your position is still the same. So with respect to the Avista acquisition by Hydro One, there is no plan to share any services going forward during the rate plan term?

MR. QUESNELLE: Can we mark your compendium while we're waiting for the witness?

MR. SIDLOFSKY: That will be Exhibit K9.2.

MR. QUESNELLE: Okay.

**EXHIBIT NO. K9.2: CCC CROSS-EXAMINATION COMPENDIUM FOR HONI PANEL 6**

[Witness panel confers]

MR. BERARDI: We do not have in our five-year application in front of the Ontario Energy Board any integration with Avista.

MS. GIRVAN: And is it something you're looking into?

MR. BERARDI: Not at this point in time.

MS. GIRVAN: No plans to look into that at all?

MR. MERALI: Until the transaction officially closes

we're prohibited by federal anti -- don't quote me on the exact legislation, but there is some anti-competition legislation that says we can't work with Avista to look for synergies and things of that nature until the transaction officially closes.

MS. GIRVAN: Okay. All right. Thank you.

Now, I know that you're not the finance panel, but I want to take the sort of areas of responsibility that you have, and I'm trying to follow how the common corporate costs flow through to the overall O&M budget.

So you will see in my compendium, the first on page 2 sets out over all O&M expenses. And within the context of that schedule there is a common corporate cost which included, if you turn to the next page, is information technology, common corporate functions and services, et cetera.

And on page 3 of the compendium sets out the total amount of common corporate costs for transmission and distribution. So do you see that?

MR. NETTLETON: Sorry, what page, Ms. Girvan?

MS. GIRVAN: On page 3 of the compendium. The pages are at the bottom. There we go.

MR. NETTLETON: Thank you.

MS. GIRVAN: So I'm just trying to follow how the costs that some of you are responsible for flow through to the overall O&M for the company. Do you see that?

MR. BERARDI: Yes, we do.

MS. GIRVAN: So if you look at that schedule, that

table, there is a line at the bottom that's "Other OM&A", and from what I understand, that is largely capitalized overheads. Is that correct?

MR. BERARDI: I'm not sure.

MS. GIRVAN: You are on the same mic so you have to...

MR. BERARDI: I'm not sure what that is. We're struggling because this is not our area of accountability.

MS. GIRVAN: Yes, I realize that. I guess I'm just trying to flow through the numbers. So just take it subject to check, which I understand that that line includes capital overheads, indirect depreciation, and other non-recurring expenses.

MR. BERARDI: Subject to check.

MS. GIRVAN: Okay, great. Thank you. So if I turn to the next page, I see the common corporate OM&A costs allocated to distribution. And specifically, I see in that last column for 2018 an amount of information technology; is that correct?

MR. FROST-HUNT: Yes, I see that.

MS. GIRVAN: So again we have a forecast here of 186.3 million for those costs, subject to this adjustment at the bottom of other OM&A; do you see that?

MR. FROST-HUNT: Yes.

MS. GIRVAN: Coming up with 53.9 million of OM&A related to common corporate costs.

MR. FROST-HUNT: Yes, I see that.

MS. GIRVAN: All right. But in the context of that, you have, with respect to information technology,

80.4 million.

MR. FROST-HUNT: Yes, that is correct.

MS. GIRVAN: And I'm assuming again that's because you are going to capitalize some of those costs. Is that your understanding?

MR. FROST-HUNT: That is not my understanding. I cannot speak to the other OM&A row in this table.

MS. GIRVAN: Okay. So at the end of the day, we have 53.9 million in common corporate costs and we see that in the overall O&M expenditures on page 2 of the compendium of 53.9 million. Do you see that?

Okay. So when I take -- I'm going to now turn to the evidence related to outsourcing and I think this is yours, Mr. Berardi, your evidence. And that's found on page 10 of the compendium.

MR. BERARDI: Yes, I have that.

MS. GIRVAN: So this refers to the fact that Hydro One -- and it says this on the next page -- relies on two main outsourcing arrangements in the operation of its businesses, one with NRG and another with Brookfield Asset Management; that's correct?

MR. BERARDI: That's correct, but just to correct it, it is Brookfield -- it's BGIS, Brookfield Global Integrated Systems.

MS. GIRVAN: Yes, I've seen that reference before. So the amounts that actually are subject to those arrangements can be found on pages 19 and 20 of the evidence.

MR. NETTLETON: Sorry, of your compendium?

MS. GIRVAN: Yes, sorry, of my compendium, my evidence.

And what I'm trying to reconcile here is -- the first thing is, from what I understand, a portion of the NRG contract related to customer care has expired in February; is that correct?

MR. MERALI: That is correct.

MS. GIRVAN: And the back office services, which are the other component to that contract, expire December 31, 2019?

MR. BERARDI: That's correct.

MS. GIRVAN: So what I'm struggling with is, first of all, you've assumed, I guess in the context of projecting your O&M over the course of the rate plan, that this will continue -- these contracts will continue; is that correct?

MR. MERALI: I think it's different for the respective areas. So with respect to customer, I think we've discussed in this hearing that we in-sourced the operations subsequent to the expiry on February 28th.

MS. GIRVAN: Okay.

MR. FROST-HUNT: The information technology will continue.

MS. GIRVAN: It will continue. So what I'd like to do is -- so you have $94.7 million related to the NRG fees. How does that translate back into the schedule that I was relating to earlier?

So for example, information technology services. If you go back to page 4 of the compendium, it says

$80.4 million. However here, information technology services, the amount is $30 million.

MR. FROST-HUNT: You referenced page 4?

MS. GIRVAN: Um-hmm, yes.

MR. FROST-HUNT: The Inergi arrangement is only a portion of the overall OM&A costs allocated to distribution.

MS. GIRVAN: Okay. But if the Inergi arrangements expire at the end of 2019, what are your plans?

MR. FROST-HUNT: We've recently extended our arrangement with Inergi, such that it now expires in 2020.

MS. GIRVAN: Okay, and is that -- which element of the contract?

MR. FROST-HUNT: Information technology.

MS. GIRVAN: What about the other back office services?

MR. BERARDI: It really depends on each one. So if you take a look at the Inergi contract, it's made up of, as Mr. Frost-Hunt indicated, information technology. But there's also some other components in there, for instance settlements. There's also supply chain, there is payroll, finance and accounting and customer service operations.

So depending on which statement of work we're talking about, they have different -- we have a different process for each one of those.

MS. GIRVAN: So there are different assumptions going forward for each of those areas?

MR. FROST-HUNT: That's correct.

MS. GIRVAN: And it's not necessarily going to be steady state going forward? You might enter into a contract with another service provider at a lower cost; is that correct?

MR. BERARDI: That is a possibility.

MS. GIRVAN: Is that something that you're looking to do?

MR. BERARDI: We're assessing each one of our statements of work in order to drive value both internally and for our ratepayers. So, for instance, if you take a look at supply chain, which I know, or source to pay -- it is known as source to pay within the contract. We're driving different changes because we today are different in the way we actually procure services.

So we're asking our outsourcer to provide those value-added services, so we are making significant changes in that area. And Mr. Merali talked about some of the changes he's making in the customer service operations as well.

MS. GIRVAN: Okay. So this $39 million related to customer service operations will be -- that's taken in-house now?

MR. MERALI: That is correct.

MS. GIRVAN: Okay. And you mentioned, Mr. Berardi -- sorry, you mentioned the areas that you are responsible for. Where in these lines are those -- do I find those? I think you said supply chain?

MR. BERARDI: That's the accounts payable piece.

MS. GIRVAN: Okay. All right. Thank you. And --

MR. FROST-HUNT: Sorry, with regard to the Inergi arrangement, I believe I said we extended to 2020. It is actually March 2021, if I could correct my statement. Thank you.

MS. GIRVAN: Okay, thank you. And are there different fees with respect to that new arrangement other than those that are set out here?

MR. FROST-HUNT: With regard to information technology? We've made improvements to our arrangement, such that we're able to lower our OM&A forecast going forward.

MS. GIRVAN: But that's not included in your rate plan?

MR. FROST-HUNT: It is reflected in SEC 70, the most recent OM&A forecast.

MS. GIRVAN: Okay. So that -- the new arrangement with Inergi is included in the cost of service?

MR. FROST-HUNT: That is correct.

MS. GIRVAN: Okay, great. Thank you.

So Mr. Merali, I just had a few questions on the specific service charges, and we've talked about these before, and I realize that you've been directed by the Board to do a study, and we've talked about this before. You've been directed by the Board to do a study, and you've proposing new charges based on that study; is that correct?

MR. MERALI: That's correct.

MS. GIRVAN: Okay. And I think we'll talk about the underlying cost associated with these services with the

next panel; is that correct? Is that...

MR. MERALI: Correct. Mr. Boldt will be able to provide details on a time study that was completed.

MS. GIRVAN: Okay. So if you could just turn to some of those service charges. I've set them out on pages 24, 25, throughout the compendium. And I think we had a discussion about this in the technical conference, and you can appreciate from the customer's perspective that we might have concerns about the level of some of these charges.

MR. MERALI: Yes, I can.

MS. GIRVAN: Okay. And I guess I would say specifically with respect to low-income customers because, for example, some of the fees go up extensively in 2018 relative to the currently-approved rate, correct?

MR. MERALI: Correct, the last time the rates were reviewed to my knowledge was 2006, so there hasn't been an adjustment made to these fees in 12 years, so some of the changes are quite significant.

MS. GIRVAN: Okay. And I guess what I would ask is -- let me -- sorry. With respect to these charges will you have an opportunity to implement payment plans for customers with respect to these charges? I know you have payment plans currently with respect to your overall bills, and I guess my concern would be a customer might get a bill for $800 subject to one of these charges at a given point in time.

And I'm just wondering what your plans are in terms of

mitigating the impacts of some of those charges?

MR. MERALI: Yes, we would allow a customer to put these service charges into an installment plan, should they choose to.

MS. GIRVAN: Will you let the customers know that?

MR. MERALI: We do disclose. I mean, I'd have to look at the specific wording, but we do let customers know that any outstanding charges can be put into an arrears management plan.

MS. GIRVAN: Okay, all right, thank you.

And just quickly, were there some of these charges that -- and maybe it is for the next panel -- that you are compelled to implement because of the OEB?

MR. MERALI: My understanding is we're compelled to implement all of them, so the OEB 2016 electricity distributor's rate handbook outlined specific charges. Hydro One's practice has been to charge for some of these charges and not to charge for others. But subject to the direction to undertake a time study and update all of the information, we have learned that there are some charges which historically we have not been charging for and we are, to my knowledge, obligated to charge customers for those amounts.

MS. GIRVAN: But the specific charges that you have set out in your application are derived from your cost study; they are not mandated by the Board.

MR. MERALI: My understanding -- and panel 6 are the experts on this -- is that we are mandated to charge the

actual cost. So we undertake a time study, that's what the numbers come out to be, and we are obligated to charge that amount.

MS. GIRVAN: Okay, all right, thank you.

MS. ANDERSON: So just so there's heads-up for that panel, I wasn't sure of the extent to which that will be explored in the area, but I know I'd be interested in finding the reference that Hydro One was relying on for the belief that there's something that's mandatory here, so when that panel comes up, if they can point to the specific reference where the OEB has mandated the charges or anything else related to them.

MR. MERALI: We'll make sure they have the heads-up.

MS. GIRVAN: That would be helpful, thanks.

MR. NETTLETON: I think they already have.

MS. GIRVAN: Okay. I just had a few questions with respect to fleet management, and Mr. Ladanyi was talking about this.

So the fleet management costs are found on page 32 of the compendium. And I think, Mr. Berardi, you were the one who said because of the telematics project that you expect to find efficiencies; is that correct?

MR. BERARDI: That is correct. That can be found in their productivity exhibits.

MS. GIRVAN: Okay. But I see in 2018 the fleet management going up. And that's on page 32 of the compendium.

MR. BERARDI: So the -- if you are referring to 2018;

is that correct?

MS. GIRVAN: Yes.

MR. BERARDI: So the $144.7 million?

MS. GIRVAN: Yes.

MR. BERARDI: That was a forecast at March 31st. With respect to, you know, going back to my earlier comment that in 2017 we went through a fleet right-sizing utilizing our telematics utilization information and we reduced our fleet by 10 percent, so that number relates to the 8,000 pieces of equipment. We do have a revised forecast, and I'd like to submit that as an undertaking, if you would agree to that.

MS. GIRVAN: Yes, you mean, you're asking to reduce the cost of service to reflect the reduction? That would be great.

MR. NETTLETON: I think that's the first time I've heard the witness give the cross-examiner an undertaking. Well done, Mr. Berardi.

MR. SIDLOFSKY: I'll jump all over that by giving that number J9.3.

**UNDERTAKING NO. J9.3: TO SUBMIT THE REVISED FORECAST.**

MS. GIRVAN: And can you just roughly explain what the difference might be?

MR. BERARDI: So getting back to some of the discussions around productivity and some of the tools we've --

MS. GIRVAN: Yeah, I guess I'm just looking for what's the ballpark range?

MR. BERARDI: The ballpark range?

MS. GIRVAN: Of the reduction. Or should I just wait for the undertaking?

MR. BERARDI: Let's wait for the undertaking. I don't want to guess at the number.

MS. GIRVAN: Okay, great. Thank you.

Okay. If you could please turn to page 36 of the compendium. So if you look at the part that's highlighted there with the black mark -- sorry, at the top, yeah. So it says here:

> "The fleet is at 39 percent net book value to original capital value where industry standards established through a combination of Canadian utility fleet manager workshops, direction from our fleet management companies, and industry experts suggest a 45 percent optimum level."

Can you explain that to me?

MR. BERARDI: I really don't know where this comment came from. I can -- I can walk you through what we're doing today with respect to our fleet. I'm not familiar with that comment.

MS. GIRVAN: Okay. I guess I have a question. When we were talking earlier in the proceeding and talking about poles and how certain assets are subject to an inspection, is that the way you deal with your fleet, in a sense? You don't necessarily retire vehicles if they're not ready to be retired. It is not necessarily based on the age of the asset, it's based on really the condition of the asset; is

that right?

MR. BERARDI: Yes, it's based on an asset condition assessment. It's based on wear and tear. It's based on number of kilometres driven. It's based on utilization. There's many factors that it's based on.

MS. GIRVAN: Okay. It says here that you've got this replacement program, so acquisitions 2018 to '22. Did you ever benchmark any of this in the sense of look at what other utilities do, how long do they keep their vehicles, how long -- what's the sort of annual acquisition rate? Did you look at this any other utilities doing that?

MR. BERARDI: We did not.

MS. GIRVAN: Okay. I just want to go back to that first point:

> "Our present replacement criteria are based on manufacturer's recommendations and repair history."

So you are manufacturing away from that? Is that what you're telling me?

MR. BERARDI: I think the manufacturer's recommendation is just an input to the process. We do look at individual units and base them on the condition that they're in. So we do have regular maintenance and regular asset condition assessments on each one of those pieces of equipment.

MS. GIRVAN: Okay. So how is -- when we go down to table 1 and you say 2018 you've -- you're going to replace 542 units at a cost of 29.1 million, how did you come up

with that?

MR. BERARDI: It's based on the asset condition assessment that we have conducted with each one of our fleet classes, and that's how we have come up with those units.

MS. GIRVAN: Okay. But over the period, you're increasing the number of acquisitions in each year?

MR. BERARDI: This is the acquisition piece. What you're not seeing is the disposal. With those acquisitions, we are also disposing at a very similar rate. So our plan is to stay at the new 7,200 baseline that we've established.

MS. GIRVAN: Okay, thank you. Could you please turn to page 37? And this is about your helicopter policy. I'm bringing this to your attention just because I was approached by a customer and I work for a consumer group who was concerned about your policy. And when I read through the policy, and if you can turn to page 39, it says:

> "A manifest is not required for helicopter flights in support of approved work programs for the individual lines of business and responding to an emergency."

And this particular customer was concerned that the helicopter that was being used to service, I think it was an island somewhere up north, the crew went out and were working on the asset, and this helicopter left and came back with someone's lunch.

So I just want to make sure that you have something in place to ensure that there is an efficient use of the helicopters. And what concerned me was that in the normal approved work programs, there doesn't seem to be any requirement for a manifest.

MR. BERARDI: This helicopter policy does not represent what Hydro One does in accordance with Transport Canada.

We are bound by Canadian aviation regulations and our policies, our procedures, are based on Canadian aviation regulations that we are certified to fly and maintain our helicopter fleet as per Transport Canada.

MS. GIRVAN: I guess I was more concerned about the efficient use of the helicopter.

MR. BERARDI: Can you clarify your question, please?

MS. GIRVAN: Earlier, I guess I was talking about how the helicopter was used to go get lunches for the staff, and I'm just wondering what you have in place to sort of prevent that.

MR. BERARDI: I can't comment on that specific example. I can tell you what we use our helicopters for and they're in support -- my colleague, Brad Bowness, was here to talk about work execution on the distribution lines. Our helicopters are used for line patrols, for material slinging, for moving crews throughout the province. That's what our helicopters are used for.

MS. GIRVAN: How do you ensure productivity in the context of the use of the helicopters?

MR. BERARDI: We do have helicopter rates that we -- and we also have utilization hours per helicopter and we cost that out appropriately.

MS. GIRVAN: Thank you, I'll move on. Now, just in the context of -- if you could please turn to page 41, I'm just trying to ensure that in the current -- I guess it's the update in Exhibit Q that you've taken into consideration the Fair Hydro Plan in terms of the ultimate bad debt expense. And I think on page 42 it says this, but I just want to be sure that you've made an adjustment to the bad debt expense to reflect the Fair Hydro Plan.

MR. MERALI: Correct. I believe as part of this interrogatory response and Mr. D'Andrea, I believe, mentioned it in the opening panel's remarks that we have reduced our bad debt expense by approximately $3 million as it relates to the Fair Hydro Plan.

MS. GIRVAN: Because what it says in this interrogatory is cash working capital impact and a reduction to OM&A as a lower bad debt expense. Where do I see the cash working capital, in fact?

The 2.9 million specifically relates to lower bad debt expense, is that correct?

MR. MERALI: That is correct.

MS. GIRVAN: Okay. And that would come out of the OM&A line?

MR. MERALI: Correct, and one point of clarification or heads-up that my colleague, Mr. D'Andrea, will likely mention is that associated with the Fair Hydro Plan, there

is reduction in bad debt expense. But there is also a forecasted reduction to late payment charge revenue.

So as a result of customers, you know, approved affordability and less amount outstanding, it reduces working capital, it reduces bad debt expense, but it also reduces late payment charges which is what our external revenue uses to offset rates.

MS. GIRVAN: Okay. Could you please turn to page 46 -- actually 47, please. This is with respect to call centre, which I understand is your responsibility. Have you, in 2018, have you reduced the call centre operations to reflect the introduction of the Fair Hydro Plan?

MR. MERALI: We have not reduced as a result of the Fair Hydro Plan in 2018.

MS. GIRVAN: And why not?

MR. MERALI: I guess there's a variety of factors that go into our context and our operations cost for 2018, and I'll just sort of state them briefly. I can go into more detail if you like.

The first two months of the year were run under the original energy outsourcing contract, so the costs were fixed costs associated with that outsourcing agreement.

We had some transition costs associated with bringing the contact centre in-house. And our current run rate or operating rate of the contact centre post in- sourcing, our year-end forecast is in line with the $44 million outlined here.

MS. GIRVAN: So included in the 44 million are

transition costs related to bringing it in-house?

MR. MERALI: Our year-end forecast, inclusive of all the costs incurred this year, is $44 million.

MS. GIRVAN: Does that include transition costs?

MR. MERALI: That would include some transition.

MS. GIRVAN: Could you let me know, maybe through an undertaking, what the level of transition costs are included in that 44 million?

MR. MERALI: Sure.

MR. SIDLOFSKY: That will be J9.4.

**UNDERTAKING NO. J9.4: TO PROVIDE THE LEVEL OF TRANSITION COSTS INCLUDED IN THE 44 MILLION TO BRING THE CONTACT CENTRE IN-HOUSE**

MS. GIRVAN: I just have one more question. There was reference earlier to the integrated system operation centre and from what I understand, there's now been an increase to the cost associated with that of about $5 million. Is that correct?

MR. IRVINE: There's -- in reference to the updated ISD that was posted in February of 2018?

MS. GIRVAN: Yes.

MR. IRVINE: Total cost of project increased from a total of 130 to $138 million, of which 50.07 percent would be attributed to distribution.

MS. GIRVAN: Okay. And what was the reason for the cost?

MR. IRVINE: That was a result of what I spoke to earlier in the detailed design process, where the costs

were refined to a more accurate figure after the detailed design, engineering specs, drawings were all completed.

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

MR. QUESNELLE: Thank you very much. Mr. Segel-Brown, are you up next?

MR. SEGEL-BROWN: I am. How late do you intend to go today?

MR. QUESNELLE: I was actually going to take a ten-minute break and then we'll start with you, if that's all right, and we'll go to -- well, we'll see if we can finish off with you today. How's that?

--- Recess taken at 4:13 p.m.

--- On resuming at 4:27 p.m.

MR. QUESNELLE: Mr. Segel-Brown.

**CROSS-EXAMINATION BY MR. SEGEL-BROWN:**

MR. SEGEL-BROWN: Hello, my name is Ben Segel-Brown, and I represent the Vulnerable Energy Consumers Coalition.

Could we turn to page 3 of my compendium.

MR. SIDLOFSKY: Just before we do, Mr. Quesnelle, you and the other members should have a copy of Mr. Segel-Brown's compendium, and we'll mark that as Exhibit K9.3.

MR. QUESNELLE: We have it. Thank you.

**EXHIBIT NO. K9.3: VECC CROSS-EXAMINATION COMPENDIUM FOR HONI PANEL 6.**

MR. SEGEL-BROWN: So my first questions relate to the retailer requested off-cycle read charge. So as I understand it, this charge applies where a retailer requests the enrolment or dropping of a customer at a time

other than the normally scheduled meter read; is that correct?

MR. MERALI: That's correct.

MR. SEGEL-BROWN: And the charge does not apply if the customer has a functioning smart meter.

MR. MERALI: Correct. If we can obtain their read automatically via the AMI network, no charge is -- there is no charge.

MR. SEGEL-BROWN: Does a charge apply in other circumstances where Hydro One has to do an off-cycle meter read, such as when a tenant pays their electricity bill on move-out?

MR. MERALI: Subject to confirming through the miscellaneous charge exhibit that we referenced earlier, I don't believe so, but I can -- all the charges are outlined in that table.

MR. SEGEL-BROWN: Okay. And it's your understanding, subject to check, that there is no charge for an off-cycle meter read in other circumstances?

MR. MERALI: I can check for you right now if you'd like, sir. So there is charge code 15, special meter reads. I mean, after a quick check I think charge code 15 might be the only one that could apply in that scenario.

MR. SEGEL-BROWN: Okay, so it's not the customer's responsibility to ensure connectivity for their smart meter, is it?

MR. MERALI: No, it is not.

MR. ENGELBERG: Why would we treat customers who

happen no not have connectivity for their smart meter differently from customers who do have connectivity? How is that a fair treatment between those customer classes -- groups?

MR. MERALI: So I think we've talked about this subject in sort of different ways with respect to the miscellaneous service charges. From a customer-service standpoint if we don't -- are not obligated to charge customers for all of these specific charges, I think that is a more appropriate way to go in some circumstances, but I think panel 6 will get into the specificity about our understanding about what we're obligated to charge for and what we are not obligated to charge for. Panel 7. Sorry, I keep saying panel 6.

MR. SEGEL-BROWN: So that the answer I heard there is that you believe that you are obligated to charge this fee because there is associated cost to you?

MR. MERALI: Correct.

MR. SEGEL-BROWN: Okay. Could you turn to tab 3, which is page 7 of the PDF. So this is the charge related to move-in at a vacant premise. Can you confirm it is currently not your practice to charge for a reconnection at time of move-in?

MR. MERALI: Correct.

MR. SEGEL-BROWN: And can you confirm that going forward it is your practice at time of disconnection to install a meter with remote disconnect and reconnect functionality?

MR. MERALI: Not in all cases. In select cases.

MR. SEGEL-BROWN: In what circumstances is a meter with remote disconnect functionality installed?

MR. MERALI: So there's a number of factors that go into the ultimate decision-making process. First is meter availability. We only have roughly 5- to 10,000 remote disconnect meters available. The second and one of the key drivers is with respect to the communications reliability of that specific meter, so as we've discussed, some meters have better communication capabilities than others, and if the meter communication isn't rock-solid, we would not install a remote disconnect-capable meter at that premise.

MR. SEGEL-BROWN: Okay, if a customer moves into a premise with a remote disconnect and reconnect meter, does this charge apply?

MR. MERALI: We are not currently charging for this charge, so right now the answer would be no.

MR. SEGEL-BROWN: Well, currently you are not charging for any reconnection, but in the future where you have remote reconnection capability, would you be charging for reconnection when it's done remotely rather than with a truck row?

MR. MERALI: Subject to check, I believe the answer is no.

MR. SEGEL-BROWN: You would not be charging where it could be done remotely?

MR. MERALI: Correct.

MR. SEGEL-BROWN: Why should the new customer be

charged for reconnection when the disconnection is not attributable to that new customer?

MR. MERALI: This goes back to my earlier comment about clarity on what we are obligated to charge customers for and not obligated, which specific service charges.

MR. SEGEL-BROWN: Okay. What is the primary reasons why customers fail to pay their hydro bills?

MR. MERALI: The primary reason why -- is there a reference, or I'm just -- can you maybe provide some additional clarity so I can provide an adequate response?

MR. SEGEL-BROWN: For example, do customers primarily refuse to pay because they are unable to pay or because they dispute a charge or because they're unwilling to pay? Have you done any analysis to understand why customers are not paying their hydro bills for -- which feeds into your bad debt expense?

MR. MERALI: So there's a number of factors that underlie bad debt expense, so there's things such as bankruptcies, so businesses frequently go out of business or file for bankruptcy protection, and that would cause us to incur a bad debt expense.

There are also customers who get disconnected for non-pay, which I would say is, you know -- would likely be an affordability issue, who do not ultimately pay their bill.

And broadly speaking, a third category would be customers who move out and fail to pay their final bill upon move-out.

MR. SEGEL-BROWN: So I gather -- I'm concerned with

residential customers primarily. So I gather from that that the primary causes for residential customers are non-payment, which is usually attributable to affordability or failing to pay the last bill upon move-out.

MR. MERALI: Those would be the primary drivers. There are other smaller drivers, such as a deceased individual and lack of clarity around the estate, but those would be the primary drivers.

MR. SEGEL-BROWN: For customers who are unable to afford their hydro bills, do you believe that they would be able to afford to pay their outstanding bill, the disconnection charge, and the reconnection charge where that reconnection charge seems to be in the order of over $800 alone?

MR. MERALI: So to clarify the $800, that is only an after-hours reconnection charge, so that would apply if a customer, let's say, were disconnected and contacted us on a Saturday and insisted or would like to be reconnected on that Saturday or an off day. I believe the standard reconnection charge is 160 -- 165 or 185. I can just try and find it here. But it's not $800.

MR. SEGEL-BROWN: Ah, okay. Yes, I copied the wrong chart there.

Still, the same question stands, where the customer is going to have their outstanding bills, the disconnection charge, I'm not sure what the magnitude of that was, and then there is a $185 reconnection charge.

Do you think that residential customers are likely to

be able to afford to pay those charges?

MR. MERALI: It certainly does not help with affordability.

MR. SEGEL-BROWN: If those costs are incurred by Hydro One but not recovered because the customer never reconnects, who bears those costs?

MR. MERALI: It would ultimately go into bad debt expense, which would be borne by all ratepayers.

MR. SEGEL-BROWN: What efforts has Hydro One made to ensure that customers in arrears are aware of programs which may be available to support them, like Ontario Energy Support Plan, LEAP, Affordability Fund, and so on?

MR. MERALI: We've done a number of items in that regard actually, and a number of items are on the evidentiary record, but I'll cite a few here.

We have really modified and enhanced our overall collections program to provide significantly more outreach to customers, more notifications, letters, calls, to inform and educate them about the various programs and services able to assist. That would be sort of one of the primary mechanisms through which we educate customers.

We've also undertaken to give our contacts and our staff specialized training in collections, providing advice to customers, helping to negotiate affordable payment plans. So both through our written correspondence with customers, our automated phone correspondence, our website, a variety of channels we use to educate and inform our customers.

MR. SEGEL-BROWN: I'm glad to hear that you're doing all of that. I wasn't aware of it. Has Hydro One considered alternative approaches which would engage social assistance in helping customers to ensure they pay what they can, even if that may not be...

MR. MERALI: So we do work with social service agencies. We have social service agency team within the contact centre, and we have a network of social service agencies that we work with on a regular basis around the province. The -- we call them SSA, social service agencies. They are a key component in helping to enrol customers in our LEAP program, Low-income Emergency (sic) Assistance Program.

So we have a -- I'd say a good relationship with our social service agencies to try and find suitable solutions for customers who are struggling with affordability.

MR. SEGEL-BROWN: Thank you. So if we could turn to tab 7, which is page 22, in this interrogatory, Board Staff state that there are approximately 150,000 meters that require manual readings. Can you confirm that number is correct?

MR. MERALI: If you can give me a moment, I can see if I have -- I believe it's in the 110,000 range at this time.

MR. SEGEL-BROWN: And what portion of Hydro One's meters does that represent, approximately?

MR. MERALI: Roughly 1.3 million customers, so 7 or 8 percent, off the top of my head.

MR. SEGEL-BROWN: Has this number changed

significantly since the last Board cost-of-service proceeding?

MR. MERALI: The number overall has come down over time. I believe Hydro One has made applications to the Board for an exemption from time of use rates for certain customers with non communicating meters.

But the number has slowly come down slowly over the years, although I don't have the historical data with me.

MR. SEGEL-BROWN: Could you undertake to provide the historical number of meters that still require manual readings?

MR. MERALI: Yes.

MR. SIDLOFSKY: That will be J9.5.

**UNDERTAKING NO. J9.5: TO PROVIDE THE HISTORICAL NUMBER OF METERS THAT STILL REQUIRE MANUAL READINGS**

MR. SEGEL-BROWN: I believe it was mentioned earlier that these meters are the most remote meters. Would I be correct to assume that the cost associated with doing manual reads is therefore high?

MR. MERALI: That would be correct. Remote and also topography plays into it a little bit. So there are occasions where it may not be remote. However, topography, a hill, foliage, the meter location on the premise -- so there's a variety of factors, but remoteness is the primary one.

MR. SEGEL-BROWN: Is there anywhere on the record where you've stated the cost associated with those manual meter reads?

MR. MERALI: I believe in our customer care OM&A exhibit, we do outline the cost for meter reading. I think that's C1, tab 1, schedule 5.

MR. SEGEL-BROWN: Do the areas which cannot be read remotely still have smart meters, or...

MR. MERALI: Yes, the vast majority have smart meters. They just can't communicate.

MR. SEGEL-BROWN: What portion of those customers have unreliable mobile coverage as opposed to no mobile coverage?

MR. MERALI: So if there is unreliable mobile coverage, we will -- and we have the network equipment to support collecting the reads, we will attempt to get the read automatically. And only if we are unable to get the read automatically is when we would schedule that meter to be read manually.

MR. SEGEL-BROWN: Hydro One's responses on this point gave the impression that meters have to communicate at or near the time of measurement. Did I understand that correctly? So a meter cannot communicate a measurement at a subsequent point in time?

MR. MERALI: So there's a billing window for customers, a period of time, a number of days through which a customer's bill is ultimately produced and we seek to receive an actual meter read during that -- what we call the bill window, so that we can bill the customer based an their actual usage, which is also part of the requirement for the Ontario Energy Board's billing accuracy targets.

So we attempt to receive an actual meter read in the window.

MR. SEGEL-BROWN: Okay. What portion of customers with smart meters have wired telecommunication services?

MR. MERALI: Sorry, could you clarify?

MR. SEGEL-BROWN: Like do they have home internet or...

MR. MERALI: I would not have that information available.

MR. SEGEL-BROWN: Has Hydro One does any analysis of considering using alternative means of communicating for meters which transmit through wired connections or through femtocells?

MR. NETTLETON: Mr. Chairman, I thought the previous question was answered to say that Hydro One has not done that work, or has that information. So I'm not sure how we can follow up.

MR. SEGEL-BROWN: I took the answer to mean that he does not know whether the customers who have non communicating smart meters have functioning wireline telecommunication services.

I didn't hear an answer regarding whether they have done an analysis of alternative means of communications for those smart meters.

MR. MERALI: I believe our asset management team has done analysis on a number of different technologies and mechanisms through which to receive the automated readings. However, I'm not a subject matter expert in that area.

MR. SEGEL-BROWN: Would you be able to -- I think it is a little too late in the process to request that.

Regarding the advance metering initiative upgrades to leverage expanding mobile networks, what portion of the additional 26,436 smart meters that will be connected would have been connected even without Hydro One undertaking additional investments?

MR. MERALI: Would you mind pointing me to that reference?

MR. SEGEL-BROWN: It's at page 38 of my compendium, I believe -- no, sorry. It's -- I'm afraid I'm going to have to go back to the original source document.

It is from the description comparable to this one for the program which is intended to take advantage of expanding mobile networks to connect additional smart meters, but I can find the particular reference from Exhibit B2, if that would be helpful.

MR. MERALI: I mean, I can speak a little bit in generalities. But if cellular communication becomes available we would need to install what we call collectors and repeaters in the region for us to create a -- what we refer to as a mesh network, so that the reads could ultimately get back to a point where they could be communicated via cellular to our head-end system.

MR. SEGEL-BROWN: So my question was some smart meters will be reached by the expansion of the carriers' networks alone and some additional customers will be reached by you making additional investments in repeaters and collectors.

It wasn't possible for me to determine from the description of the investment how many extra customers are being connected as a result of Hydro One's investments.

Perhaps the best way to address the one is if I could have an undertaking for you to see if you have that figure regarding how many -- or -- because the figure that's provided with the investment description is a forecast of the total number of additional customers who will be connected; it doesn't distinguish between those who will be connected regardless and those who will be connected as a result of the investment.

MR. MERALI: Sorry, just thinking it through, I mean, expanded coverage on its own does not allow -- cellular coverage on its own does not allow a meter to communicate. You need our infrastructure in there as well, so they go hand in hand.

MR. SEGEL-BROWN: So your meters don't communicate directly with a mobile network.

MR. MERALI: So the vast majority of our meters communicate over what's called a -- what we define as a mesh network. And basically it's, meters can talk to other meters and sort of hop down the road, so to speak, and then ultimately there is a repeater that can aggregate a number of reads, and then it will go to a collector, and the collector will ultimately communicate with the cellular network to do what we call back-haul and take all of the reading information and download it into our head-end systems, so you need the cellular network as well as some

of our devices in order to create that environment where the reads can get back to our system.

MR. SEGEL-BROWN: Okay. Can we turn to page 35 of my compendium. So this relates to the advance metering initiative hardware refresh. I want to ask you about the second point, which states that:

> "Hydro One Distribution has acquired non-standard meter installations due to a boundary change or due to the outright acquisition of local distribution companies."

My question is, are Hydro One customers bearing the cost of standardizing meters for customers of the acquired utilities under this program?

MR. MERALI: I'm not the expert in this area, but I do know that the three acquisitions that we've completed, that they relied on different meter manufacturers, so Hydro One uses primarily Trilliant, and the acquired utilities run on Elster and Sensus technology, and Hydro One has continued to operate those systems and read those customers on those acquired -- from the acquired utilities using those legacy systems.

MR. SEGEL-BROWN: This -- the description of this investment, however, suggests that Hydro One will be upgrading those meters to standard Hydro One meters at the acquired utilities.

Can you confirm whether or not that is going to occur?

MR. MERALI: Unfortunately --

MR. NETTLETON: Mr. Segel-Brown, I'm only interrupting

because the -- again, this IR was prepared by Ms. Garzouzi. She was on the other panel. She explained the time period of this investment, and I would have thought that if you had questions about whether Hydro One acquired distribution LDCs, meters were going to be replaced, she would have been the right person, and the timing of those replacements, she would have been the right person given this interrogatory, so I'm struggling to see how Mr. Merali can provide information about the timing of asset replacements.

MR. SEGEL-BROWN: My understanding is that my questions regarding metering were referred from that panel to this panel.

MR. NETTLETON: On asset replacement?

MR. SEGEL-BROWN: On metering, I mean.

MR. QUESNELLE: I realize it is under the heading of asset replacement, Mr. Nettleton, but you can see why there may be a cross-over of understanding if it's being driven by customer request, if it's being driven by customer care, you know, drivers, as opposed to an asset management --

MR. SEGEL-BROWN: If this panel would prefer to answer by way of undertaking, consulting with the relevant person, I'd be happy to accept that.

MR. MERALI: Can you clarify the specific question so we can make sure we capture it?

MR. SEGEL-BROWN: The specific question is whether -- first, whether Hydro One will be replacing the meters at the acquired local distribution companies; and, second, whether Hydro One customers will be bearing those costs.

MR. MERALI: Okay.

MR. SIDLOFSKY: That will be J9.6.

**UNDERTAKING NO. J9.6: TO ADVISE, FIRST, WHETHER HYDRO ONE WILL BE REPLACING THE METERS AT THE ACQUIRED LOCAL DISTRIBUTION COMPANIES ;AND, SECOND, WHETHER HYDRO ONE CUSTOMERS WILL BE BEARING THOSE COSTS.**

MR. SEGEL-BROWN: Is this panel able to speak to the other aspects of this interrogatory regarding the replacement of smart meters?

MR. MERALI: I don't believe if there's details. I'm sort of reading the rest of the response here, and I'm not in a position to speak to these items.

MR. SEGEL-BROWN: Okay. When a customer receives a bill, what is the billing date? When does the clock start?

MR. MERALI: Subject to check, I believe we produce a bill, and then we allow three days for postage, and that would be the sort of Day 1, if you'd call it that, or Day Zero, and then payment terms extend beyond that.

MR. SEGEL-BROWN: So how long from the time the customer receives the bill, which is three days after you posted it, you told me, do they have to make a payment without penalty?

MR. MERALI: It's approximately 21 days.

MR. SEGEL-BROWN: How long do they have until they receive a late payment notice?

MR. MERALI: A late payment notice being like a letter or some kind of documentation indicating that they are behind on their bill?

MR. SEGEL-BROWN: Yeah, I mean, if you turn to page 29 you can see the actual steps that Hydro One goes through if it is easy to refer to those.

MR. MERALI: So I guess two different mechanisms for customers to get a response. So the first is we've deployed automated technology to provide customers who enroll a notification if their -- prior to their payment being due and then an e-mail notification if their payment is past due, so customers would -- who enroll for that service -- and so far we have approximately 150,000 customers are enrolled in that service -- would receive notification within days of missing their payment.

With respect to receiving notification in the mail, it depends on a customer's sort of history with us, but the first letters go out approximately ten days after a customer would miss a payment.

MR. SEGEL-BROWN: Okay, so how long after the time of the -- that mail notification is the disconnection notice sent?

MR. MERALI: I'd have to get you the specific timings, but there is a period of time elapsed between the various notifications and then ultimately the disconnection notice.

MR. SEGEL-BROWN: Okay, could you do that then? Could you provide me with the timelines for this process?

MR. MERALI: Sure. Now, it does vary by customer class, but --

MR. SEGEL-BROWN: Well, I'm interested in residential customers if you want to narrow it down.

MR. MERALI: Sure.

MR. SEGEL-BROWN: Undertaking?

MR. SIDLOFSKY: J9.7.

**UNDERTAKING NO. J9.7: TO PROVIDE THE TIMELINES FOR NOTIFICATIONS TO RESIDENTIAL CUSTOMERS, AND ULTIMATELY THE DISCONNECTION NOTICE.**

MR. SEGEL-BROWN: Once a customer has received a disconnection notice, if they pay their bill immediately is there any charge which is applied at that point?

MR. MERALI: Other than late payment charges which should apply, no.

MR. SEGEL-BROWN: Okay. Could we turn to tab 10, which is page --

MR. QUESNELLE: 34.

MR. SEGEL-BROWN: Hmm. It's a different tab 10. I'll skip that question, then.

I know that you are not the person to speak to regarding the actual time study, but could you explain to me why the rate amount for direct labour clerical is identified as $80 an hour before the payroll burden?

MR. MERALI: Unfortunately, that would be a question for my colleague Mr. Boldt, on panel 7.

MR. SEGEL-BROWN: All right. Those are all my questions. Thank you very much.

MR. QUESNELLE: Thank you, Mr. Segel-Brown. I think it's five to 5:00. I think we will adjourn for the day and we'll start again tomorrow morning at nine o'clock.

--- Whereupon the hearing adjourned at 4:58 p.m.