ONTARIO ENERGY BOARD

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

VOLUME:	**Volume 6**	
DATE:	**June 19, 2018**	
BEFORE:	**Ken Quesnelle**	**Presiding Member and Vice-Chair**
	Lynne Anderson	**Member**
	Emad Elsayed	**Member**

EB-2017-0049

THE ONTARIO ENERGY BOARD

Hydro One Networks Inc.

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

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Tuesday, June 19, 2018,
commencing at 9:36 a.m.

VOLUME 6

BEFORE:

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

A P P E A R A N C E S

JAMES SIDLOFSKY	Board Counsel
MARTIN DAVIES KEITH RITCHIE	Board Staff
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LISA (ELISABETH) DeMARCO JONATHAN McGILLIVRAY	Anwaatin Inc., Energy Storage Canada (ESC)
SHELLEY GRICE	Association of Major Power Consumers in Ontario (AMPCO)
MICHAEL BUONAGURO	Balsam Lake Coalition (BLC) Arbourbrook Estates
TOM BRETT	Building Owners and Managers Association, Toronto (BOMA)
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JULIE GIRVAN	Consumers' Council of Canada (CCC)
BRADY YAUCH TOM LADANYI	Energy Probe Research Foundation
ROBERT WOON	Ontario Sustainable Energy Association (OSEA)
RICHARD STEPHENSON BODHAN DUMKA	Society of United Professionals
MICHAEL McLEOD	Quinte Manufacturers' Association (QMA)
JAY SHEPHERD MARK RUBENSTEIN	School Energy Coalition (SEC)
RICHARD STEPHENSON	Power Workers' Union (PWU)

A P P E A R A N C E S

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

ALSO PRESENT:

JODY McEACHERN STEVEN VETSIS	Hydro One Networks Inc.

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

E X H I B I T S

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

Tuesday, June 19, 2018

--- On commencing at 9:36 a.m.

MR. QUESNELLE: Mr. Nettleton, any preliminary matters from yourself?

PRELIMINARY MATTERS:

MR. NETTLETON: I do, Mr. Chairman.

Last evening Hydro One filed a response to an undertaking that was provided by Mr. D'Andrea, and it was assigned -- I believe it was assigned Exhibit K2. -- sorry, J2.4, and this was in relation to the line of questioning that Mr. Rubenstein had asked Mr. D'Andrea about a Boston Consulting Group report that was referred to in Mr. Tankersley's evidence, and there was a follow-up discussion about whether there were other reports and that Mr. D'Andrea was going to go check. And the undertaking was to provide in advance of the appearance of panel 5 material created by Boston Consulting Group, and that was in respect of the question of Mr. Rubenstein at line 18 of the transcript at page 110. The question was:

> "Could you file that -- would you undertake to provide that report?"

And Mr. D'Andrea's response was:

> "If there is a report and it is subject to confidentiality then we will provide it in the proper form."

So a long way of saying we did file the report that -- and it wasn't really a report. It was more of a slide -- a presentation deck that Boston Consulting Group had provided

to Hydro One relating to vegetation management, which I believe is what Mr. Tankersley saw and had access to.

With respect to the additional report that Mr. Rubenstein was asking for, we have searched, and there is no report per se. What we have found is that there is a presentation that Boston Consulting Group and Hydro One's senior management prepared together to Hydro One's board of directors. And this was -- it is something that, again, panel 5 will be able to speak to, Mr. Bowness will be able to speak to, in terms of the exercise that was carried out, but it was very much related to a joint effort that was carried out to look at work flows and management systems and processes that were being evaluated immediately following the going public transaction.

So what we are now doing with this presentation is we are reviewing it to see what material can be produced. There is forward-looking financial information in that presentation deck and there is information that relates to Hydro One's non-regulated businesses. We are in the process of vetting that document, and we are hoping to file it in this proceeding later today.

MR. QUESNELLE: Thank you. Mr. Rubenstein?

MR. RUBENSTEIN: Yes. Yesterday I did receive the response to Undertaking J2.4, in which all that was provided in that response was a slide -- about a ten-page or -- I'm not exactly sure how many pages -- an 18-page detailed slide deck which summarizes the work Boston Consulting had done with respect to vegetation management.

I then emailed my friends referencing what I believed was the undertaking, which was to provide similar work but not -- that was not specific to vegetation management. In fact, Mr. D'Andrea confirmed that they looked at the whole -- the entire operation that is at line 12 and 13.

I spoke to my friend this morning and he said, I guess there is that report that Mr. Nettleton just spoke about. I don't know if there is similar documentation such as that was filed with respect to the overview of the vegetation management for other aspects of the distribution business or elements that relate to the distribution business, which I think would be of interest to the Board.

I also note that I am up on panel 5 today, and this information is obviously relevant to panel 5. And I'm not asking to delay my cross-examination. I'm ready to go today and I'm -- most of the day.

What I would suggest, if my friends are filing further documentation today, that I be allowed on Thursday or Friday when panel 5 is up to have some additional time, and I will hopefully leave some time today to be able to ask questions, because obviously I won't have a chance to review it, so that's my first thing.

Just also with respect to what is available, I know my -- in fairness I did use the word "final report" when I was asking for the undertaking. I don't know what I don't know. I'm not sure what the format of the material that was provided, and what I was seeking was, there were similar documents where Boston Consulting had come in and

done reviews of various elements of the business. I think that would be of interest to the Board if they've done, you know, an in-depth analysis so -- and so we'd all be able to cross, so I would be looking if there are similar things for the vegetation management that also looks at the distribution business. I don't know if those may or may not exist.

MR. QUESNELLE: Mr. Nettleton?

MR. NETTLETON: I think that the context to the exercise that involved Boston Consulting Group needs to be understood by the Board, and what I've learned in the very short while about that exercise is that it was very much one where the consultants came in and worked alongside senior management and were evaluating the business and the work flows and the management processes together.

In terms of final reports, there were no final reports. The best document that we have that summarizes their work effort is the one that was presented obviously to the board of directors, and we think that that is likely to be the most relevant and salient document that provides a description of what they were able to tell the board of directors about their involvement.

MR. QUESNELLE: And it goes beyond vegetation management?

MR. NETTLETON: Absolutely it does. Yeah, it was -- as I understand it, as Mr. D'Andrea indicated on the transcript, it was a review of the entire operation of Hydro One, both T&D.

So what we're trying to do in this presentation is obviously take out the T. We are trying to take out the non-regulated business and trying to take out the forward-looking financial information, and I think that's the best light.

I would question, Mr. Chairman -- and maybe this is something again where we'll have to have a discussion with Mr. Rubenstein about once Mr. Bowness is on the stand, but I really question the value of going through and trying to find every piece of information that Boston Consulting Group has provided to management at Hydro One with respect to that exercise.

Again, I think the salient point here is that if there is some form of presentation that was given, like the one that we are trying to prepare and provide and file to you, that summarizes the overall effort, we think that that is the best way of articulating what the effort was and what the conclusions were.

I don't think that it makes sense to go through a process of looking at everything and every piece of information that Boston Consulting Group exchanged with the company.

MR. QUESNELLE: No, understood. I don't think that that's what Mr. Rubenstein is asking for.

Why don't we receive the report as a first step, and if there is anything in the report or through the cross-examination that turns up other areas that may be of interest to the Board, I think we'll cross that bridge when

we get to it.

MR. NETTLETON: Thank you.

MR. QUESNELLE: And I guess, Mr. Rubenstein, whatever comes up in the report, depending on when we get it today and you'll have some time to review it, certainly, as long as panel 5 will still be up, you can revisit your cross-examination with them.

MS. GRICE: Mr. Chair?

MR. QUESNELLE: Yes.

MS. GRICE: I have a preliminary matter as well.

MR. QUESNELLE: Yes, Ms. Grice.

MS. GRICE: In panel number 1 AMPCO asked for an undertaking, J1.8, for Hydro One to provide a version of the data to support tables 4 and 5, estimated input to SAIDI and forecasted SAIDI hours, and what these tables are, they summarize the assumptions that Hydro One has used to define its capital plans A, B, C, and B modified, and it shows the estimated impact to SAIDI and SAIFI from those plans, and I had asked in panel 1 if Hydro One could please provide the supporting calculations in advance of panel 5. That is an undertaking that is still outstanding, so I just wanted to check-in today on when that might be filed.

MR. NETTLETON: Ms. Grice, I had understood from my colleagues at Hydro One that that undertaking had been filed, so there may be a misstep here. I will check and see, and perhaps we can consult with each other at the break and I'll find out more about that. But I thought that information was on the record.

MR. GRIFFIN: Okay.

MR. QUESNELLE: Thank you, Mr. Nettleton, Ms. Grice.

Okay, if there is nothing else, perhaps we're ready. Mr. Stephenson?

HYDRO ONE NETWORKS INC. - PANEL 4, WORK PROGRAMS, RESUMED

Ben Grunfeld,

Ken Buckstaff,

Steve Tankersley; Previously Affirmed.

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

I am going to start first with the Navigant First Quartile file report, and I am going to come back to an issue which has been touched on. It is the observation that is made in the report regarding pole demographics as between Hydro One on the one hand and your comparator group on the other.

You indicate in the overview of your -- or the executive summary of your report that the replacement rate is slower than comparison utilities, the pole inventory is the oldest, on average eight years older than the rest, and that the planned life is about ten years older for Hydro One than the comparison group.

Those were part of your findings, correct?

MR. BUCKSTAFF: Yes.

MR. STEPHENSON: First off, we heard yesterday about

some of your findings that didn't have -- statistically, there were some questions of statistical significance about some of your findings.

On this one about pole demographics, is there any issue about statistical significance regarding those observations?

[Witness panel confers]

MR. BUCKSTAFF: We didn't calculate any statistical significance around this set of data, but these are pretty straightforward age characteristics built up over a long time.

MR. STEPHENSON: Okay. Now, just -- I want to focus first on the issue about the planned life of the poles being ten years greater in -- for Hydro One than for the comparisons. And what I'm trying to figure out is whether this is a good news story or whether this is a bad news story.

And so as far as I can understand it, you weren't aware of or able to discern any environmental, or material, or any other basis for this distinction. That is, how is it that Hydro One is able to eek ten more years out of expected life out of poles than anyone else in your comparison group?

That's right, you weren't able to find some magic bullet that Hydro One has that nobody else has discovered.

MR. BUCKSTAFF: I think that's correct. There is nothing obvious that says why their planned life is longer, or the fact that they have a higher age. There is no

underlying reason why that is, other than that's the way they plan it and the way they execute.

MR. STEPHENSON: And there wouldn't be any obvious environmental factors, in the sense of the environmental conditions in Ontario being more benign than elsewhere that would appear to justify that result; is that fair?

MR. BUCKSTAFF: I think that's fair as well, yes.

MR. STEPHENSON: And are you aware of, or did you identify whether this demographic profile has any reliability impacts which are differential than in your comparison group?

MR. BUCKSTAFF: That isn't something that we studied for this project.

MR. STEPHENSON: All right. And are you otherwise aware of the answer to that? I'm not -- I'm not concerned about this particular project, but is that something that you had knowledge of?

MR. BUCKSTAFF: We do other studies where we look at failure rates associated with reliability numbers, meaning causes of SAIDI minutes and things.

MR. STEPHENSON: Yes.

MR. BUCKSTAFF: We don't actually typically look at it as pole failures contributing to that. That shows up as one part of distribution equipment failures. So it wouldn't be something that's isolated to just poles in any of the studies that we do.

MR. STEPHENSON: Right. But what about the issue of demographics and failures? I take it that's something that

you've -- you are aware of and see in your work.

That is, if you have significant population of poles that are older beyond expected service life, for example, that there is a -- there is a nexus between that fact and failure rates.

MR. BUCKSTAFF: Personally, in the data that we've looked at for companies across North America, we haven't seen direct pole failures tied to age.

What we find is that most of the companies make a big effort to recognize and change them out before they age to the point of failure.

MR. STEPHENSON: Right.

MR. BUCKSTAFF: So we don't see data that would suggest that age contributes to it. Intuitively, it seems obvious that it would. But the actual data suggests the companies are taking proactive action before the age destroys the poles.

MR. STEPHENSON: It is manageable and it's managed?

MR. BUCKSTAFF: I suppose that's a way to describe it, yes.

MR. STEPHENSON: What about trends? In terms of demographics, in terms of -- for example, at page 12 of your report, that's where you have a couple of charts about age. This is obviously a point in time analysis on these two charts, correct?

MR. BUCKSTAFF: Yes, at the time we asked the question of the companies.

MR. STEPHENSON: Right. Do you have any data or

intelligence with respect to trends, in the sense that is -- amongst the comparison groups, is there a trend to the age profile getting older, younger or the same? The same with planned life; is there any change on that factor over time?

MR. BUCKSTAFF: In the three-year window we're looking at here, we certainly didn't see any trend in that. As you noted, it is a point in time when we ask what is your planned life, so we just have the one dataset or data point for that for each of the companies.

As far as our broader studies, other studies that we do, the age of those poles doesn't change very much. You think about it, people have thousands of poles. They age one year per year, but they change out a bunch. So any one company is not going to change much over as much as a five- to ten-year window. It will still look pretty similar for several years at a time.

MR. STEPHENSON: And Hydro One is one of the bigger -- its pole inventory is one of the larger ones, fair enough?

MR. BUCKSTAFF: Yes.

MR. STEPHENSON: So that inventory, the size of that inventory would tend to make it more stable in terms of its demographics, fair?

MR. BUCKSTAFF: Yes. It would take a big change to change that by very much in a short window. I mean, you'd have to do a whole lot to change it.

MR. STEPHENSON: Right, but we actually have evidence in this case that their demographics are materially

changing for the worse. I mean, does that come as a surprise to you? I appreciate that's not part of your evidence, but we actually have that evidence, and that the age is creeping up materially even over the course of this application period. Is that -- I mean, is that something that's of surprise to you?

MR. BUCKSTAFF: Well, it is certainly something that we didn't know about. I mean, we hadn't studied that set of data, but it's not -- the fact that it's aging is not shocking. I'd find it hard to believe that it aged more than one year per year, but that's just a fact that it couldn't happen, but in terms of getting a little bit older anytime you don't replace at the same rate you put them in, it will get a little bit older.

MR. STEPHENSON: Okay. One of your recommendations is about refurbishment as a potentially cost-effective means of addressing pole condition. And I just wanted to explore with you the viability of that in a resource-constrained environment.

The evidence in this case is that Hydro One is deferring its rate of pole replacement, and even before the deferral, the average age and average condition of its poles is getting worse over the period of the application, and moreover, that the average -- the number of poles in very poor condition will be increasing over the period of this application.

I'm just asking you to accept all those as facts for the purposes of this question.

MR. BUCKSTAFF: Okay.

MR. STEPHENSON: From a priority perspective, you know, in view of those constraints, why would it make sense for Hydro One to devote resources to a refurbishment project, relative to dedicating those same resources to simply increasing the replacement rate to mitigate the worsening condition?

MR. GRUNFELD: So a pole refurbishment program is not a substitute for the pole replacement program that Hydro One is undertaking. The recommendation that we made in our report was that Hydro One should consider implementing a pole refurbishment program in certain situations where it makes sense.

Pole refurbishment makes sense potentially when a pole fails prematurely or is on the verge of failing prematurely, so for example, if a pole is already 50 or 60 years old, pole refurbishment is generally not an option.

If a pole is 15 or 20 years old and is on the verge of failing or is showing signs of defects that could be remedied through various refurbishment activities, then the cost of that -- of refurbishing that pole could be lower and could yield better total life-cycle costs for that pole than replacing it outright.

And in those situations, we think it's worthwhile for Hydro One to consider and to look more closely at whether pole refurbishment makes sense. And that's what we see in other utilities across North America.

Pole refurbishment, however, is not going to address a

trend in the age of the poles, again because typically refurbishment is targeted at younger poles that are at risk of premature failure.

MR. STEPHENSON: Let me just see if I've got you on that. Thank you for that answer, but let me see if I've got you on that.

So is the point being that this is -- your recommendation isn't about spending incremental dollars. Rather, it is about making operational choices about work you are going to do anyway, if you know what I mean.

So in other words, you've got a pole, and it's, to use your example, 15 or 20 years old, and it looks like it's got some problems, and Hydro One makes a decision that it's in need of replacement and they are going to replace it and spend that money.

And you say, hang on a second, maybe you shouldn't replace it. Maybe you should refurbish it because it's cheaper and you get better bang for your buck. Is that what you are talking about?

MR. GRUNFELD: That's a fair assessment, yes.

MR. STEPHENSON: Okay.

MR. GRUNFELD: And as part of a broader pole management program, that can free up additional funds to then replace additional older poles and improve the total age profile and the total risk profile.

MR. STEPHENSON: Right. But you would agree with me that if this becomes about incremental dollars in the sense that a pole which you would not otherwise be touching, to

use one of your guys' words, you then decide you are going to touch because you are going to refurbishment, and you are talking about incremental spend, then you get into this whole question of trade-offs about which is the higher priority, right?

MR. GRUNFELD: That's correct.

MR. STEPHENSON: Okay. And you don't know the answer to that trade-off -- I mean, it's hard to answer that one in the abstract?

MR. GRUNFELD: That's correct. And we weren't asked to look at that.

MR. STEPHENSON: Okay. Let me move on to Clear Path. Thank you.

The first question is, sir, do you have any ongoing engagement with Hydro One with respect to the implementation of its new vegetation management program that comes out of your study?

MR. TANKERSLEY: Yes, I do, in an advisory role.

MR. STEPHENSON: Okay, and can you assist us: When did Hydro One start to make the transition operationally to the implementation of this new strategy?

MR. TANKERSLEY: They started looking at elements or how this might be applied about the fourth quarter of 2017, with plans to move towards implementation in 2018.

MR. STEPHENSON: All right, well, we're now in June. And so where are they at?

MR. TANKERSLEY: In what regard?

MR. STEPHENSON: Implementation.

MR. TANKERSLEY: They are in implementation at this point, going to a new standard.

MR. STEPHENSON: And implementation, as I would imagine, you know, involves a lot of recalibration of activities out in the field. I mean, it involves other things as well, for sure, but it certainly includes a recalibration of activities in the field; fair?

MR. TANKERSLEY: That is correct.

MR. STEPHENSON: Okay, and that is ongoing now, correct?

MR. TANKERSLEY: It is.

MR. STEPHENSON: Okay. And so I assume that you had, in your head at least, if not somewhere in terms of reporting back and forth with Hydro One, a path -- a progress chart about what you need to get done at what stage in order to achieve timely implementation. You must have something like that, correct?

MR. TANKERSLEY: Well, in order to achieve the recommended three-year cycle, it equates to completing approximately 34,000 kilometres of line in a given year. It's not linear in that the production may be at different levels throughout the year, but that is essentially the bottom line.

Another element is the forecasted number of trees that meet the criteria, and doing a likewise segment of that work at various periods through the year, so looking as both of those elements.

MR. STEPHENSON: I totally understand. I mean, this

is -- you are not doing an equal amount of work every week, every 52 weeks of the year.

My question, however, really is this. I mean, given the non-linear nature of this, and given the fact that you are in an implementation process, presumably you and Hydro One had certain milestones that you had, in terms of where you anticipated being at various points in time this year in order to achieve the implementation that would need to get you where you wanted to be at the end of the first year, correct? You had milestones?

MR. TANKERSLEY: Those milestones have been developed, correct.

MR. STEPHENSON: All right. Have they been achieved?

MR. TANKERSLEY: They are -- not in their entirety, but they are within a level that it can be achieved throughout the year, their end result.

MR. STEPHENSON: Well...

MR. TANKERSLEY: They have demonstrated that they can hit those milestones on a week-to-week basis. Now it needs to be sustained, and there is no reason to believe at this stage that they can't meet that at the end of the year.

MR. STEPHENSON: Let's put it this way -- and it sounds like you are suggesting that they need to do a little bit of catch-up, but you believe it is an achievable amount of catch-up; is that fair?

MR. TANKERSLEY: I believe it's achievable.

MR. STEPHENSON: How far off their milestones are they now, in terms of we're in the middle of June, you know, are

we at point where we are a month off the milestones, two months, three weeks? Where are we at?

MR. TANKERSLEY: I'm not sure where they are as of this point of time. I have not seen the most recent reports.

MR. STEPHENSON: Okay. I wonder if I could get -- we've got one document pulled up on the screen for you. This is exhibit I, tab 29, CME 28, and there's a chart at the bottom of this page which reflects the old versus the new. And I appreciate you may not have been directly involved in the preparation of this chart, but what I want to ask you is -- you will see there are three metrics that they are looking at, the kilometres completed, the trees treated and the total cost, and then they compare old and new for one year and three years.

This is -- you understand that this is what Hydro One is planning on doing by way of implementation of the strategy that you recommended and they accepted?

MR. TANKERSLEY: That is correct.

MR. STEPHENSON: And just seeing how it all sort of works, if I'm comparing the one-year totals just for the purpose of this, at 2018 old and new, as I understand it, basically they're looking at completing almost three times as much in terms of kilometres, correct?

MR. TANKERSLEY: Correct.

MR. STEPHENSON: But they're looking at a fewer number of trees that they are dealing with by some significant amount, right?

MR. TANKERSLEY: Correct.

MR. STEPHENSON: And so I just did a little bit of arithmetic, and I literally divided to get the number of trees per kilometre. It is not very complicated.

And so if I look at the 2018 totals under the old strategy, they are treating 71 -- basically 71 trees per kilometre, whereas under the new strategy, they are treating 21 trees per kilometre.

Does that make sense to you, those numbers?

MR. TANKERSLEY: Yes, it does.

MR. STEPHENSON: And so we're looking at less, less than a third of the trees being treated, correct?

MR. TANKERSLEY: Correct.

MR. STEPHENSON: And that's sort of how you get to the kilometres, right? You are doing less than a third of the trees, and therefore you were able to do triple the distance. That's kind of how this is achievable, right?

MR. TANKERSLEY: Right, focusing on a certain segment of the tree population.

MR. STEPHENSON: Right. Let me ask you this question. So the two-thirds of the trees that they used to be dealing with and they're not going to be dealing with on this strategy, are they trees that effectively never get dealt with, or are they trees that get dealt with only much more infrequently in subsequent cycles?

MR. TANKERSLEY: This does not mean that they will not be dealt with at some time in the future. It is suggesting that those trees that are deemed to be either a current

defect or a potential defect until the next cycle will be dealt with during the current cycle.

Under the old strategy, you were trying to make a feeder or a circuit last for a duration of 8 to 10 years. The cycle was stated at 8 years, which would require you to work far more trees than would be necessary to make that feeder hold for a shorter cycle, and that's where that comes into play.

MR. STEPHENSON: Now, let me just come back to implementation for a minute. In your report, you give a case study. There is -- you make reference to a case study, and I -- what wasn't clear to me, and maybe I just didn't read it closely enough -- I mean, this is a significant change in their philosophy, and not just their philosophy, their actual operations on the ground, correct? This is a pretty significant change?

MR. TANKERSLEY: It is.

MR. STEPHENSON: And, you know, Hydro One is a large organization and they've got a large territory and, you know, it is difficult to turn big ships on a dime.

And so I'm just wondering about your experience regarding the track record of big organizations with big programs making this kind of material shift with this degree of speed.

MR. TANKERSLEY: There is no doubt this is a large shift, a big shift in the way they're approaching work. I've had direct experience in not only vegetation, but other areas in a large organization making a big change.

And I suggest in the report and through my experience that they take that very seriously, and take the steps necessary to achieve that change.

That change started with a considerable amount of on-the-ground communication with the field staff, the people than were actually going to do that, understanding that there was going to be some amount of resistance, particularly in the beginning, but that the measures are in place to help guide that change through the process.

You'll notice in the recommendations in both the first report and the second report, I suggested a very robust quality control program. That is one element of monitoring that change, so that you know what is going on in the field is what you have proscribed to be done through the program, and then being able to use that information to effect change through the organization during that period of time.

One of my biggest -- right from the very beginning, biggest concerns and something that I relayed to Hydro One was the ability to adapt to that change. And I have to say, from my experience, they have done a remarkable job of working through that. They have had support from the very top and all through the organization, and you see that right now, right down to the field staff. While there still may be some skepticism, I don't think it's at a point where you -- it wouldn't be expected. In fact, I think it's at a point that is exceeding what normally would be expected in this case.

MR. STEPHENSON: All right. I may be able to get this

from the next panel, but let me ask you what you know about this. Again, this is in terms of the pace of the implementation, bearing in mind, of course, that it isn't linear, but their target for 2018 is, as you can see, is 34,600 kilometres. Do you know where they're at?

MR. TANKERSLEY: I don't know exactly where they're at, but I believe at this point in time they should be -- based on what I've seen maybe six weeks ago, they should have exceeded the entire amount that they did in the previous year. So I believe they're -- they're exceeding roughly 12,000 kilometres with a gearing up for production latter half of the year.

So this is not going to be a cake walk, there is no doubt about it. This is going to be very much a stretch goal. I think they're doing the right things, they're doing it at the right times, and I have confidence that if they continue, that they will meet those goals.

MR. STEPHENSON: And just from a risk analysis perspective, if this -- if this was going to go awry in some fashion, what are the key sort of potential risk factors that would lead to this going awry and then what are the consequences of it going awry?

MR. TANKERSLEY: Well, if you mean that they don't achieve their stated goal of 34,000 kilometres, I believe that they are still going to be in better shape than their previous model, which was not achieved in an eight-year cycle. In fact, I believe it was averaging about 9.2, in some cases even longer.

There is a significant amount of risk in that area, in my opinion, and you see performance and reliability relative to the vegetation management is less than desired by some margin, and that even if they weren't able to meet this, they would be in a better position than they would otherwise.

MR. STEPHENSON: Isn't there another kind of risk, not about the amount of completion, but rather the quality of completion, in the sense that the stuff that they do accomplish isn't done in a manner which achieves the desired outcome, in the sense that they're not picking the right trees or they aren't -- they aren't trimming them enough or whatever, you know, that -- and such that it doesn't produce the operational and reliability impacts that you would hope to achieve, having done that pass.

MR. TANKERSLEY: Well, if they abandon any quality control associated with this work then that is quite possible. If they are doing the quality control, which they are at this point, and the results suggest that they are, by and large, getting the right trees, then I think they minimize that sort of risk, and just by the fact that they're getting outside of the right-of-way, looking more at the hazard trees, in itself is going to have significant impact on public safety and reliability, and that is occurring relative to the quality-control results that I have seen.

MR. STEPHENSON: Okay, and then just finishing up with this, sir: What should this Board be looking for in order

to give it confidence that this program is succeeding, you know, in the sense of -- or putting it the other way, what red flags should the Board be looking for if it's -- if this program is in trouble and not -- not not being deployed as you had hoped or not achieving the results that you had hoped or whatever.

So at what point in time is it fair for the Board to say, you know, things are okay, they're all looking great, or -- and -- or there is some concern here? Is it after a year? So when is it, and what is it they should be looking for?

MR. TANKERSLEY: You will start to see the results after the first year. In fact, you may start to see some of those results before that. After the first three-year cycle it will become very apparent, and as you start the second cycle, but there are two elements that you might look at. We talked a little bit about quality control. There is another element that I would characterize as quality assurance.

Now, the whole pretext of this is that we are going to -- it is going to be a defect-based system. So we are going to prevent defects. Defects, as a segment of the entire population, are relatively -- should be relatively small, and what we're looking at right now, not so much. There is about 800,000 as we see.

If you were to do a similar but not as exhaustive survey as we did in the last survey, where you were looking at defects at different times since the feeder was

performed and then in aggregate and measure it against the information that we provided on a defect rate, you should see improvement after the first year.

Now, overall I believe the number was 6 defects per kilometre. That's across all feeders, irrespective of when they were last worked.

After the first year I should see a number that is significantly different than that, and those feeders that were done more recently should have a zero or near-zero defect per kilometre basis.

Now, that's showing one thing that you are addressing the defect levels on the system. The second component of that is we -- just yesterday looked at -- is outage investigation. These are disruptions caused by trees. Disruptions caused by trees can either be random, it is a green healthy tree during a storm, or any other event where it falls, or it's related a tree that has a defect, that I believe a defect is more -- more likely to cause a disruption than a non-defect.

So if I were to measure that over time and I looked at my outages, and if they were defect cause or non-defect cause, and actually, we are starting to see that right now, and that those feeders that have the OCP applied have had very few, if any, outages caused by a defect. They have had outages, but those outages have been determined to not be caused by something that would have been under the scope of the work.

Those feeders that have not been worked have a much

higher rate of outages caused by a defect, and I think those two components together, over a period of time, will be able to tell you if your program is effective.

Now, quality assurance point of it is -- needs to come in at some point in the future, perhaps after the first year of the first cycle. It is a little too early for that, but you use the same or very similar processes we did in the survey, and then you can equate post and -- pre and post results from a defect level.

MR. STEPHENSON: And, sir, are you advising Hydro One with respect to the metrics that they should be tracking in order to determine success or failure of this program as it's rolling out?

MR. TANKERSLEY: I have made some suggestions and have reviewed some of that, but not to any major extent.

MR. STEPHENSON: But I take it that some of those metrics would be what you've just talked about, these defects per kilometre and that sort of thing.

MR. TANKERSLEY: I believe that's the plan.

MR. STEPHENSON: Thank you, sir. Those are my questions. Thank you very much.

MR. QUESNELLE: Thank you, Mr. Stephenson.

Mr. Tankersley, you are using the term "defect" throughout. I think I have a sense of what you mean by that. But maybe before we carry on with Ms. Durant, could you just describe all that is encompassed within the umbrella term "defect"?

MR. TANKERSLEY: Sure. A defect as it is generally

characterized is a tree that is growing or contacting the conductor through growth, or trees that have the potential to fail and strike the conductor if they do fail, that are dead, diseased, decadent, defective. It's a segment of the population of trees that you have determined to have -- the most likely to fail.

Now, that said, over time in a effective program, you can alter what you consider to be a defect to be more specific. And what we are talking about today is pretty general. It is a tree that grow into dead, diseased, decadent.

Let's say, for example, that through my outage investigation, my outage history, I determine that a certain species of tree in a certain condition has a high likelihood of failure, even though it is alive and healthy and green and normally would not fit the other determination, such as -- I understand balsams are a problematic tree. I might include balsams in addition to that definition and say those, under this defined condition, would be considered a defect and therefore, I would want to eliminate that defect.

MR. QUESNELLE: Thank you. That's helpful. Thank you. Ms. Durant?

CROSS-EXAMINATION BY MS. DURANT:

MS. DURANT: Good morning. My name is Erin Durant and I am counsel to Canadian Manufacturers & Exporters. I'm going to start with the forestry survey, and some questions for Mr. Tankersley.

Mr. Tankersley, you were aware that your report was going to be used by Hydro One both to improve things going forward, but also for use at the Ontario Energy Board. Is that right?

MR. TANKERSLEY: I was not aware that it would be used at the Ontario Energy Board.

MS. DURANT: Okay. This was a surprise to you, that you would have to be here?

MR. TANKERSLEY: I learned that later, yes.

MS. DURANT: Well, thank you for coming. And you became aware, and I can get that sense from your report and some comments in here, that historically the OEB had some concerns about Hydro One's historical approach to maintenance; is that right?

MR. TANKERSLEY: The OEB did?

MS. DURANT: The OEB.

MR. TANKERSLEY: Yes.

MS. DURANT: And what I take from your report is that historically, Hydro One has had a fairly inefficient method of removing trees, is that correct, on their right of way?

MR. TANKERSLEY: Not as characterized. I think the program objectives and approach to vegetation management were not optimal.

MS. DURANT: Okay. And, you know, the sense that I get in the big picture is that Hydro One was going along the right of way removing every tree, even trees that would have no impact on the actual system. It was basically a clear cut, is that right?

MR. TANKERSLEY: Essentially, within the right of way boundaries, but not necessarily outside of them.

MS. DURANT: Okay. If it was in the right-of-way boundary, they'd removed trees that, for example, may not have been tall enough, or the species may never get tall enough to actually become an impact on the system; is that right?

MR. TANKERSLEY: Potentially, yes.

MS. DURANT: So part of your work -- and you worked with a company called ArborMetrics, is that right?

MR. TANKERSLEY: Correct.

MS. DURANT: And was it your company or ArborMetrics that did the work on the ground, in terms of going out and taking a look at the current right of ways?

MR. TANKERSLEY: ArborMetrics.

MS. DURANT: And part of their work was they wanted to get a sense of what the right of ways looked like currently, and get a sense of also what trees were on the right of way; is that right?

MR. TANKERSLEY: It was far more encompassing than just that, yes.

MS. DURANT: And the reason it was encompassing is you wanted to have a clear picture of what it actually looked like on the ground, is that right?

MR. TANKERSLEY: That's correct.

MS. DURANT: And you took those factors, in terms of the current status of the right of ways, into consideration when making your recommendations in your report, is that

right?

MR. TANKERSLEY: Correct.

MS. DURANT: And the main change with what Hydro One was doing historically and what you're recommending is you're recommending a more focused approach in terms of hazards and, as we just heard a moment ago, by being more selective in what's being cleared, you are able to go further and get more line in a less amount of time. Is that right, at a very high level?

MR. TANKERSLEY: At a high level. It is intended to be selective to eliminate or reduce the number of defects, not only that are currently existing, but those that will for the duration of the cycle.

MS. DURANT: And by making this change, Hydro One's able to get down to a three-year cycle, which you think is optimal. Is that right?

MR. TANKERSLEY: At this point, I do.

MS. DURANT: Okay. And prior to your involvement and your recommendations, it's my understanding that Hydro One was operating on an eight-year cycle. Is that right?

MR. TANKERSLEY: A stated eight-year cycle they were not achieving.

MS. DURANT: Okay. And if we could just go to page 6 of your report which is fill at Exhibit Q-11, attachment 2, and I believe it's actually page 7 of the PDF document.

That's the one. Under heading "Defect rate over time", there is a chart here and my understanding of the chart is the pink header shows -- sorry, you are on the

wrong page on the screen. There it is.

Your "since last worked" six to eight years and there is a nine-plus years. Those years since "last worked", that was basically where Hydro One was before you got involved, right, in terms of their cycle length?

MR. TANKERSLEY: Well, the survey was stratified. Each circuit or each feeder, we looked at when that was last treated according to their records.

MS. DURANT: Okay. So this doesn't show -- this shows actually when the last segment had been cleared and what the cycle was when you looked at it, right?

MS. DURANT: Correct.

MS. DURANT: And it makes sense that as you wait longer to clear the right of way, there is going to be more defect, there is going to be more problems, right?

MR. TANKERSLEY: Yes.

MS. DURANT: And that's what your chart shows here, that the longer you wait, the more problems you are going to have, right?

MR. TANKERSLEY: Correct.

MS. DURANT: If we could go to the next page, this is -- at the very top of the page, where it says six to eight years after the work, what you are finding was that the overall defect rate increased 36 percent from the previous interval, which was, I think, a cycle of three to five years since last being cleared.

So there is a 35 percent increase from that standing, and more than double from the zero- to two-year interval,

and that was just based on what you observed from the study?

MR. TANKERSLEY: Survey results.

MS. DURANT: Survey results, okay. If we can jump to page 15 of the report, this is a section dealing with cost modelling. So you looked at basically two things, the big picture in the report. One was can we make improvements in terms of reliability, and two what's this going to cost. Is that right?

MR. TANKERSLEY: Correct.

MS. DURANT: So this is in the section dealing with cost, and you make certain projections regarding cost here.

I'm interested in the section towards the bottom which says the projections are estimates based on the available data, and are influenced by a number of factors.

So the factors listed here, these are factors that may change your numbers, your projections. Is that right?

MR. TANKERSLEY: Correct.

MS. DURANT: And I want to focus in on some of the negative influences. And you just told my friend that you are involved with Hydro One going forward, in terms of giving them advice throughout this transition, is that right?

MR. TANKERSLEY: Correct.

MS. DURANT: So you are giving them some advice to mitigate against some of these negative influences, I imagine; is that right?

MR. TANKERSLEY: Correct.

MS. DURANT: So under negative influences, number 1 is: "Maintaining scope is critical to avoid cost escalation." And that is something that you are helping them with?

MR. TANKERSLEY: At this point, not directly. I am reviewing some of the result, but this is largely coming out of the quality control program.

MS. DURANT: Okay. And in terms of what you've seen regarding scope, are you content that they are on the right track?

MR. TANKERSLEY: They are on the right track.

MS. DURANT: And in terms of feeder prioritization and scheduling, you write: "Worst first could result in unequal distribution of work."

What do you men by worst first?

MR. TANKERSLEY: If you took all the nine-year-plus feeders and eight-year-plus feeder over a three-year period, let's say those were all going to be included in the first year of the first cycle, then you may not be able to complete one-third of the kilometres in the first year under that cost, but subsequent years of the first cycle might become easier if you did a worst first type of scenario.

MS. DURANT: So it's your recommendation that they shouldn't just do worst first and that would be an inefficient approach; is that right?

MR. TANKERSLEY: This isn't really a recommendation --

MS. DURANT: Okay.

MR. TANKERSLEY: -- this is an observation --

MS. DURANT: Yeah.

MR. TANKERSLEY: -- so if you were to take that approach then you would have to look at that element, so the approach that was ultimately taken was looking at it from a sub-out type of a basis. I can't recall the terminology that was used, but it was looking at it in a broader sense.

MS. DURANT: So the method that was ultimately decided on is they weren't going to just target the worst first, it was a more holistic approach, and they were going to get to everything over the course of a three-year cycle; is that right?

MR. TANKERSLEY: They took a number of factors into consideration, and I was not involved in the direct prioritization of the feeders.

MS. DURANT: Okay, and what can you tell me about -- so you didn't agree with me that they're going to get to all the backlog over the first three years, but how are they going to approach that, or do you know?

MR. TANKERSLEY: I believe they are --

MS. DURANT: Okay.

MR. TANKERSLEY: -- if they stay on track and they are able to increase their production levels or plan throughout this year that they will be able to achieve a three-year cycle.

MS. DURANT: And they are not going to do a worst first approach to get there?

MR. TANKERSLEY: They are going to do a modified version of that, and the specific prioritization, feeder prioritization, that would be a question for Hydro --

MS. DURANT: Okay. And in terms of the costing, the approach that they selected, does that change the costing in your report, or do you think that the approach they've selected is still within your projections?

MR. TANKERSLEY: I believe that they can achieve it within the projections that I have seen. Again, it's -- there are some challenges there, but...

MS. DURANT: Okay. And just one last question for you, sir, before we move on. If we go to page 4 of the PDF, which is page 3 of the report. And I'm looking at the heading "forecast workload and cost". I'll just read from the report. It says:

> "It is estimated that 2.1 million trees will need work over the first three-year cycle to achieve base level defect control..."

Let me stop there. When you say "base level defect control", you need to clear that many trees in three years to basically get the system caught up, right? Is that what you mean by "base level"?

MR. TANKERSLEY: You are doing two things with that. So you have an existing defect load over the system which is roughly 800,000 trees that are existing. Then there are the remaining portion of that would be to avoid having defects on that same feeder for the duration of that cycle.

MS. DURANT: Um-hmm.

MR. TANKERSLEY: Presumably after you get through the first cycle, the second cycle, you are not dealing with existing defects, you are dealing with preventing -- prevention of future defects.

MS. DURANT: That's all included in your scope of work and your costing, right, that model?

MR. TANKERSLEY: Correct.

MS. DURANT: Okay. And ultimately at the end of that paragraph, in terms of costing:

> "This regimen will significantly reduce cost per kilometres from 11,000 per kilometre to an estimated 3,000 per kilometre after the first cycle."

Is that right?

MR. TANKERSLEY: We're suggesting that that will occur throughout the first cycle.

MS. DURANT: Okay, so it's not like you have to wait 'til the third year to get the $3,000 -- get down to $3,000 per kilometre. Gradually throughout the first three-year cycle the costs are going to go down?

MR. TANKERSLEY: That is the intent, yes.

MS. DURANT: And then after the first three-year cycle, once you are at a base level, you should expect to be around the 3,000 per kilometre mark going forward after three years.

MR. TANKERSLEY: Yes.

MS. DURANT: So you don't have to wait for after three years to start saving costs?

MR. TANKERSLEY: Correct.

MS. DURANT: Okay. I have some questions for Navigant, not as many. And I want to start -- similar question. You were aware when you were retained to do this report that it was to be used at the OEB as a benchmarking study; that's right?

MR. GRUNFELD: Yes.

MS. DURANT: And the OEB actually requested a benchmarking study to be done; is that right?

MR. GRUNFELD: Yes, that's correct.

MS. DURANT: And we heard yesterday some concerns that you had with regards to the survey size and the number of comparator utilities. Despite those concerns you are still confident that you are able to draw some conclusions from this report, right?

MR. GRUNFELD: That's correct.

MS. DURANT: Okay. And the sample size is large enough to support the conclusions in the report?

MR. GRUNFELD: We believe that the sample size, along with our experience, are able to support the conclusions in the report, yes.

MS. DURANT: Okay, and if you go to page 14 of the report. I just want to clarify a few things. We spoke yesterday about the replacement cost per pole, and I'm under heading 3.5, "pole replacement cost", and across the comparison group the average cost to replace a pole was stated in the report as being 7,105. For Hydro One the cost was 8,266, or 16 percent higher than the mean. And

that's what it says in the report. And yesterday you told us that there was some concerns just about that finding because of the sample size; is that right? You drew our attention to this yesterday, and you gave us some figures in your introductory statement in terms of some concerns you had about that finding; is that right?

MR. GRUNFELD: Yes, that's correct, we added some clarity around the statistical significance of that conclusion.

MS. DURANT: Right, and the one question I had about this is you pointed out utility number 39, and if you flip to the next page you will see it, and you mentioned utility 39 had a very small number that was reported back in terms of their cost to replace the pole; that's right?

MR. GRUNFELD: That's correct.

MS. DURANT: Did you follow up with utility number 39 in terms of why their cost was so low?

MR. GRUNFELD: We did not.

MS. DURANT: You just accepted their number and put it in your report?

MR. GRUNFELD: That's correct.

MS. DURANT: Okay, so to the extent that this number, you know, threw off your results, you never bothered to follow up to see what the actual number is?

MR. BUCKSTAFF: To be fair, we did actually contact them to ask. We didn't manage to connect with them and get an answer from them.

MS. DURANT: Okay, okay, and just in terms of the

number of companies and the number of comparators, when I count the numbers here under the pole replacement cost, I get 11 companies responding, including Hydro One; is that right?

MR. GRUNFELD: That's correct.

MS. DURANT: And that's the small sample size you are concerned about, is there being only 11?

MR. GRUNFELD: It is the small sample size combined with the variability in the responses.

MS. DURANT: Okay.

MR. GRUNFELD: If it was a sample size of 11 and they were all within, you know, plus/minus 2 percent of each other, then we'd be able to draw more significant statistical conclusions, but it is the combination of those two factors.

MS. DURANT: Okay. If we can go to page 7 of the report, under the heading "cost comparisons", I just noted in figure 7 and figure 8 we also have 11 companies responding to these metrics, and these are metrics where Hydro One comes in close to average, right?

MR. GRUNFELD: That's correct.

MS. DURANT: And if you go to figure 8 in particular, I note that company number 52 here, they seem to have much higher costs per pole than the other companies; is that right?

MR. GRUNFELD: That's correct.

MS. DURANT: And in this metric Hydro One would be benefiting from the one company that's significantly higher

than average; is that right? I see Hydro One is at 29, fairly close. They are pretty much above median, so Hydro One being close to average would be, you know, being brought up by this company who has a very high cost per pole; is that right? The average would be higher --

MR. GRUNFELD: The higher cost for that individual company would increase the average of the sample; that's correct.

MS. DURANT: Okay. All right, those are my questions, thank you.

MR. QUESNELLE: Thank you, Ms. Durant.

Mr. Segel-Brown.

CROSS-EXAMINATION BY MR. SEGEL-BROWN:

MR. SEGEL-BROWN: Hello, my name is Ben Segel-Brown speaking for the Vulnerable Energy Consumers' Coalition. I have a compendium, but the witnesses do not have copies because Hydro One is going to object to it, but we'll get to that when I get to it.

So regarding a refurbishment, you recommend that Hydro One consider modifying its program to include a rigorous pole refurbishment program; is that correct?

MR. GRUNFELD: That's correct.

MR. SEGEL-BROWN: So I'm trying to figure out what the expected savings would be associated with the refurbishment program.

You've given us the mean cost to refurbish a pole as $947, is that correct?

MR. GRUNFELD: That's correct, for this sample.

MR. SEGEL-BROWN: And the average cost to replace a pole is 7,105?

MR. GRUNFELD: That's correct, for the entire sample.

MR. SEGEL-BROWN: So how would we go about determining the portion of poles due for replacement that are suitable for refurbishment?

MR. GRUNFELD: So as I mentioned to the earlier question, pole refurbishment tends to be only viable when a pole is young and is showing signs of defect or potential failure.

A pole refurbishment program can potentially increase the life of a pole anywhere from 20 to 40 years. So if you have a 20-year-old pole that has some early signs of, you know, decay, rot, other failure mechanisms, then it's possible that refurbishment of that pole could extend the life for better value than, say, replacing that pole. But it really depends on the demographics of the poles that are being replaced.

MR. SEGEL-BROWN: And to be more specific, you state that where refurbishment can extend the life of a pole by over 20 years, the economic benefit of refurbishment tends to be clear.

MR. GRUNFELD: That's correct. Again, it gets to the one-fifth, one-seventh of the cost.

MR. SEGEL-BROWN: So to determine the number of Hydro One's poles due for replacement which are suitable for refurbishment, we would have to know the number of Hydro One's poles due for replacement which are less than --

which have a remaining life of 20 years or greater, and those would be -- that would be the subset of poles that are suitable for refurbishment?

MR. GRUNFELD: That would be one of the considerations. The nature of the defect would be another consideration.

MR. SEGEL-BROWN: So how would I go about figuring out, of those poles which have a remaining asset of life of 20 years which are due to be replaced, are suitable for refurbishment?

MR. BUCKSTAFF: That's a question that you answer by doing your assessments of the poles. When you go out and inspect them, those are choices you can make when you go out to do the inspections.

They're not something that you can do from an office here.

MR. SEGEL-BROWN: It's not something that we could infer from the classification of pole defects, like woodpecker damage, or rot?

MR. BUCKSTAFF: You might be able to get to that. But again, each pole is going to be a specific case. You can look at it and say what's its age, what's its circumstance, what's possibilities for this one.

MR. SEGEL-BROWN: So to give some context for this, we're being asked to approve a capital expenditure to replace a large number of poles. So what I want to understand is the extent to which the proposed refurbishment program may be able to substitute for those

additional capital expenditures.

So you -- and you, from your data, you have the number of poles that were refurbished by each of these utilities as a percentage of the total poles that were refurbished or replaced.

So are you able to provide an indication of the portion which is suitable for refurbishment?

MR. GRUNFELD: We weren't asked to look at the specifics of the pole replacement and refurbishment program, and we weren't asked to design an alternative. So no.

MR. SEGEL-BROWN: I'm not sure what the correct procedure would be. I'm not sure I can ask for an undertaking of an expert witness that would involve additional work for them, so maybe I would ask that of Hydro One.

MR. QUESNELLE: Yes, I would think when the asset panel is up, you can pose the question as to -- I think what you may be getting at, Mr. Segel-Brown, is the -- and I'll ask the question of the experts here.

Your recommendation that Hydro One entertain a refurbishment program, was that made primarily due to the fact that other entities that you surveyed have refurbishment programs, and Hydro One does not appear to have one? Their program is if there is a defective pole, you replace it?

MR. GRUNFELD: That's generally correct, yes.

MR. QUESNELLE: So directionally, you are suggesting

consider a refurbishment program because it has the potential for savings, but that's not based on any assessment of the population in the circumstance?

MR. GRUNFELD: That's correct.

MR. QUESNELLE: So I would pursue it further with the asset panel, Mr. Segel-Brown.

MR. SEGEL-BROWN: Could you explain to me the difference between refurbishment, reinforcement and maintenance, which may overlap to some extent.

MR. BUCKSTAFF: Refurbishment and reinforcement are pretty similar. I mean, there's two or three treatments you can do. You can put some form of a sleeve around the pole. You can use chemicals to pump into the pole to fill voids in it. Those, dependent on terminology in individual utilities, would be considered reinforcement or form of treatment. So those are choices you might have.

MR. SEGEL-BROWN: So in conducting this report, did you review the practices of other utilities with regard to this kind of maintenance activity?

MR. BUCKSTAFF: We didn't review the practices. We asked about them in the sense of do you or don't you have a refurbishment program and if so, what does it include. And we gave them a couple of choices of what it might include.

But in terms of further exploration of that with them, we didn't do that.

MR. SEGEL-BROWN: So you were provided with some detail from them regarding what their refurbishment program entails. Is that included anywhere in your report?

MR. SEGEL-BROWN: I don't believe the details of that are actually there in the report. The report just summarizes for Hydro One what we recommended for them. But I don't believe we have in the report the details of exactly which companies said they'd do chemical treatment versus sleeves, or whatever.

MR. SEGEL-BROWN: But it's safe to say there were practices in place at Hydro One -- at other utilities that Hydro One does not do?

MR. BUCKSTAFF: Did not at that time, yes.

MR. SEGEL-BROWN: Yesterday you stated that while Hydro One's pole replacement costs are higher than average, that difference is not of statistical significance -- statistically significant.

MR. GRUNFELD: That's correct.

MR. SEGEL-BROWN: Is statistical significance discussed anywhere in this report?

MR. GRUNFELD: It is not, no.

MR. SEGEL-BROWN: Now, the reason why the difference was not statistically significant depends on two factors; first, the difference, and second, the standard deviation in utility costs, correct?

MR. GRUNFELD: There's three factors. There's the difference, the standard deviation and the sample size.

MR. SEGEL-BROWN: Now, in calculation statistical significance, I'm assuming that you treated each utility as one observation?

MR. GRUNFELD: That's correct.

MR. SEGEL-BROWN: So I'm not convinced that that's the correct statistical test. Are you familiar with the T-test used to compare the difference in means between two groups?

MR. GRUNFELD: That's test that we deployed.

MR. SEGEL-BROWN: So to apply that test, wouldn't you have to take into account the standard deviation in pole replacement costs within each utility?

MR. GRUNFELD: We looked at a three-year average pole replacement cost.

MR. SEGEL-BROWN: So you used the standard deviation over the three years rather than the standard deviation between projects?

MR. GRUNFELD: Between individual years, that's correct. We looked at the average of the three years for each individual utility, and then compared those three-year averages.

MR. SEGEL-BROWN: So to illustrate this with a hypothetical, suppose you had two utilities, each replaced a thousand poles, their average costs are a thousand apart. The standard deviation of each is, you know, $100.

Wouldn't we be able to conclude that the costs associated with those two groups are significantly different from each other? Wouldn't we want to be looking at the standard deviation and the cost per project rather than the standard deviation in year-over-year average costs?

MR. GRUNFELD: I'm not sure I understand the question. We averaged the three-year -- each -- these aren't

individual projects. We didn't collect the cost data for each individual pole and what the cost to replace each individual pole was and then added it up. We collected data for the total pole replacement program cost and the number of poles that were replaced within that program in a given year, and then we calculate a cost per pole replaced. We did that for three calendar years, so we asked for data for all of 2012, the cost of the entire pole replacement program, the total number of poles replaced for 2012, 2013, and 2014, and then we looked at the average value over the three-year period, and then calculated the average for each across the sample of utilities. And then we compared the Hydro One value to that and determined the statistical significance of the difference.

MR. SEGEL-BROWN: Thank you for the clarification regarding how your methodology was applied. I think that will still have to go to argument.

So what threshold of significance were you looking for? What threshold would you need in order to conclude that Hydro One was significantly different?

MR. GRUNFELD: We were looking for the P value to be less than .1 or less than .05. It was significantly higher than either of those thresholds.

MR. SEGEL-BROWN: So my concern with that is if we assume that costs are normally distributed, then Hydro One would have to be in the top or bottom 2.5 percent of utilities in order to meet that .5 -- or that significant threshold; is that correct?

MR. GRUNFELD: No, what we're -- what the test is determining is whether or not the value for Hydro One can be statistically confirmed as being different from the sample mean that we calculated.

So if you have a population of data, if you had the average -- if you had the pole replacement cost for every single utility in a population, then you can just look at the value for Hydro One and determine whether it's higher or lower than the mean. But because you're working with a sample, you can't necessarily state that the sample mean is the population mean.

And so what the statistical tests demonstrate based on the variability of the values within the sample, and based on the value that you're testing, is whether or not that value you're testing is statistically different from the sample mean, and so each value is assumed to be -- if you were to draw another ten utilities from the population and that value -- the mean of that -- of that sample might be different than the mean of the sample that we calculated. And based on the variability and the number of companies within that sample, we can't say statistically that Hydro One's value is different from the mean of the population.

MR. SEGEL-BROWN: The point I'm getting at is that the scientific threshold used to determine whether Hydro One is different is looking at whether there is a 5 percent chance that we would have observed this from the same population by chance alone, so that means that your -- the value for Hydro One would have to fall in either the top 2.5 percent

or the bottom 2.5 percent of the population in order for it to be considered statistically significant, according to your test?

MR. GRUNFELD: I don't believe that's a correct interpretation.

MR. SEGEL-BROWN: That's for argument too. Are you able to provide the utility-level data?

MR. GRUNFELD: In response to one of the interrogatories we did provide the utility-level data behind those charts. I will look up the number. It's School Energy Coalition interrogatory number 26.

MR. SEGEL-BROWN: Thank you. But to get back to the key point, your results suggest that as your best guess Hydro One's costs are 16 percent higher than the mean?

MR. NETTLETON: Objection, Mr. Chairman. I don't think the witnesses have said anything about a best guess. So I'd ask my friend to rephrase the question.

MR. SEGEL-BROWN: Your results indicate that Hydro One's costs are 16 percent above the mean?

MR. GRUNFELD: As I stated in my opening remarks, I believe there are some challenges with cherry-picking individual results from the report. We've indicated that if you exclude the outlier, ID number 39, Hydro One's pole replacement costs are 6 percent higher than the sample mean, and I've indicated that in either of those cases we can't say with statistical confidence that Hydro One's costs are higher than the mean.

MR. SEGEL-BROWN: But isn't that in your own way

cherry-picking the results by deciding to exclude the exceptionally low result but not the corresponding exceptionally high result?

And -- like, the point I was getting at with saying your best guess is I'm saying that there is a margin of statistical uncertainty around your number, but, you know, if we were going to place a bet, your best guess would be that Hydro One's costs are going to be 16 percent above the population mean. That's what your results mean.

MR. GRUNFELD: I tend not to be abetting man.

MR. SEGEL-BROWN: Like, the whole purpose of this report was to compare Hydro One's costs to a benchmark, to the population. Are you saying that you are not able to tell me what you think the difference between Hydro One's cost and the general population is as a percentage of the --

MR. GRUNFELD: That's correct.

MR. SEGEL-BROWN: So any sources of error, such as variations in climate, would tend to lead to greater variance and therefore lower statistical significance; correct?

MR. GRUNFELD: To the extent that you have more variability in the results, it is harder to draw conclusions around statistical significance; that's correct. I think there are lots of factors that contribute to variance in pole replacement costs.

MR. SEGEL-BROWN: So despite -- you expressed it in your report that you think that there are a lot of factors

which influence the cost of replacing poles, but you did not -- you decided -- in the end you decided not to control for any of those confounding variables because in your data you could not show that there was a difference. Is that summarizing the approach that you took correctly?

[Witness panel confers]

MR. GRUNFELD: You're correct in stating that we did not control for any factors in our study.

MR. BUCKSTAFF: It's actually noted in our report -- I am just trying to find it -- that we did test for those various factors, distance travelled and soil type and several of those variables, and were not able to demonstrate that they had a statistically significant impact, so we did not control for them.

MR. SEGEL-BROWN: So that was my understanding, but it kind of goes to whether this is an appropriate data set, whether the data is of sufficient quality and a sufficient sample size in order to draw conclusions about whether there are significant differences, because if we can't identify a significant difference associated with these major variables you've identified like the percentage of poles installed off a road, percentage of poles installed in soft soil, travel time, average age, if we can't show any statistically differences associated with major factors like those, why would we expect to be able to find a significant difference between utilities?

MR. GRUNFELD: I think we are -- we recognize that there are limitations imposed, based on the amount of data

that we were able to collect and the size of the sample that we were able to build.

I think that predisposing a judgment isn't appropriate. I think that there's -- if all of the values had been more -- had been more tightly correlated or more closely -- more closer together, pardon me, then, you know, that would have resulted in a different outcome. But the reality is that there is, based on the data that we collected, there is a wide range of outcomes, which makes drawing strong statistical inferences difficult.

MR. SEGEL-BROWN: So in your analysis of substation costs, you mentioned in discussing it yesterday -- I'm not sure I saw it in your report, it might be there as well -- that Hydro One's projects tended to involve fewer components with lower capacity, and you saw that as a reason that would tend to reduce costs.

Did you analyze whether Hydro One's costs were statistically significantly higher when controlling for those -- that fact that you identified of capacity?

MR. BUCKSTAFF: No. I mean, the size of the samples on these, we didn't do a lot of statistical testing on them. It's pretty clear they're not going to be detailed enough to be able to draw those kinds of conclusions.

MR. SEGEL-BROWN: You note at page 10 of your report that Hydro One is the only company that performs more than 95 percent of inspections with in-house crews, as compared to nearly 100 percent outsourced in other companies. Is that correct?

MR. BUCKSTAFF: You are back to poles?

MR. SEGEL-BROWN: Yes, back to poles, sorry.

MR. BUCKSTAFF: Yes.

MR. SEGEL-BROWN: Did you assess whether there were potential cost savings associated with contracting out part or all of pole inspections?

MR. BUCKSTAFF: We didn't. We just noted the difference in the staffing approaches.

MR. SEGEL-BROWN: Okay. You also recommend considering the use of dedicated pole replacement crews, is that correct?

MR. BUCKSTAFF: Yes.

MR. SEGEL-BROWN: And presumably you recommended that because you believe such crews could be cost-effective?

MR. BUCKSTAFF: Yes.

MR. SEGEL-BROWN: Do you have a sense of what the cost savings associated with such specialized crews might be?

MR. BUCKSTAFF: No, we didn't calculate anything like that. It is one of those -- it is evident that there is opportunity there, but we didn't try to quantify it.

MR. SEGEL-BROWN: The next question I believe you answered this morning, where you said that you did not find any difference in reliability between utilities depending on pole age. Is that correct?

MR. BUCKSTAFF: We don't have data to show that.

MR. GRUNFELD: And that wasn't part of the study.

MR. SEGEL-BROWN: So at page 4 of your report, you indicate that you collected data on emergency pole

replacement volumes, costs and hours. So that would presumably act as an indicator of the pole failures?

MR. BUCKSTAFF: It does. The fact is that in pole replacement programs, the grand majority are done as a programmatic thing, not as an emergency thing.

MR. SEGEL-BROWN: Right, which is what we'd like to see.

MR. BUCKSTAFF: Like planned.

MR. SEGEL-BROWN: Right. But your results don't support -- they don't support an inference about what the appropriate asset life is for these wooden poles. It doesn't suggest -- well, let's not be a compound question.

You can't draw any conclusions about reliability based on the age of the pole is what you are saying, the average age of the poles.

MR. BUCKSTAFF: We have not.

MR. SEGEL-BROWN: Okay. So you were also asked to look as trends over time. Did you draw any conclusions regarding trends and pole replacement costs over time?

MR. TANKERSLEY: For Hydro One or for the group? What's the...

MR. SEGEL-BROWN: Well, presumably you'd start with Hydro One, and then look if there's a trend in the overall group that might explain it.

MR. BUCKSTAFF: And we did, for the three years, provide the data and you can see it in the charts as far as what's happened with them.

There is -- in a three-year span, we are not going to

have a statistical validity again of here's how much it has grown. If you -- we didn't do it for this study, but we have looked at it over a the span of a number of years. The costs of these are creeping up just as the other costs of distribution are creeping up.

They're not -- there is no noticeable difference in the way people do poles versus the way they do other things that causes them to -- the costs to rise any faster or slower on pole replacements.

MR. SEGEL-BROWN: So it was basically the conclusion that appears in this chart, that the costs have increased slightly from 2012 to 2014 with a down in 2013?

MR. BUCKSTAFF: Yes.

MR. SEGEL-BROWN: So for the next question I am going to want to refer to my compendium, to which Hydro One has an objection.

MR. NETTLETON: Yes, I do, Mr. Chairman.

MR. QUESNELLE: Okay, thank you. Is your microphone on, Mr. Nettleton?

MR. NETTLETON: I believe it is. Sir, I received this compendium 30 minutes before the start -- not even 30 minutes, immediately before the start of the session this morning.

The witnesses have certainly not seen the material that is contained in this compendium.

From my search of the material that is referenced here, there is a variety of documents that underscore the excerpts that have been provided.

And it strikes me -- my biggest concern is that all of this is facts that could have been provided in advance, and could have been tested with the witnesses through interrogatories.

This is not new information and it's been taken out of context to a large extent. For example, the tab 2 Manitoba Hydro 1.7 distribution asset economic valuation comes from a report that is over a hundred pages long, a report that's dated 2012.

The reference to B.C. Hydro comes from a response for which the interrogatory question was not provided. The interrogatory question was: For each of the past ten years and for each of wet and dry locations, what was the average cost per pole and total cost of replacing poles in the distribution system?" And that was filed in a BCUC in a B.C. Hydro and Power Authority revenue requirements application in 2004.

As for the other material, the Hydro-Québec reference, it appears to have come from an Internet posting, where a customer of Hydro-Québec by the name of Ryan from Shawville on May 1, 2016, asked on social media the question: "Who pays the cost of installing new hydro poles?"

And the reference is by Hydro-Québec:
"As on all social media, we post questions exactly as we receive them. They are then translated."

And finally, sir, with respect to the Saskatchewan Power reference, it, too, seems to be taken out of context,

and by that I mean there is only one passage in this compendium that speaks to cost. But what isn't included is the passage below the reference of and the heading of why we're doing it. Below that passage on their website, on the Saskatchewan Power website, there is reference to the fact that in 2017, the work crews are working in the areas of Davidson, Regina, Strasberg, and Moosonee to deal with the carpenter ant infestation and mechanical damage.

Now, sir, the concern that I have with all of that is, again, this material was not brought to these witnesses' attention.

There has been an extraordinarily long examination process. There has been a technical conference. There have been interrogatory opportunities. And to be blind-sided, as my witnesses would be, by having this information suddenly appear, and to be taken out of context in which all of this material seems to have first landed, and to be put to the witnesses and say, what do you think, quite frankly, sir, I think that's unfair, and it's -- it should not be considered an appropriate means of conducting cross-examination before this Board.

So I'm objecting to this compendium, and I don't think it's reasonable or proper for the witnesses to be providing evidence for you to rely on in this manner.

Those are my submissions.

MR. QUESNELLE: Mr. Segel-Brown?

MR. SEGEL-BROWN: So the compendium is intended to establish that there's publicly available information

regarding the pole replacement costs, and that that publicly available data is substantially inconsistent with the figures which appear in the benchmarking study. I indicated to counsel for Hydro One that I was happy to accept any responses to this material taken as an undertaking, given that the witnesses have not had time to review it, and that I would not -- and I'm not seeking to use this evidence to establish that these are the pole replacement costs in these other jurisdictions or that these would be an appropriate benchmark, but rather to use them to test and seek elaboration regarding the meaning and reliability of the benchmarking results.

MR. QUESNELLE: Mr. Segel-Brown, would you not be able to do that without the use of these aids that, as you've just described, do not represent -- or you don't present them as being representative of the actual pole costs in these jurisdictions and that they may be different? And if that's not what you are establishing, then what assistance do you need from them?

MR. SEGEL-BROWN: It's difficult to seek explanation for the witnesses as to why the costs which they're reporting for these Hydro utilities are several times what those utilities have publicly reported without being able to state that that has been publicly reported.

MR. QUESNELLE: I'm catching a contradiction in what you're saying then, Mr. Segel-Brown. You just suggested that you wouldn't be presenting these as being representative of the costs in these jurisdictions, and yet

you want to draw the witness to a comparison of what they have found to these costs. I'm not catching your -- the use of these...

MR. SEGEL-BROWN: Right, so there is a difference between using the evidence to challenge the expert opinion which has been given and using it to independently establish that this is an appropriate benchmark to use or something, so what I'm saying is that I'm not using this to establish a different benchmark which would be used to assess reasonableness; I am only using it to attack the meaning and credibility of the Navigant report.

MR. QUESNELLE: So if the experts asked you questions about the validity of these from a comparison point of view, and Hydro One's counsel, Mr. Nettleton, has just done a little research by the sounds of it -- and I don't know if you agree with his observations or not -- that there's -- it is a challenge to put these to the witnesses and suggest that -- suggest, even from an observation, is that what you intend to, from an observation, why is it that your findings are higher than what I have found here? Is that the crux of the question?

MR. SEGEL-BROWN: Yes. I mean, you also have to weigh the entire purpose of the report was a unit benchmarking study intended to establish the cost for pole replacement, and it appears that the experts did not consider publicly available data regarding that, and the figures which are publicly available are significantly different and merit explanation.

MR. QUESNELLE: Well, I think the explanations that would be required for this panel to rely on them is what their source and whether or not they are comparable, and so I don't know -- if you are putting this forward, the challenge for us would be to -- how much weight do we put on these, because these haven't been analyzed, I suppose.

To the extent that you are seemingly going back and forth, Mr. Segel-Brown, as to what reliance you are placing on them and what you are presenting them as, so are you presenting these as costs that could be -- should be put to these expert witnesses as to why they didn't go to the airwaves and the Internet to determine where other sources of data would be that are available? Is that...

MR. SEGEL-BROWN: Yes, pretty much.

MR. QUESNELLE: Okay, we're going to take our break now. We'll return at 11:35 and we'll rule on this matter.

--- Recess taken at 11:21 a.m.

--- On resuming at 11:43 a.m.

MR. QUESNELLE: The Panel has considered the compendium that VECC was proposing to have accepted and brought on the record. The Panel accepts Mr. Nettleton's objection and rationale for the objection.

If there was evidence that was intended to challenge the study and the report that Hydro One has filed, it should have been brought in much earlier and it could have been tested.

I think on its face there are sufficient questions that Mr. Nettleton put forward as to what kind of reliance

we could put on this. The panel also noted that one of the references is SaskTel, which is a telephone company, not a power utility, which I think would drive some different outcomes.

So I think, Mr. Segel-Brown, you've questioned and the panel on -- the witness panel on the merits of their study and the rationale and the assumptions. I think if you have anything further to that, certainly go ahead. But the referenced material in your proposed compendium is not something we'll entertain putting before the witnesses.

MR. SEGEL-BROWN: Okay, I'll continue without the compendium.

MR. QUESNELLE: Thank you.

MR. SEGEL-BROWN: In completing your study, did you review publicly available data regarding pole replacement costs?

MR. GRUNFELD: No, we did not.

MR. SEGEL-BROWN: And it's your view that there is an evident error in the collected data, at least in the case of utility 39?

MR. BUCKSTAFF: In that case, for company number 39, yes.

MR. SEGEL-BROWN: And I believe you said earlier that you did not attempt to verify the data provided by the utilities.

MR. BUCKSTAFF: We contacted them; we did not connect with them.

MR. SEGEL-BROWN: Did you attempt to verify the data

provided by other utilities?

MR. BUCKSTAFF: There were a couple of out outliers we contacted, but not all of them systematically, no.

MR. SEGEL-BROWN: Now, reviewing your report, is there anywhere where pole replacement costs are defined, where you explain how you operationalize that definition, like what is included in the pole replacement cost and what is not?

MR. BUCKSTAFF: The questionnaire that we sent out to gather the data shows exactly what the components are that are included.

MR. SEGEL-BROWN: And that's annexed to the report?

MR. BUCKSTAFF: No, we gave it back to somebody as part of an interrogatory. It's SEC number 25, and it's the answer to part B, where they asked to please provide a copy of the questionnaire and we did that.

MR. SEGEL-BROWN: Thank you. Earlier you mentioned that you had already provided the data underlying the report in response to an interrogatory from SEC, and you mentioned 27.

But that only provided the data underlying the charts; it did not provide the micro level data.

MR. GRUNFELD: Yes, that's correct. It was in response to SEC 26 was where that data was provided.

MR. SEGEL-BROWN: So there is no way for us to determine which utility a figure relates to for the purposes of trying to understand why -- which utilities are the best comparators, but why there are differences between

utilities.

MR. BUCKSTAFF: That's correct. We actually gather the data under confidentiality agreements, so we can't share who it is.

MR. SEGEL-BROWN: Okay. Did you conduct literature review in the context of preparing this report?

MR. GRUNFELD: No.

MR. BUCKSTAFF: No.

MR. SEGEL-BROWN: So you wouldn't be aware of any studies that had previously been done regarding the replacement costs as surveyed across North American utilities? You've already answered the question. You did not do a literature review, did you?

MR. BUCKSTAFF: Correct.

MR. SEGEL-BROWN: Did you do a comparison of the mean cost for unit substation refurbishment? I believe you stated earlier did you that you didn't do a significance test, but did you do a comparison of the mean cost?

MR. GRUNFELD: Is there a specific figure that you are referencing?

MR. SEGEL-BROWN: For example, figure 23, 22.

MR. GRUNFELD: No, I don't believe we did.

MR. SEGEL-BROWN: Wouldn't a comparison of the mean costs -- well, properly controlling for certain variables be a key part of a unit cost benchmarking study?

MR. GRUNFELD: As we indicated in the report, I think there are some concerns about the size of the sample for the substation, the substation component.

MR. SEGEL-BROWN: I mean, that cuts both ways. It both makes it difficult to establish whether Hydro One's costs are reasonable, but also whether or not they're unreasonable.

Basically you're saying that based on the data you collected, you can't draw a conclusion about whether their costs are reasonable.

MR. GRUNFELD: We drew a conclusion that the costs are within the range of costs we have observed for the sample.

MR. SEGEL-BROWN: But in the case of figure 22, that's not even the case because Hydro One has the highest cost. So that particular data point would not be...

MR. GRUNFELD: So again, there's two ways to normalize -- there's really ways to normalize costs for substation refurbishments: the value of the equipment that's being refurbished, the size of the -- the transformation capacity, the MVA and the number of transformers, and we presented two of those. And you can see the results are different in terms of Hydro One's performance when you look at those two different metrics.

MR. SEGEL-BROWN: Okay, that's all my questions. Thank you.

MR. QUESNELLE: Thank you, Mr. Segel-Brown. Ms. Grice?

CROSS-EXAMINATION BY MS. GRICE:

MS. GRICE: Good morning. I'm Shelly Grice representing the association of Major Power Consumers in Ontario.

My first set of questions are for Navigant and First Quartile. If we could please turn to page 2 of the Report...

MR. GRUNFELD: Roman numeral 2 or page 2?

MS. GRICE: Page 2. So figure 1 is showing an overview of the benchmarking approach and under quantitative analysis, the second bullet off to the left, talks about validation, and there has been some discussion about that already this morning.

I just wanted to ask for the validation of Hydro One's data. Was that something that you did?

MR. BUCKSTAFF: Well, yes, in the sense that we took the data that they gave us and then asked them several questions about what's included and what's not, and did it match up with the guidelines we gave them for data to be provided to us.

MS. GRICE: Okay, thank you. If we could please turn to page 4? So the figures on page 4 identify the data that was collected from Hydro One and the comparison utilities, and figure 2 is for pole replacement, and for figure 3 it's for substation refurbishment.

I just wanted to get a perspective from Navigant and First Quartile with respect to the overall quality of the data collected for Hydro One.

Did you -- I guess I'll ask: What was your overall perspective or impression of the quality of the data? And I'm thinking specifically around accuracy, completeness and consistency.

MR. BUCKSTAFF: Well, in the report, one of the things we recommend is some improvements to the data collection capability, on the substation side in particular, for Hydro One.

So the reason for that is there was difficulty in getting some of the data that we were after in the substations arena.

In terms of the accuracy, I think we're pretty comfortable that it is accurate and eventually became relatively complete. But to begin with, they had difficulty.

MS. GRICE: Okay, thank you. And then if we could turn to page 26 of the report.

And under the section there, 4.4, "performance measurement", you identify a subject area for tracking. And it says underneath that "age and usage history data for existing equipment", and then you identify the Hydro One practice, which is "limited tracking and available data", and then the leading practice, being "complete data, including installation dates, maintenance activities, and other investment".

Can you just explain to me a little bit what the gap is between what Hydro One is doing and what the leading practice is?

MR. BUCKSTAFF: Well, it's exactly what led to my immediately previous statement. We had difficulty getting some of the data because it's not been tracked for long periods, and that doesn't make Hydro One unique, meaning

there's a lot of companies that can't tell us the age of their equipment beyond, say, 30 years.

Anything 30 years and older, they just don't have the records for as far as when things were installed or who the manufacturers were and some of that.

More recently, people have done much better, and Hydro One is better as well, but a complete data set that you can analyze in lots of different ways is the ideal leading practice, and there is a few companies that have that, but not all of them.

MS. GRICE: Okay. And in terms of equipment, can you just identify -- excuse me, sorry -- identify for me the specific equipment types that you are referring to in this area that requires more tracking?

MR. BUCKSTAFF: The range of equipment that we asked around in the substations is breakers and the bus work, the relays and control equipment, that kind of -- basically all the major components in the stations.

MS. GRICE: Okay, thank you. And then just with respect to the pacing of pole replacement and substation refurbishments and the dollars involved, you did not make a specific recommendation on the replacement rate or the investment levels for these two activities; is that correct?

MR. GRUNFELD: That's correct.

MS. GRICE: And then I just have one last question, and this is on page 4 of the report. Just on the bottom of page 4, it begins the discussion about the comparison group

selection.

I just want to confirm that you haven't noted any underlying concerns about the sample size in your report in this section, correct?

MR. BUCKSTAFF: I guess we didn't describe it as a concern around it. We did note on page 5 that not all the utilities we approached agreed to participate, and clearly we would prefer more data in any study we do like this.

MS. GRICE: Okay, the rest of my questions are for Clear Path. If we could please turn to page 21 of the report. I'm sorry, I misspoke. It is page 22. So just at the top of the page there, under data collection, you provide the data that was provided by Hydro One, and I want to ask you the same question I asked Navigant First Quartile: Do you have an overall perspective of the quality of the data that you received with respect to accuracy, completeness, and consistency? Is there anything that you wish to note?

MR. TANKERSLEY: There were a couple of items in general. They had the information that we needed.

When we stratified the information to determine our -- the segments of line to be reviewed, we did it based on the factors that are listed here, which included the date last worked. And there were instances where, when we got out in the field -- and for example, it might say that it was last worked eight years ago, and there was evidence that there was work that was more recent, which may have been due to remedial work or other things that were done, so we had

process in place to deal with that.

When we ran across those kind of discrepancies from what we saw in the field versus what the data that we had, then we would -- we had a process to exclude that segment and then substitute it with another so that we could take that into account. That was probably the biggest issue that we had.

MS. GRICE: And how great was the frequency of that issue?

MR. TANKERSLEY: Out of the thousand, I would say it would be less than 5 percent, would be my estimate.

MS. GRICE: Okay, can we turn to page 24, please? Sorry, it's page 24 of the report. My understanding is Appendix C is the data that your team went out in the field and obtained; is that correct?

MR. TANKERSLEY: It was part of the survey, correct.

MS. GRICE: Okay. So under "tree population" you show there the population of trees on the right-of-way and off the right-of-way, and it totals 13.26 million, approximately.

MR. TANKERSLEY: Correct.

MS. GRICE: So could we please just turn up a page of the evidence. It is B1, tab 1, schedule 1, DSP section 2.3, page 39. If you could just scroll down the page. Under "rights-of-way", this is the section of the evidence that describes Hydro One's assets, and if you just look at the first sentence -- or the second sentence there, it says:

"Hydro One's rights-of-ways are adjacent to approximately 7 million trees."

And there are other references in the evidence related to 7- to 8 million trees, and I just wondered if you are able to account for the difference between 7 million trees and then the 13.26 million that you counted? Was there -- is there some reason that you are aware of to explain that?

MR. TANKERSLEY: The information we provided was based on extrapolation from a statistically significant sampling, so we're confident that the numbers that we came up with are relatively close at 13.2 million.

There was -- this information was not available prior to the survey, so there were estimates over time that were based on other factors. One of those would be simply that they had been working about 800,000 trees a year on an eight-year cycle, or nine-year cycle is where they were at, which would equate to approximately 7 million trees. That's my best explanation, but that was -- those estimates had been used for a number of years, I saw those in other reports as well, that were not based on a survey such as we performed.

MS. GRICE: So would you conclude that your tree population count is the correct population?

MR. TANKERSLEY: I'm confident in the numbers that we provided through the survey.

MS. GRICE: Okay. Okay. Thank you.

Could we please turn to page 4 of the Clear Path report. So the fourth bullet down, under

"recommendations", it says one of your recommendations is to:

> "Finalize and fully implement an outage investigation process to develop analytics for system awareness and continuous improvement would."

And I just want to confirm that you made that recommendation because it's addressing a gap in what you saw in how Hydro One was tracking outages? Is that where this came from?

MR. TANKERSLEY: Well, it -- they did not have a formal outage investigation process. But as a best practice through the industry, to fully understand the effectiveness of your vegetation management program, service reliability is a key element of that. And in order to understand the effectiveness of your program or the work that you're doing, understanding the cause of the outages is very important, in my opinion. And therefore, it was included as a recommendation.

MS. GRICE: Okay, thank you. And then if we turn to page 11, please, my understanding from reading your report is that Hydro One has now started a formal outage investigation process. The reference to is that is under 4.3, that it was recently started with 262 records in the database; is that correct?

MR. TANKERSLEY: That's correct.

MS. GRICE: Can you tell me when that was started?

MR. TANKERSLEY: I believe it was started at about

this time last year.

MS. GRICE: Okay, thank you. And then if we turn the page to page 13 -- no, sorry, page 12 -- at the top of the page there you've got table 5, and that shows outage causes and it is a breakdown of the 262 records that you referred to on the page earlier. Is that correct?

MR. TANKERSLEY: Correct.

MS. GRICE: And in terms of the outage causes, did you provide those to Hydro One, or did Hydro One come up with these?

MR. TANKERSLEY: There was a collaboration to determine those.

MS. GRICE: Okay. And then in terms of reliability -- a reliability metric, is there a reliability metric industry best practice that you would recommend for the type of vegetation management strategy that you've provided on the three-year cycle? Is there something that stands out as a really good vegetation -- a really good reliability metric?

You mentioned defects per kilometre, but that really doesn't get at reliability. Is there something that you would recommend?

MR. TANKERSLEY: SAIFI is a predominant metric that's used in the industry for vegetation, as well as outages per distance, which would be kilometres or miles as a whole.

There are others that can also be used. In my opinion, SAIFI is a good one. SAIDI is an indicator, but because there are other factors that are introduced, it may

not be the best one for vegetation alone. But SAIFI would influence SAIDI, as would outages per kilometre, and those are very good high-level metrics to use, performance metrics.

MS. GRICE: Okay. Just in terms of major event days and the contribution that trees have to the percentage of outages that occur during a major event day, is that something that you think should be tracked as well?

MR. TANKERSLEY: I suggest looking at both measures with and without major event days, in that they're both influenced by tree-related outages. But to get an entire picture of your effectiveness, I would caution against only looking at excluding major events. Including major events, I think, really tells a story and it's more effective your vegetation management. Often you can have a bigger influence on that than you could on excluding.

MS. GRICE: Okay, thank you. Then just in terms of a unit cost metric, is there an industry best practice unit cost metric that you would recommend for Hydro One's vegetation management strategy?

MR. TANKERSLEY: There are a lot of unit cost metrics to be used, and it depends where you are at in the maturity of your program. Ultimately, I believe that the best metric for unit cost is the cost per kilometre or mile for managing your system to get certain results.

And when I say that, you can have a unit cost to work a tree; you can even take it down to a lower level of different types of trees. That is not necessarily a best

indicator for performance; it is an indicator. Also the cost of working a kilometre or a mile is an indicator, and it's something that's important, but maybe not the best one.

For me, it would be take your total system distance and your total cost on an annual basis, and that will determine a cost per -- in this place, a cost per kilometre.

But it's very important to note that sometimes in benchmarking, some of the best performance in the industry as far as cost per kilometre or mile, they also have worst-in-class performance. So those two definitely have to come together in that you're looking at cost performance. It just may indicate that a program is underfunded and not getting the results.

So using those two in combination, I think, are best practice. But it's kind of an evolution to get to that point, and I would say in the case of Hydro One, the conclusion of the first year cycle is going to tell you a lot more and then as you proceed toward the second and subsequent cycles.

MS. GRICE: Okay, that's very helpful. Thank you. I just have one last area to ask questions on and this is page 3 of the report.

Under 1.3, where it says "Reliability results", the first bullet says:

> "Off right of way tree and branch failures cause approximately 90 percent of all outages."

Where did this data come from?

MR. TANKERSLEY: That was from Hydro One's -- the data that they collected during the event. So this is not an outage investigation per se; it is the initial report from a trouble-man or other person that is out there reporting this information.

So this would be refined over time with actual outage investigations, too.

MS. GRICE: Okay. Can we then turn to page 14 of the report?

Just in the table there, were you -- you are just making some preliminary unit cost projections and you've got kilometres there for zone A, B, C, D and an annual of 34,282.

Given that 90 percent of all outages are off right of way trees, are all those kilometres then off right of way for the first year?

MR. TANKERSLEY: I'm not sure I understand the question.

MS. GRICE: I was just trying to align -- I was just trying to understand if there is an alignment between the strategy, the three-year strategy, and focusing on off right of way trees, given that they cause 90 percent of all outages, if there is any --

MR. TANKERSLEY: The kilometres that are listed are linear and then the right of way, typically on a distribution line is -- I've got to get my conversion to metric -- five meters on either side of centre line. I

believe that's correct. So that would constitute the right of way and then anything beyond that would be off right of way.

But it's still -- in the case of zone A, it's 10,383 kilometres of line. And then the outages that are occurring within that 10-meter right of way represent about six and a half percent of the outages and the remaining 90 percent are outside of that -- which, to a large degree, makes sense in that distance off the right of way is much greater than the distance within the right of way.

MS. GRICE: So there is no strategy that -- so when you get the kilometres, you are doing both off right of way and on right of way?

MR. TANKERSLEY: Oh, absolutely, yes.

MS. GRICE: Okay. That's what I wanted to understand. Thank you very much. Those are my questions.

MR. QUESNELLE: Thank you, Ms. Grice. Mr. Sidlofsky?

Cross-Examination by Mr. Sidlofsky:

MR. SIDLOFSKY: Thank you, sir. Staff, I have a compendium. I believe the panel has copies up on the dais. I'm going to mark that as Exhibit K 6.1.

EXHIBIT NO. K6.1: BOARD STAFF CROSS-EXAMINATION COMPENDIUM FOR HONI PANEL 4.

MR. SIDLOFSKY: And, now, good afternoon, panel. My name is James Sidlofsky. I'm a counsel with Board Staff. And I'm going to start with Navigant, and we'll start with poles and move on to stations, and then I will move on to vegetation management and my questions.

Could I take you to page 2 of the compendium, please. And this is a page that we've seen, I suppose, a number of times before. This sets out your recommended actions with respect to both pole replacement and substation refurbishment.

I'm going to begin with recommendation 1 under "pole replacement", that's considering modifying the pole replacement program to include more complete pole inspections -- for example, sound, bore, and excavation -- and a longer, approximately ten-year inspection cycle.

And under that recommendation I'm wondering if you could tell the Board what your anticipated outcomes and benefits of that recommendation are. And what do you think the costs would be to implement that recommendation?

MR. GRUNFELD: So we didn't analyze the costs associated with implementing that recommendation, so I can't provide you with any insight into that.

In terms of the expected outcomes and benefits, generally speaking, again, we did not look specifically at applying that to Hydro One's program, but generally speaking, the idea would be: Can you amass better data around the poles, make better decisions around pole replacement, by using more invasive testing, recognizing, though, that invasive testing costs more to implement, and so to manage that you have to extend the cycle.

And so it's a trade-off between quality of data and cost of the inspection program, and is there a way to find a balance. Again, we didn't look at the specific outcome

of what would be the implication if they did that, but in general that's the -- those are the two trade-offs that you are making.

MR. SIDLOFSKY: So you didn't do that analysis. Is that something that your client would typically do; you would simply give them the recommendations and they would have to go away and consider their costs and benefits, and --

MR. GRUNFELD: That's correct.

MR. SIDLOFSKY: So you weren't asked to do that by Hydro One?

MR. GRUNFELD: We were not asked to do that.

MR. SIDLOFSKY: In general terms, though, would implementing that recommendation lead to an increase or a decrease in inspection costs and pole replacement costs; can you speak in general terms about that?

MR. BUCKSTAFF: The expectation is it would lead to a slight decrease, but not a major. It won't change the nature of the cost of the total pole program; it will be minor.

MR. SIDLOFSKY: And, sorry, maybe I should have separated those, but would that be an increase in inspection costs because you are being more invasive and a decrease in replacement costs, or --

MR. BUCKSTAFF: Individual inspections will be more expensive. Individual ones. By doing them less frequently you can counter-balance that.

So in the net, the inspection program, the inspection

part of the pole program is likely to be slightly more expensive, but not very much. And then you will have noticeably better information to make your decisions on what poles to do things about.

MR. SIDLOFSKY: I'm not sure that you'll be able to answer this question, given what you've just said, but I'm going to ask it anyway. Do you have a sense of the anticipated performance reliability benefits if Hydro One were to implement recommendation 1?

MR. BUCKSTAFF: Improvements meaning impact on SAIFI or SAIDI associated with pole failures?

MR. SIDLOFSKY: Yes.

MR. BUCKSTAFF: That we didn't try to quantify at all.

MR. SIDLOFSKY: And do you have any sense of whether upgrading visual inspections to those more complete inspections of, you know, sound, bore, excavation type inspections, do you expect that that would affect the number of poles identified as needing replacement?

MR. BUCKSTAFF: It is likely to affect the number needing replacement, and it also gives you a window into, maybe we could refurbish some, so it helps on that, which at the time was not an option at Hydro One, but which they're, you know, likely to be considering for future.

MR. SIDLOFSKY: So it is possible by being more proactive in the inspections you could reduce costs later by refurbishing instead of replacing?

MR. BUCKSTAFF: Yes.

MR. SIDLOFSKY: And are you able to say whether or how

Hydro One made use of this information in its current application?

MR. BUCKSTAFF: Not able to say, no.

MR. SIDLOFSKY: Okay.

MR. NETTLETON: Mr. Sidlofsky, Ms. Garzouzi will be appearing on the next panel, and I'm sure she will be quite happy to talk to you about what their plans are with respect to refurbishment and replacement and this line of questioning.

MR. SIDLOFSKY: Thanks, MR. Nettleton. I expect that I'd be asking panel 5 about that as well.

Page 3 of the compendium, please. At page 3 there's a copy of Hydro One's response to Board Staff Interrogatory No.126, and in that response Hydro One stated that:

> "The strategy currently being evaluated is to alternate detailed pole testing with visual inspections."

Does that proposed strategy satisfy recommendation number 1 from Navigant in your view?

MR. BUCKSTAFF: It's a fair response to it. One of the things noted in our recommendation was in order to change to a longer cycle you'd have to get approval from this Board to make that change, and this is a way to move in that direction without having to change the rules here within the inspection requirements, in terms of timing of inspections and so on.

MR. SIDLOFSKY: So you see this as a bit of a compromise then, or how is it --

MR. BUCKSTAFF: I think it's a fair way to move forward. And again, we recommended, consider this approach, look into it, and see what you can do. If this is their response, that's a reasonable consideration of moving forward. We haven't looked at this in any depth to understand what their long-term plans are around that.

MR. SIDLOFSKY: Okay, back to page 2 of the compendium, just because it happens to be where the recommendations are. Under recommendation number 2 you recommended that Hydro One expand its existing centralized program management and pole selection approach to cover 90 to 95 percent of the replacement or refurbishment work on poles in a given year.

Just for comparison, can you tell us what the current percentage is?

MR. BUCKSTAFF: Not precisely, no. It is somewhere north of 50 percent, but I don't know exactly.

MR. SIDLOFSKY: Okay. I expect Ms. Garzouzi will be able to help with that, Mr. Nettleton?

MR. NETTLETON: I think it will be either Ms. Garzouzi or Mr. Bowness on work execution.

MR. SIDLOFSKY: Okay. Sticking with Navigant's views, in your view would centralizing a larger proportion of total pole replacement decisions help Hydro One optimize its pole replacement program?

MR. BUCKSTAFF: Yes, that's why you would want to do it. It's -- if you do things in a decentralized way you optimize each local area, but it may be that division

number 1 needs 10 percent of their poles replaced this year and division number 2 doesn't, really, but if you give everybody the same kind of long-term, do what you can in your division, you'll end up with 5 percent and 5 percent, and for the system as a whole that's not optimal, so centralizing the planning allows you to then move resources around, move choices around within your system to optimize the whole system.

MR. SIDLOFSKY: Now, you're speaking in general terms here, not from specific experience with Hydro One, this approach; is that right, or...

MR. BUCKSTAFF: Yes, I mean, we see this approach as the best way to do it, and it's a way that's been enabled over the last ten years by tracking systems and ability to understand what you have in your system. 30 years ago, people couldn't really do this. Today they can, so it's the better way to go.

MR. SIDLOFSKY: So that more centralized approach might be a way of optimizing the priority of pole replacements; is that right?

MR. BUCKSTAFF: Replacements and refurbishments, yes.

MR. SIDLOFSKY: At similar costs to the current costs?

MR. BUCKSTAFF: Yeah, by -- by centralizing the planning you aren't going to change the cost of executing the pole replacements. You might be able to get a little bit of benefit by scheduling, grouping them together in nearby areas. But mostly that's already done when you do it regionally.

But what you will get is better ability to prevent future failures, which is really what your pole replacement program is about. You are trying to replace them before they fail, and you will be able to better optimize that.

MR. SIDLOFSKY: Are you aware of whether pole evaluation and replacement policies and practices are standardized through Hydro One territory?

MR. BUCKSTAFF: Conceptually, they are. Any time you have different regional groups making decision, there are slight variations, so...

MR. SIDLOFSKY: Would it also be possible, though, that without a centralized approach, you could have poles that are evaluated in one area as needing replacement, but those could be in better condition than poles in another area that are not in need of replacement?

MR. BUCKSTAFF: That's possible, but that's less likely than if, say, I'm in division A and I say we're on a long-term plan and we're going to replace X number of poles, I will choose the poles that are most likely to need replacement. And my colleague over here in his next division might choose his most necessary group of poles, and his might be more important than mine.

We're not using any different criteria for selection; we're just simply saying I'm taking my 2 percent and he's taking his 2 percent, and mine happen to be worse off than his. So if you then centralize that, then you take away from the two of us the choice of I'm taking 2 percent of all my poles, regardless of exactly how bad they are.

Does that make sense? Does that help you?

MR. SIDLOFSKY: I think that's helpful, thank you.

MR. BUCKSTAFF: Okay.

MR. SIDLOFSKY: How that actually shakes out, I realize I will have to speak to different witnesses about that. But I appreciate the comment, though.

Could I take you to page 6 of the compendium? There are two figures on that page and they are both marked as figure 8. But we've seen these figures before earlier today.

Now, in those two figure 8s, the inclusion of the outlier values for company 52 skews the cost average so that Hydro One's cost performance relative to its non outlier of peers is de-emphasized.

You had that discussion with Ms. Durant, I believe. Do you recall that?

MR. BUCKSTAFF: Yes.

MR. GRUNFELD: And you mentioned to Ms. Durant that the average unit costs shown in the figures would be significantly lower if company 52 were excluded from the analysis.

MR. GRUNFELD: I don't believe we used the word significant, but it certainly would be lower if you excluded the outlier.

MR. SIDLOFSKY: Didn't want to put words in your mouth; sorry about that.

But would that lead to the conclusion that Hydro One's cost per pole would worsen relative to its peers? Would it

then render Hydro One more -- on the more expensive side if you were to take out that outlier?

MR. GRUNFELD: In that metric, yes.

MR. SIDLOFSKY: Okay. And my question to follow up on that is: Would the exclusion of the outlier values from your analysis materially change any of your findings or recommendations?

MR. BUCKSTAFF: I don't think they'd change our conclusions nor our recommendations. The basic conclusion is Hydro One is near the mid range, and there's things to do to improve. And those are reflected in the recommendations.

MR. SIDLOFSKY: Okay. The next page, page 7 of the compendium, please. On that page, you state that the cost of replacing a pole is substantially higher than the cost of refurbishing a pole, and you've said that replacement is approximately seven times more expensive where refurbishment is an option.

How did you determine that pole replacement is seven times costlier?

MR. GRUNFELD: That was based on the averages of the sample data that we collected.

MR. SIDLOFSKY: On the next page of the compendium, page 8, in its response to OEB Staff Interrogatory 122, Hydro One states that they're investigating structural refurbishment and chemical refurbishment.

Do you have any information on how much more expensive pole replacement would be compared to those two

refurbishment options? And is it -- just to go on with my question, is it roughly seven times either of those approaches?

MR. BUCKSTAFF: Roughly speaking, yes. They are slightly different in their own cost, but you kind of have a choice when the time comes to use one or the other of those refurbishment approaches.

MR. SIDLOFSKY: Okay. So if we are sticking with the seven times value, could we just go back to page 7 of the compendium, please?

Now, you say a few other things in addition to mentioning that pole replacement is about seven times the cost of refurbishment.

You suggest that it wouldn't make sense to refurbish a 50-year old pole when the useful life is planned for 60 years.

You then go on to say, though, that refurbishment can extend the life of a pole by 20 to 40 years, and you say that in any scenario where a refurbishment can extend the life by over 20 years, then the economic benefit of refurbishment is clear.

MR. BUCKSTAFF: Yes.

MR. SIDLOFSKY: That's all accurate, right? It accurately depicts what you've said on that page?

MR. BUCKSTAFF: Yes.

MR. SIDLOFSKY: To my mind, that suggests that you could extend the life of a 50-year old that has 60-year life by another half of its useful life at one seventh of

the cost of replacing it. So on that basis, why wouldn't it be reasonable to refurbish it instead of replace it?

MR. BUCKSTAFF: Well, the probability of refurbishment of a 50-year old pole turning that into a 90-year life on that pole is low.

It's not going to be the same for the pole that's 20 years old versus one that's 50 years old, in terms of just the age and wear on the thing over time.

MR. SIDLOFSKY: Well, maybe if we don't go to the far end of that at 40 years, but could you turn a 50-year old pole into a 70-year old pole?

MR. BUCKSTAFF: Possibly. It's -- that's not something we've investigated in great depth.

MR. SIDLOFSKY: If you can do that, that would still represent a savings compared to replacement, wouldn't it?

MR. BUCKSTAFF: Without having gone through the analysis on that, I don't know. The starting point for us was simply take a look at some of the younger ones and work from there. You may choose later on to extend that, but right now we're starting from a policy that says we change them out or don't, not any other options.

MR. SIDLOFSKY: So is your point then any steps that you take toward refurbishment represents an improvement?

MR. BUCKSTAFF: Investigation of it, certainly, to see is there an objection here and will it be better in this specific circumstance for Hydro One.

MR. SIDLOFSKY: You don't have any reasons that Hydro One has given you about why it doesn't use pole

refurbishment, do you?

MR. BUCKSTAFF: No.

MR. SIDLOFSKY: So when it was explained to you, it was simply we replace the pole or we don't?

MR. BUCKSTAFF: Yes, that's the practice in place.

MR. SIDLOFSKY: Okay. You mentioned earlier that you utilities typically utilize pole rehabilitation or refurbishment.

MR. BUCKSTAFF: The majority of them do, yes.

MR. SIDLOFSKY: Do you have any information on how many of Hydro One's peers from your study do not use pole refurbishment?

MR. BUCKSTAFF: I believe the answer is 13 of the 17 that we got answers for that question do refurbishment, but we'll confirm that here in just a second.

There it is. It's on page 13 of our report, 13 of the 17 in the study.

MR. SIDLOFSKY: Thank you. Moving on to stations, I'll just take you back quickly to page 2 of the compendium. And specifically under recommendation number 1 with respect to substation refurbishment, you recommend that Hydro One implement a formal data governance process for equipment, performance, and maintenance data, and that this information be incorporated into the asset condition scoring and project planning process.

Can you provide some information on the cost and performance consequences of Hydro One's lack of a formal data governance process for equipment, performance, and

maintenance data?

MR. BUCKSTAFF: Specific cost, no. I mean, it's one of those things where better information will enable you to do better, but quantifying that by how much, I don't know.

MR. SIDLOFSKY: Performance consequences, are you aware of -- do you have any information on those?

MR. BUCKSTAFF: Again, specific quantitative answers, no. You are looking to have better information to make your choices, make your decisions on when you're going to do various maintenance or replacement activities.

MR. SIDLOFSKY: So is that really the benefit of incorporating that information into the asset condition scoring and project planning process, the idea that you can make better decisions; is that the point of this?

MR. GRUNFELD: Yes, that's correct.

MR. SIDLOFSKY: As opposed to being able to predict specific costs that will be avoided or specific performance improvements?

MR. GRUNFELD: That's correct. I mean, the performance improvements stem from making better decisions.

MR. SIDLOFSKY: So just to turn that around a bit, does that suggest that the lack of a formal governance process or formal data governance process leads to suboptimal project planning decisions?

MR. GRUNFELD: Not necessarily. I think there's -- there are ways to accommodate for suboptimal data, you know, validating on-site prior to starting -- or prior to going -- engaging in a project or what-have-you. So

there's ways to correct for data gaps.

MR. SIDLOFSKY: Okay. Under recommendation number 2:

> "Navigant recommends that Hydro One enhance its cost and work completion reporting for individual projects and implement a formal change control process."

Does the lack of a formal change control process contribute to -- potentially contribute to project scope creep or rework of elements of projects?

MR. BUCKSTAFF: It can, and in other projects that we've done, other places, we've been able to demonstrate that kind of thing, that having better controls and having better procedures around your management of projects, you can do better. Here the fact that they aren't very formalized suggests there's an opportunity.

To your question, we'll follow here in just a second about, so how much, we don't have that answer, but in terms of the opportunity, better data, better information, better reporting enables you to make better choices and manage things better along the way.

MR. SIDLOFSKY: Without getting into specific numbers, because I appreciate you don't have them, in general terms, could the lack of a formal change control process result in a higher-than-necessary cost for past refurbishment projects?

MR. BUCKSTAFF: It could contribute, yes. And recognize the situation that Hydro One's in is the same situation that every other utility has been in over time.

Over the last 20 years, everybody has gotten better capabilities for capturing, managing, and using information. It is not that the past approaches were bad or inferior, they are just simply better now, and so moving as quickly as possible to the better capabilities is what you want to do.

MR. SIDLOFSKY: Well, according to your recommendation, Hydro One doesn't seem to have a formal change control process. Otherwise you wouldn't be making the recommendation, right?

MR. BUCKSTAFF: That's right.

MR. SIDLOFSKY: How does that compare to other utilities in your sample group?

MR. BUCKSTAFF: Some of them have very developed, very fully developed, formalized processes, others do not. And there is a range for that.

MR. SIDLOFSKY: Do you have a number for that?

MR. BUCKSTAFF: No, not -- I mean, I can't say it's 13 out of 17 or something like that. No.

MR. SIDLOFSKY: Okay. In response to Staff interrogatory 126 -- that would be on compendium page 3. Thank you -- Hydro One indicated that it had enhanced its cost estimating by releasing detailed cost estimates rather than basing -- basing their estimates off of unit costs, and my question is whether, in your view, a detailed scope is required in order to provide a quality estimate.

MR. BUCKSTAFF: You're asking about stations here?

MR. SIDLOFSKY: Yes.

MR. BUCKSTAFF: Okay. Yes, you would want to have a detailed scope, particularly where you are doing a full station rebuild or a major refurbishment. Individual components maybe not, but for the full station rebuild you'd want to have a complete scope so you could estimate what it will take to do it.

MR. SIDLOFSKY: Okay, so I'm going to take you to page 10 of the compendium. And that's an extract from the transcript from the -- sorry, from the technical conference in this proceeding.

And specifically, if we look at page 10, lines 27 to 28, and continuing on to page 11, lines 1 and 2, Ms. Garzouzi indicated in the technical conference that a detailed -- sorry, a detailed business case isn't available in the list of stations that were shown in investment SR06 station refurbishment.

So the comment at the technical conference was:

> "We would prepare a business case very shortly before execution, once we've completed our engineering and our site assessment. And that is when we prepare the business case."

So in other words, a business -- a detailed business case won't be available for the project until just before the investment's approved.

In the absence of a detailed scope, though, what's the impact -- what do you see as the impact of that on annual cost estimates? Is there -- are the actuals likely to vary on a project-by-project basis when there is no detailed

scope at the time of the -- at the time of the cost estimates?

MR. BUCKSTAFF: Well, ordinarily when you are doing a big project like this you do cost estimates at several stages, you know, you do one when the idea is first born, when you say we're going to do a project in this area. Roughly what would that cost? You would get a rough estimate, plus or minus maybe 30 percent. Then when you do your preliminary engineering you can make another estimate that gets you greater precision, and then when you actually go to construction, when you're ready to go, you should have a very detailed cost estimate.

But along the way the question is how early can you have those. If you do your engineering a year in advance you'll know that information a long time in advance. If you do your engineering two weeks before you start construction, then you don't have much time.

And some of that depends on what the backlogs are in your engineering group and some of the other things, so there's a variety of factors that affect it. You are going to have multiple stages of estimates, and what's ideal is to have a little bit longer time between when you finish your final estimate and when you build your business case to go forward.

MR. SIDLOFSKY: Is there a reason in your view that a utility couldn't do the detailed cost estimates well in advance of the actual -- of the actual work being done? I realize -- I could imagine that costs will change as you

get closer to construction, but would it be preferable to do the detailed costing and get that detailed scope well in advance of the actual construction?

MR. BUCKSTAFF: Again, as early in the process as possible, you'd like to know the details, but until you have finished the different stages of engineering, you can't really do that because you don't know what the scope of work is. And that does tend to change from the start of thinking about a project until you've reached the final stages where you've finished the full design.

And again, some utilities manage to have that engineering work done a year ahead. Most don't. Most, it's shorter than that. But in a long-term plan you might be able to do that.

MR. SIDLOFSKY: Excuse me. Just one moment, sir.

Have you actually looked at Hydro One's station refurbishment plans in the application?

MR. BUCKSTAFF: I'm sorry --

MR. SIDLOFSKY: Sorry about that. Have you actually looked at Hydro One's station refurbishment plans in its application?

MR. BUCKSTAFF: No, not what's in the application.

MR. SIDLOFSKY: Okay. So this is a more general recommendation; it is not based on your review of Hydro One's actual station refurbishment projects?

MR. BUCKSTAFF: Not anything that was submitted as part of the filing here.

MR. SIDLOFSKY: Okay. Back to page 2, just for the

summary of the recommendations, I'm going to go to substation refurbishment recommendation number 3. And that one calls for Hydro One to develop and implement a more comprehensive set of key performance indicators, including in-progress project cost performance measures and assessments of project and program impacts on substation reliability, maintenance costs, and overall asset health.

Does that mean that at present, the correlation between substation refurbishment project investments and their impacts on substation reliability, maintenance costs and overall asset health is not well supported or quantified?

MR. BUCKSTAFF: In terms of the direct impact on reliability, I'd say it's not -- you know, there isn't that direct tie that you can see easily.

In general terms, what we were trying to get at with this is similar to the other recommendations, better information will enable better decisions. The question of during the progress of a given project there isn't enough information to know are we behind, are we over budget, are we having difficulties, or are we ahead and so on.

The reporting is not as comprehensive as it could be and therefore, you can't make certain decisions during the course of the project. So that would help you.

In terms of the impact of maintenance costs, eventually you'll have those now. It's just you want have them as soon as you might have.

MR. SIDLOFSKY: Sorry, are you able to provide any

view of reliability improvements when any station project has been completed?

MR. GRUNFELD: I'm not. Generally speaking, station refurbishments improve reliability, but the specific magnitude of that impact is not something that we can comment on, or I can comment on.

MR. SIDLOFSKY: Are you suggesting that those outcomes can't really be quantified in terms of SAIDI and SAIFI?

MR. BUCKSTAFF: You can right now, or at the time you wrote this, I don't think Hydro One could. But I have seen instances of other companies who do purport to do that.

MR. SIDLOFSKY: Okay. Is there any industry standard for quantifying that or -- that you're aware of?

MR. BUCKSTAFF: I don't think so.

MR. SIDLOFSKY: Okay. I'm going to move on to vegetation management, and if we could go to page 13 of the compendium, please. At that page we have an excerpt from Clear Path's forestry survey assessment report from November 2017, and that sets out a summary of your key findings and recommendations.

One of those key findings under "Reliability modelling" was that by implementing an optimal maintenance cycle, modified work scope and an analytics-based hazard tree program, it is reasonable to expect a 20 to 40 percent plus improvement of reliability by the end of 2020. That will be the third bullet under section 1.6.

Sir, could you clarify whether all three of those items that are listed are required to achieve a 20 to 40

percent improvement?

MR. TANKERSLEY: To achieve the upper end of that, all three elements would be required. On the bottom end of it, if implemented in an appropriate manner or successfully, you could reasonably expect to get 6.5 percent caused by tree contacts right off the top.

So if you are on a three-year cycle, you are preventing those defects, those that are easiest to identify, and the rest remaining would be through hazard identification, getting off the right away.

I don't think there is any reason that by modifying the cycle, the shorter cycle and modified work scope that 20 percent is -- but just that alone is not achievable.

MR. SIDLOFSKY: Okay. Just to clarify, when you express the 20 to 40 percent, how are you measuring that? Is that 20 to 40 percent of the -- sorry, is the 20 to 40 percent the reduction in the number of outages caused by vegetation, or -- sorry. Could you just tell me what the 20 to 40 percent specifically relates to?

MR. TANKERSLEY: The number of outages.

MR. SIDLOFSKY: Okay. Can we go to the next page, page 14 of the compendium, please? And specifically I'm looking at figures 10 and 11 on that page. There are two graphs in the middle and we've seen those before; Ms. Grice took you to those as well.

Do figures 10 and 11 reflect that 20 to 40 percent reduction?

MR. TANKERSLEY: I believe so. These are all Outages,

including major events. It's representing 20 percent on the bottom end.

MR. SIDLOFSKY: So that's the -- and that's -- that's figure 11 that's showing the 20 percent at the end of the three-year cycle, correct?

MR. TANKERSLEY: Correct.

MR. SIDLOFSKY: So that would be on the low end. Would that mean that in order to achieve that, Hydro One wouldn't necessarily have to take all of those steps in the recommendation?

MR. TANKERSLEY: So there are three key steps in that. It is the shortened cycle, the modified work scope, and then the third one is the analytics-based program. So the first two will get you to a 20 percent, I believe, or greater. And then the third one is something that over time, as you learn more about your system through analytics of what's causing your outages, those that are easiest to prevent through a modified cycle and scope come right off the top.

The others become more difficult, but not that achievable as you are able to apply better practices across your system. That would come at a longer timeframe.

MR. SIDLOFSKY: So that may actually help me understand -- or help me get to the next question here.

I take it the bulk of the projected outage reduction is expected to be achieved at the end of the first three-year cycle.

MR. TANKERSLEY: Which would be the start of the

fourth year.

MR. SIDLOFSKY: Right. And you had mentioned, I think to Ms. Grice, that that's really when you'll start noticing those changes.

MR. TANKERSLEY: No, I would expect that you would start seeing improvements after the first year of the first cycle. But you wouldn't achieve the full -- you wouldn't see the full extent of it until the first -- essentially the first year of the second cycle. But you should be able to see improvements over time.

Now, there are a lot of variables, such as weather. Weather can influence it on one side or the other, but there are certainly ways that you can assess the effectiveness in a shorter timeframe.

MR. SIDLOFSKY: Now looking at both of these figures, it seems that after the first three-year cycle has been completed, then the rate of reduction in outages starts to flatten out.

MR. TANKERSLEY: That is by implementing the first two of the three suggestions in the recommendations.

Now, that flattened -- that will not -- that will continue to improve as you start applying analytics, learnings from your outages that are occurring that go beyond what's in the shortened cycle and the modified basic -- basic modified work scope.

That's and understanding -- well, ideally after the first cycle, your outages are not going to occur as a result of a defect, as I defined earlier; they're going to

be -- that subset of the tree is a larger portion of the population that do not exhibit that defined defect, but what you will find over time is that you will find patterns of occurrences or outages that you wouldn't have defined as a defect earlier but you might going forward.

And so it is the ability to refine your program over time. And this is a, if I understand, a certain species of tree and a certain condition as causing the majority of my outages that was not defined as a defect previously, then I'm going to go out and I'm going to target those.

What I have -- in my experience, what I have learned is that after you have tackled that first level, which is through the base level of defects, you will find patterns that develop, that will say specific areas, certain species of trees, certain conditions that may go beyond that, and then you're able to focus on that, but you're -- the segment of the population is larger and it becomes more difficult, but what might have been previously defined as an unavoidable outage, you might find you will reverse that and say that is avoidable if I do these actions.

MR. SIDLOFSKY: And that's where the analytics comes in?

MR. TANKERSLEY: That's where the analytics comes in.

MR. SIDLOFSKY: So if the utility were to -- if a utility were to stick to those first two items, then we would expect to see a levelling-off. They had have to continue with those practices in order to keep that curve at least level.

MR. TANKERSLEY: That's correct.

MR. SIDLOFSKY: And it is the analytical approach to that work that can help to push from that 20 percent upwards?

MR. TANKERSLEY: Correct.

MR. SIDLOFSKY: Okay. So just to be clear, that baseline maintenance program has to continue indefinitely. Those first two items need to be implemented and they need to be implemented on a permanent basis?

MR. TANKERSLEY: Absolutely. Yes.

MR. SIDLOFSKY: Okay. So just to turn that around a bit, does that mean we wouldn't expect to see more than 20 or so percent improvement without implementing the analytics?

MR. TANKERSLEY: Well, I believe that you will have elements that you will improve on over time that will allow you to gain incremental improvements and reliability. There are things that you can do. The analytics will allow you to take leaps, as opposed to small incremental steps.

MR. SIDLOFSKY: In -- sorry, if I could just go back to page 13, in that same -- in those same key findings, you indicate that an analytics-based hazard tree program requires funding beyond the baseline maintenance levels.

Are there options in terms of funding, or is it really a single program that gets implemented?

MR. TANKERSLEY: Well, from my experience, an effective program will drive the cost of your routine, that first element, down over time, so you are dealing with a

fairly large tree population right now, defect level, and after you get through the first cycle, and I'll characterize this as having your system in control, then it will allow you some flexibility without increasing your previous funding levels to reinvest into the analytics-based system, and potentially you might have a sharing with the savings.

Now, you know, I would advocate improving the efficiency of your base-level program, which is that the cycle scope, and then using savings that are generated over time to reinvest into the analytics program.

I think if you characterize the first group of this, the first year through, the first cycle, we estimate there is about 800,000 existing defects on the system. So 800,000, plus there is going to be about 1.3 million or so defects that will come into play over the next three-year cycle, so a total of 2.1 million trees, roughly.

The start of the second cycle, if it's done properly, you will not be dealing with existing defects; you will only be dealing with preventing future defects. And so that's the challenges of the first cycle versus the second cycle.

The second cycle gives you a lot of opportunity to go into an analytics-based system without increasing your overall cost.

MR. SIDLOFSKY: So it becomes sort of self-funding out of the savings. Is that --

MR. TANKERSLEY: Correct.

MR. SIDLOFSKY: That's the point? Have you estimated what Hydro One's development and operating costs might be for an analytics-based program?

MR. TANKERSLEY: Not specifically, no. It is something that we could do, but...

MR. SIDLOFSKY: And do you know whether Hydro One currently has the information it needs to implement an analytics-based program?

MR. TANKERSLEY: I think they are at a point of starting to develop such a program. The first step is continuing with the outage investigations to fully understand what your outage is, but it is a next-step effort that presumably could be started at any point. They are definitely looking at that.

MR. SIDLOFSKY: Okay. Mr. Quesnelle, I know I'm a few minutes over my time. I just have two more questions if I might --

MR. QUESNELLE: Let's go ahead and finish with this panel before lunch.

MR. SIDLOFSKY: Thanks. And I apologize, sir, I don't have this in my compendium, but at the bottom of page 12 of your November 10th report, you state that:

> "Improvements in tree-related reliability can lead to significant savings in other lines of business. A reduction in the number of outages results in less straight time and overtime payroll for call centre staff, trouble man and line crews. Additionally, there are avoided

costs associated with the reduced number of damaged facilities."

Do you recall that statement?

MR. TANKERSLEY: I do.

MR. SIDLOFSKY: And based on your experience, I'm -- I'd ask you to describe some typical reductions in damaged facilities, so types of facilities that could be spared as a result of improvements in tree-related reliability?

MR. TANKERSLEY: Well, this is -- you can look at this in two areas: storm events and non-storm events. They both occur. In storm events you have many more occurrences of this happening. In storm events, particularly, as many as 50 percent of all interruptions may be attributed to vegetation. Through a more effective vegetation management program you are going to reduce that significantly, and this would be poles down, wires down, everything from the single customer up to major customers. It's the response time for the trouble, for the line maintenance and construction. I mean, it can impact a lot of different areas.

MR. SIDLOFSKY: Thank you, Mr. Quesnelle. I cut it down to one question. It's headed to you. Those are my questions. Thank you, panel.

MR. QUESNELLE: Thank you. We have questions from the Panel.

QUESTIONS BY THE BOARD:

MS. ANDERSON: Mr. Tankersley, we'll continue with you.

So I noticed in the Hydro One's vegetation management trend analysis or their 2016 report there was a reference to cost increases for the, I think it's the peer group had cost increases related to mitigating emerald ash bore and hardening distribution systems against storms.

Were those two factors something that you considered in developing any of your recommendations?

MR. TANKERSLEY: Well, and not just those two factors. There can be things that happen in the forest, disease, Emerald Ash Borer, Dutch elm disease are two. But it could be any number of things. They can be caused by drought. And the longer the cycle, the longer -- not only do you have more of a chance of degradation and service reliability due to tree failures, you've got a very long period before you may even discover it, and so a shorter cycle is going to allow to you monitor the health of the forest that's surrounding your facilities.

So there may be times where a devastating infestation of something, you might need to take remedial actions before. But you have to know about them first, so that definitely is a positive attribute to a shorter cycle.

MS. ANDERSON: Okay. I'm curious because those two factors in particular, the Emerald Ash Borer and hardening of distribution systems, we hear from a number of utilities. So was that -- did you notice that to be any sort of material impact when you were considering, or just one of many factors?

MR. TANKERSLEY: It was one of many factors.

MS. ANDERSON: Okay, thank you. I have a question for Navigant. So you talk about refurbishment and replacement as kind of two strategies. Is there any kind place for run to failure strategies, particularly if there is an assessment for the consequences of failure being minimal?

MR. BUCKSTAFF: That's an option. When you have a run to failure approach on poles, it means typically somebody is out when you have the failure. And that's a choice of are you willing to accept that.

I actually do know of one company who's gotten very closes to that in their distribution maintenance approach, largely because they're very short of funding. And what they show is a six-year decline in reliability; it's just gotten worse and worse and worse.

If you are willing to accept that, then a run to failure approach is okay. But it is not something we generally recommend.

MS. ANDERSON: So when a pole fails, is it -- do you have any information on what percentage of time that results in a power outage? Is it always? I mean, sometimes all the other poles --

MR. BUCKSTAFF: Keep it holding up. Quantitatively, no, we don't have a specific answer to that.

MS. ANDERSON: Okay. Thank you.

DR. ELSAYED: I have a few questions about pole replacement. You mentioned in your report that Hydro One did not have a formal pole refurbishment program.

MR. BUCKSTAFF: Correct.

DR. ELSAYED: So my first question is does that mean that they don't refurbish poles at all, or they don't have a formal program? I don't understand the word "formal"; what does that mean?

MR. BUCKSTAFF: At the time we did the interviews with them and gathered the data, the answer was no, we don't have a refurbishment approach. We replace them when we deem them to have failed.

DR. ELSAYED: So they are just replaced. And then you go on to say that in 13 of the 17 companies you looked at, they do have refurbishment programs in an effort to postpone premature replacement of poles.

Do I take that to mean that with Hydro One not having a refurbishment program, that there is a possibility that they could be replacing poles prematurely?

MR. BUCKSTAFF: The terminology is not necessarily perfect. But a pole that has failed at 20 years -- you know, it's about to fail. In a case where you don't have a refurbishment program, your option is to replace that pole or to leave it standing -- and it's likely to fall over.

If you replace it, that's a premature replacement because you were expecting it to last 60 years. But it really comes down to a choice of I can, at 20 years, replace or refurbish, I can't just leave it alone.

Does that make sense?

DR. ELSAYED: It does, but I'm trying to get a feel of whether your expectation by having -- which is your recommendation, by having a refurbishment, do you think

that would reduce in the long term the cost of pole management in Hydro One?

MR. BUCKSTAFF: Of the entire pole management program, probably yes. It won't cut it in half or anything like that, but it will reduce it some.

DR. ELSAYED: Okay. I want to also clarify the terminology here, I guess. We talked about pole replacement, pole refurbishment, both of which are self-explanatory. Then you talked about a pole management program. I just want to understand in terms of best practice.

In my mind, you can't really separate the two and have a program to replace poles, and another program to refurbish poles. So when you say pole management, would you not have an integrated program that looks at poles in general that includes both aspects of the program as a best practice?

MR. BUCKSTAFF: That's what a pole management program would encompass is both your replacement and your refurbishment, and the management for them. The inspections are part of the pole management program, and then the actions that you take are part of it.

DR. ELSAYED: And the inspections would include a condition assessment of some sort?

MR. BUCKSTAFF: Yes.

DR. ELSAYED: Okay. One of your recommendations as well is to have a dedicated pole replacement crew. Would that not apply to pole refurbishment as well?

MR. BUCKSTAFF: Most of the people that we work with don't have an in-house pole refurbishment program, meaning it's contracted.

So people who are going to come in and do injections, for example, are an outside contractor. So by definition, they are a specialized crew; that's all they do. So the individual utilities typically don't have a crew for that.

DR. ELSAYED: Is that because of the technical nature of the work? Because I would have expected that you would do more refurbishment than you would do replacement.

MR. BUCKSTAFF: What actually happens is you do see more replacement than refurbishment, simply because most poles last their full life. They won't need either replacement early or refurbishment. They will last their whole lifetime.

DR. ELSAYED: My last question is: One of the things you were asked -- or Hydro One was asked to do and you looked at is the internal benchmarking in terms of how -- was that part of your study, the cost of replacement -- the cost of replacement changed over time within Hydro One?

MR. GRUNFELD: You are referring to the trend analysis?

DR. ELSAYED: The trend analysis.

MR. GRUNFELD: So we looked at three years, we collected three years of data and we didn't draw in the report specific conclusions, but you can see from the graphics, if you look at pole replacement, the costs have increased slightly on average for Hydro One.

DR. ELSAYED: So what time period was that? Was that 2012 to 2014?

MR. GRUNFELD: Pardon?

DR. ELSAYED: What was the time period?

MR. GRUNFELD: Three years, 2012 to 2014 inclusive.

DR. ELSAYED: And you said it showed a slight increase in cost?

MR. GRUNFELD: Yes.

MR. BUCKSTAFF: And that slight increase is also reflected in the other companies as well. Everybody has a slight uptick.

DR. ELSAYED: Why was that? Like in your opinion, why would that be?

MR. BUCKSTAFF: I don't have a good answer. It's not like the companies have done something deliberately to raise the prices.

DR. ELSAYED: No, but I guess in my mind it would seem to me that when you have some experience and you lessons learned that you will do better as time goes by.

MR. GRUNFELD: Generally speaking, it is driven by inflationary pressures. Companies have been doing pole replacement for 50 to 100 years, and obviously the processes that they undertake evolve and improve over time.

But a large portion of the cost is either labour or the material, which are both subject to inflationary pressures.

DR. ELSAYED: Okay, thank you.

MR. QUESNELLE: Just one area that just came to mind.

Hydro One has an expected life of a pole -- and I forget what the number is, fifty-two years or...

MR. BUCKSTAFF: Sixty-two.

MR. QUESNELLE: Sixty-two. Does that line up with their amortization? When you are doing your analysis and you've got a fully depreciated analysis, is it 62 years that they're using, or can you talk to me about the...

MR. BUCKSTAFF: I don't know the answer on the accounting, how they do their depreciation.

MR. QUESNELLE: So your analysis didn't need to...

MR. BUCKSTAFF: No, we didn't include that. I will say that having done that for a couple of other companies, the accounting depreciation is quite different from the expected life for the couple of companies I've done anything on that with.

MR. QUESNELLE: Well, we'll follow that up with the asset people then. Thank you very much. That's all we have. Do you have any re-direct, Mr. Nettleton?

MR. NETTLETON: Yes, I do, sir. I just have one matter arising.

Gentlemen, if you could turn to page 7 of the Staff compendium, which is section 3.6 of your report -- do you have that?

MR. TANKERSLEY: Yes.

MR. NETTLETON: You were talking to my friend Mr. Sidlofsky about the seven times more expensive metric or statistic that's found in that this passage. Do you see that?

MR. GRUNFELD: Yes.

MR. NEME: Did you -- and Mr. Sidlofsky went on to talk to you about the potential refurbishment of a 50-year old pole; do you remember that?

MR. GRUNFELD: Yes.

MR. NEME: Did you have occasions in this report to ask any questions or assess whether the entities that you spoke with or assessed in this study were refurbishing 50-year old poles?

MR. BUCKSTAFF: We didn't ask it directly as part of this study. In a couple of other individual projects with people we've asked that kind of question. It's always been: No, we don't replace -- or we don't refurbish really old poles, we refurbish ones that are prematurely failing. So 20-year-old, not 50-year-old poles.

MR. NETTLETON: And would you have any reason to believe that the metric or the statistic that you've used of the seven-times more expensive factor for refurbishing versus replacing would apply to a pole that was 50 years old?

MR. BUCKSTAFF: I don't know. I mean, I don't know anybody who has refurbished a 50-year old pole.

MR. NETTLETON: Thank you, those are my only questions.

MR. QUESNELLE: Thank you, Mr. Nettleton. We'll break for lunch until 2:15. Thank you very much, panel.

--- Luncheon recess taken at 1:14 p.m.

--- On resuming at 2:25 p.m.

MR. QUESNELLE: Welcome, panel number 5.

MR. SIDLOFSKY: Sir, just before we begin, I believe Ms. Grice has one preliminary matter.

PRELIMINARY MATTERS:

MS. GRICE: Thank you. So at the break, I took a look at undertaking J1.8, which is the undertaking that I was following up on this morning. Maybe we could put that up on the screen, J1.8.

The undertaking is to provide a version of the table to support tables 4 and 5, estimated input to SAIFI and forecasted SAIDI hours. The response to the undertaking indicates that this information was provided in the technical conference undertaking Exhibit JT3.10, as well as an interrogatory, Staff 164.

And you'll recall in my discussion with panel 1, I explained that I had the evidence and I had this interrogatory and this undertaking, and I was still having difficulty recreating the numbers in tables 4 and 5.

So I asked if there was an underlying spreadsheet that supports the tables, and is that something that Hydro One could provide before panel 5. And I'm just referring to the transcript from panel 1 and the response by Mr. D'Andrea was:

> "So we can't answer whether there is a spreadsheet or not behind this, or what supports that, but we're willing to take an undertaking on it."

And that's what led to this undertaking.

So what I'm finding now is I'm being referred back to the same interrogatory and undertaking that I explained I was having difficulty using to recreate the tables. And my understanding is that there are other parties that are interested in this underlying calculation.

If we look at the chart there, the charts provide information and assumptions that define capital plans A, B, C, and B modified. So given the chart form, I'm assuming there is an underlying Excel spreadsheet that supports the data.

So that's what I'm looking for. And if we want to bring up the charts, if that would be helpful, it's the rows and the calculations of the percentage changes in SAIDI and SAIFI that I'm having trouble recreating.

MR. QUESNELLE: Thank you, Ms. Grice. Mr. Nettleton?

MR. NETTLETON: Thank you, Ms. Grice, for that clarification.

It strikes me, Mr. Chairman, that it might be -- one solution, just to make sure that we are aware of exactly where the gap is, is for Ms. Grice to have a discussion with -- and I believe it would be Mr. Jesus about this information, and to see if Mr. Jesus can help explain what the numbers are and how they were calculated, and how they came into tables 4 and 5.

I even don't know whether there is a spreadsheet or not, but I would think that if there's a gap, then lets have questions. And if there is something missing, then we deal with it through undertakings.

MR. QUESNELLE: Okay. Well, let's do that now just so that we know what to expect before panel 5 is finished with its cross-examination.

Do you want to start off the panel and have them affirmed first?

MR. NETTLETON: Yes, I think if we could get them sworn.

MR. QUESNELLE: Let's do that and we will revisit this as an order of business, though.

MR. NETTLETON: Panel, it is my pleasure to introduce to you panel 5. This is the asset management, investment planning and work execution panel.

We have five witnesses with us today. Seated closest to you is Mr. Bruno Jesus. Mr. Jesus is director of strategy and integrated planning with Hydro One.

Seated beside Mr. Jesus is Ms. Lyla Garzouzi. Ms. Garzouzi is the director of distribution asset management.

Seated beside Ms. Garzouzi is Ms. Darlene Bradley. Ms. Bradley is the vice-president of planning for Hydro One.

Finally, to her right is Mr. Brad Bowness, and Mr. Bowness is the vice-president of distribution for Hydro One.

Ms. Anderson, if the oath could be administered, that would be great.

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

Darlene Bradley,

Bruno Jesus,

Lyla Garzouzi,

Brad Bowness; Affirmed

EXAMINATION-IN-CHIEF BY MR. NETTLETON:

MR. NETTLETON: Thank you. Panel and Mr. Chairman and Board members, the curriculum vitae for this panel, the witnesses on this panel were pre-filed on June 7th as part of Exhibit A-9-2.

On the first day of the hearing, we had Exhibit K1.2 marked and you will recall that that was the draft hearing plan. And at pages -- PDF page 33 of 58 is the starting of the evidence that this panel is responsible for.

So witnesses, can each of you confirm that you have responsibility for the evidence that is listed on that exhibit and on that chart and assigned to your names. Mr. Bowness?

MR. BOWNESS: Yes, I do.

MR. NETTLETON: Mr. Bradley?

MS. BRADLEY: Yes, I do.

MR. NETTLETON: Ms. Garzouzi?

MS. GARZOUZI: Yes, I do.

MR. NETTLETON: Mr. Jesus?

MR. JESUS: Yes, I do.

Starting with you, Mr. Bowness, do you have any changes or directions to make to that evidence assigned to you?

MR. BOWNESS: No, I do not.

MR. NETTLETON: Ms. Bradley?

MS. BRADLEY: No, I do not.
MR. NETTLETON: Ms. Garzouzi?
MS. GARZOUZI: No, I do not.
MR. NETTLETON: Mr. Jesus?
MR. JESUS: No, I do not.
MR. NETTLETON: And it is therefore accurate to the best of your knowledge and belief, Mr. Bowness?
MR. BOWNESS: Yes.
MR. NETTLETON: Ms. Bradley?
MS. BRADLEY: Yes.
MR. NETTLETON: Ms. Garzouzi?
MS. GARZOUZI: Yes.
MR. NETTLETON: Mr. Jesus?
MR. JESUS: Yes.
MR. NETTLETON: And do you therefore adopt this evidence as your evidence in this proceeding, Mr. Bowness?
MR. BOWNESS: I do.
MR. NETTLETON: Ms. Bradley?
MS. BRADLEY: I do.
MR. NETTLETON: Ms. Garzouzi?
MS. GARZOUZI: I do.
MR. NETTLETON: And Mr. Jesus?
MR. JESUS: I do.
MR. NETTLETON: Thank you. Mr. Chairman, I believe Ms. Bradley has an opening statement that she would like to make.

OPENING STATEMENT BY MS. BRADLEY:

MS. BRADLEY: Good afternoon. My name is Darlene

Bradley and I am the vice-president of planning at Hydro One. My team and I are responsible for the preparation and content of the distribution system plan and in doing so, we work closely with Mr. Bowness and his team, who have overall accountability for executing the work and activities that are presented in the plan.

I am pleased to be here with you this work to share some of the things that we are doing in operations at Hydro One.

I've been with Hydro One for thirty years, and I have to say it is exciting to be leading the transformation that's taking place.

In my career, I've seen and been a part of a number of improvement initiatives, and I was and continue to be very proud of those initiatives. But I must say the focus and commitment and our pursuit of excellence is beyond what I have seen.

I believe the amazing skills and experiences we have within our team are critical to achieving the results that we're committing to you, but it's more than that. It's the alignment and purpose and vision and the outcomes that we're focused on.

I'd like to talk to you today about three subjects: the distribution system plan and how we will manage to a multi-year plan; our commitment to continuous improvement and the resulting interchanges in the plan since we originally filed; and lastly, I'd like to give you an update on our 2017 results and our progress so far this

year.

The distribution system plan that forms part of this application before the Board was prepared in 2016. The challenges that we faced two years ago, and those that continue to be at the forefront of our iterative planning process, are based on finding the right balance between our customer needs, the needs of our assets and our system, and managing the impacts of our customer rates.

We know that our asset investments, the needs continue to be greater than what can be tolerated in the rates paid by our customers.

It is our accountability and at the very core of what we do in asset management to strike the appropriate balance between customer needs, the needs of the system and the assets and our customer rates.

The decisions we make today unpack the availability of safe, affordable and reliable power for today, tomorrow and future generations. We're committed to delivering on the aggressive outcomes and prescribed objectives of the proposed five-year distribution system plan that's currently before this Board. We will do so while being nimble and responsive to changes that are driven by our customers, by our system and system needs, by the forces of mother nature and our relentless pursuit of operational excellence.

We will continue to drive continuous improvement in all aspects of our business for the benefit of our customers.

We have improved our planning and redirection processes, recognizing the dynamics that exist. Central to this notion are having the necessary resources, processes, and people to manage the corresponding impact of the ever-changing requirements.

Our processes, including our annual investment planning process and our monthly redirection process, allow us to respond and manage the intrinsic dynamics of a five-year plan.

Operational excellence and continuous improvement are embedded in the distribution system plan, and our commitment is further evidenced through the increases in efficiency, productivity, and improving reliability outcomes that we have made since the time of this application.

These outcomes are fundamental to our commitment to continuous improvement and are the key element of the OEB's renewed regulatory framework outcome of operational effectiveness.

We have heard the message in the OEB's March 12th, 2015 decision, where they advised that we should be finding cost-effective ways to improve performance, and we have taken action.

We will continue to assess our work programs, much as we did with vegetation management, to identify ways to increase productivity and reliability through continuous improvement and operational excellence. We will improve through assessing everything we do. No stone will remain

unturned as we work relentlessly towards improving the reliability and cost for our customers.

Over the five years of this plan we have made significant changes from our last application, both in productivity and in reliability. In productivity we have incorporated close to $400 million. This is almost 15 times more in annual savings than was in our last application. In reliability we have set aggressive targets for our -- in our electricity distribution scorecard, in our distribution OEB scorecard, and in our Hydro One team scorecard. We've done so through enhanced work programs, enabling us to update our reliability outcome, projecting more than a 25 percent improvement without increasing the revenue requirement. This is achieved through new ways of doing things, including our changes in vegetation management and our new worst performing feeders program.

We will continue to assess our assets, our programs, and our processes. We need to address our end-of-life assets and we will continue to look for ways to accomplish more with less.

Step changes in performance often include new ways of doing things. We have a team committed to leading this type of transformation. As we progress through the five years of this distribution system plan, we will continue to assess and advance initiatives and programs through our risk-based approach to identify and execute on productivity and reliability initiatives, and we'll work within our capital and OM&A envelopes.

As an example of what we've been able to achieve with these new approaches as our vegetation management program, this will allow us to transform our right-of-way maintenance clearing while remaining within the funding envelope.

The benefits we expect to gain are a reduction from our current ten-year cycle to a three-year cycle, with a new focused scope of work which will help us address the backlog of circuits that haven't been cleared in many years, a reduction in the associated safety risks, and significant improvements in reliability. We expect our vegetation-caused outages to be reduced by about 40 percent compared to our five-year average.

The initial requirement of $150 million for this program is $17 million less than was in our last application, and it is the minimum we must spend in the initial years to get this program started and to maintain a three-year cycle. We do expect that up to $20 million of additional savings is possible once we reach 2023.

Other examples of continuous improvement initiatives underway are our worst performing feeders program, where we've conducted detailed analysis of each event that has resulted in the interruption of service to our worst served customers, and we've developed solutions that are specific to each location.

In some cases we are anticipating reliability improvements of more than 60 percent with this program. This means some customers will not experience interruptions

that they would have in the past and those who do will see their power restored much quicker.

You've heard from panel 1 about changes we have made in our processes and governance framework for identifying and tracking productivity, and you can see through our application in the updates we've made that this is an ongoing commitment.

I've outlined a number of examples to give you an idea of the changes that we're making right now and expressed our commitment to continuing this journey or pursuit of operational excellence.

I'd like to close by updating you on our 2017 results and our progress so far in 2018. On May 4th of this year we filed our 2017 actual results with the Board. These form the most recent numbers in evidence. Over the course of the last three years, that is, 2015 to 2017, our capital investments have been in line with the OEB-approved amounts. There have been some variances year to year, but over that three-year period they were very much in line.

Historically our in-service additions were above OEB-approved levels. We have worked diligently to tighten this, and in 2017 the in-service additions came within 2 percent of the OEB-approved amount.

In 2017 our OM&A came in at about $34 million, or 5.8 percent below the OEB-approved amount. Primary contributors to this were the adjustment to reassess programs such as vegetation management and PCB programs as we reassessed better ways of doing things.

Contrary to competing factors such as inflation, expansion of our distribution system, and the increasing maintenance demands of a deteriorating distribution system, our OM&A in the 2018 test year is $16 million, or about 2.7 percent lower than the 2017 OEB-approved amount. This is a testament to our pursuit of efficiency and productivity initiatives.

We're now almost halfway through 2018 and we're on track to executing on our Plan B modified, which formed the basis of this application. We're executing this with a new vegetation-management program, and as expected we have adjusted for the changing realities that we face day-to-day.

For example, this spring, we've experienced three very significant storms which collectively impacted about $1.3 million customers, resulted in unscheduled replacement of about 1,000 distribution poles, with restoration costs totalling nearly $40 million. Each individual storm was bigger than any one of the storms that we had in 2016 or 2017.

These are the dynamics and ongoing changes of our operating environment that I spoke about earlier, the ones that we have evolved our redirection process to account and respond to.

While our actual 2018 work is not identical to what is in our application, we are on track to our budget and we are continuing in our pursuit of continuous improvement and operational excellence to deliver safe, reliable, and

affordable power to our customers.

I hope you've given -- I've given you a flavour for the difference that exists in our approach and our commitment to continuous improvement and operational excellence.

You may recall during the executive presentation day on December 7th, 2017 our president and CEO Mr. Mayo Schmidt shared with you his vision for Hydro One and our purpose. Mr. Schmidt comments that we can provide evidence that we are an organization that is learning to be responsive and is listening. I believe that the application before the Board and the resulting changes to the application since we filed embody that evidence, the evidence which demonstrates our unwavering commitment to our purpose, to operational excellence, to listening and responding to our customers, to the Board, and to others who have provided us with valuable insights.

I hope I have given you some view into our enhanced ability to listen and to be responsive. We are aware of the trust that has been placed in us, and we must manage these commitments with an eye to today, tomorrow, and the future.

I know that some questions were asked last week with respect to planning, including our commitment to our capital program, in light of our new vegetation management program and the impact of data on our ability to make sound planning decisions. We look forward to discussing these items with you.

Mr. Chairman, distinguished members of the Board, counsel, and intervenors, thank you for allowing me the opportunity to speak to you today, and our planning panel welcomes the questions on planning and execution evidence. Thank you.

MR. QUESNELLE: Thank you.

MR. NETTLETON: With that, Mr. Chair, this panel is available for cross-examination.

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

Why don't we deal with an issue that Ms. Grice raised, and we'll get that cleared out of the way so we know what to expect.

Mr. Jesus, you heard the conversation, and I believe you and Ms. Grice took us to the transcript from when panel 1 was with us last week. I wonder if you could provide some -- any information you have on that.

MR. JESUS: Sure. So exactly what is the -- sorry? Exactly what is the issue in reproducing the table, Ms. Grice? Can you elaborate on what the concern is or what the difficulty is, and I'll be gladly (sic) to take you through it.

MS. GRICE: Okay. Well, why don't we start by pulling up the evidence with Tables 4 and 5.

MR. JESUS: Okay.

MS. GRICE: So if we can please go to Exhibit A, tab 3, schedule 1, page 16.

MR. JESUS: Can I take you to -- rather than taking you there, can I take you to the most updated table, which

is Energy Probe 17? Is that acceptable?

MS. GRICE: Sure, sure.

MR. JESUS: So I-18 Energy Probe 17 is the most up to date table that we've produced.

MS. GRICE: So my understanding -- the difference between where I was going to take you and this interrogatory response is in the original evidence. You provide this table for the average of 2013 to 2015, and then you updated the table here to bring in 2016.

So this is precisely my point, is that in order to update this table with new information, new requests, new -- for example, the vegetation management program in the original application was the old vegetation management strategy.

So when you look at the columns for plan A, B, C and plan B modified, I'm having difficulty moving from the first column and recreating it all the way that I get the same percentages for the forecasted impact on SAIDI.

So given that you were so readily able to update the table in this interrogatory, is there an underlying spreadsheet that you used to calculate these numbers that you put in the table? That's what I'm looking for.

MR. JESUS: So we don't have an underlying spreadsheet. We built this table, so if you want the spreadsheet that we've got, we can provide it. But effectively, it's the numbers that you see here and I can take you through how we calculate it.

All the calculations are underpinned by I29, Staff

164.

MS. GRICE: Okay. Maybe if I could get that underlying spreadsheet I could clear up what my issues are.

MR. JESUS: When I say underlying spreadsheet...

MR. QUESNELLE: The microphones are connected, so if one of you shuts them off, they both go off. Perhaps it's on now.

MR. JESUS: Okay. So when -- I'm being -- I'd be more than glad to produce that spreadsheet, but all you're going to get is numbers and just multiplications in terms of how we got the 7.4. The 7.4 is founded on AMPCO 13, which provides all of the SAIDI numbers over the last five years. All that is is an average over the period of '13 to '16, so that's how we end up with 7.4.

The contributions to SAIDI, we take you through, again from AMPCO 13 where we have the contributions by various causes. We end up with the average over those five years to come up with 6 percent due to poles, 2 percent due to stations and other line components.

When we talk about other line components and poles, it is really about -- we call it defective equipment, so it is really the combination of those two.

So if you look back over the past five years, you will see that when you add up the poles and the other line components as well as the stations, they should sum up to the average of the five years from a defective equipment perspective.

Then the underlining calculations in terms of had you

we get 12 percent, 10 percent, they are provided again in I-29, Staff 164, as well as appended by JT3.10.

MS. GRICE: Okay.

MR. QUESNELLE: So I want to go further, Mr. Jesus, but I'm just going to suggest that perhaps the provision of the spreadsheet along with the narrative you just provided on the transcript would assist. Ms. Grice?

MS. GRICE: Yes, it would. Thank you.

MR. JESUS: Okay, thank you. We'll provide the spreadsheet.

MR. SIDLOFSKY: Perhaps we could make that a new undertaking number because there was a response to undertaking J1. --

MR. QUESNELLE: Good idea.

MR. SIDLOFSKY: J6.1.

UNDERTAKING NO. J6.1: TO PROVIDE THE SPREADSHEET AND AN EXPLANATION OF HOW IT WAS DERIVED

MR. QUESNELLE: Mr. Rubenstein?

MR. RUBENSTEIN: Thank you. Anyway, we just came back from lunch. I am wondering if there is a sense of when you wanted to take a break. I'm tired after the spreadsheet already.

MR. QUESNELLE: Let's go to 3:30.

CROSS-EXAMINATION BY MR. RUBENSTEIN:

MR. RUBENSTEIN: All right. Thank you very much. Panel, I have a compendium of documents. I don't know if Board Panel has it, if we could have that marked.

MR. SIDLOFSKY: That will be Exhibit K6.2.

EXHIBIT NO. K6.2: SEC CROSS-EXAMINATION COMPENDIUM FOR HONI PANLE 5

MR. RUBENSTEIN: And the compendium includes materials from the record of this proceeding and materials from the last proceedings, as well as a spreadsheet that I provided -- those materials that I provided to my friend yesterday morning.

The compendium contains most of the information I'll be referring to. There is some stuff that accidentally got left out, but I'll ask -- is this better?

MS. BRADLEY: That's better.

MR. RUBENSTEIN: I'd like to start off at a high level, just to get a sense of what the capital request is and to situate this application.

If we can turn to page 2 of the compendium, this is your response to SEC 38 which you filed last week. Do I have that correct?

MS. BRADLEY: Yes, that's correct.

MR. RUBENSTEIN: And this provides some of the most up-to-date tables, as I understand it.

If we flip through and we move to page 4, this table has the 2013 to 2017 capital expenditure numbers for Hydro One. Do I have that correct?

MS. BRADLEY: Yes, that's correct.

MR. RUBENSTEIN: And what it shows is that if we add up the totals in the actual columns for the last five years, Hydro One spent approximately 3,235,000,000 in capital expenditures. Do you accept that, subject to

check?

MS. BRADLEY: Subject to check, yes.

MR. RUBENSTEIN: And if we flip over to page 5, this is the proposal for the custom IR period. Do I have that correct, the capital expenditure request under "total"?

MS. BRADLEY: Yes, that's correct.

MR. RUBENSTEIN: And when I add that up, I get about 1 -- when sorry, when I add that up I get 3.571 billion in the forecast expenditures. Do you accept that, subject to check?

MS. BRADLEY: Sorry, you said three...

MR. RUBENSTEIN: 3.571.

MS. BRADLEY: Yes, that's correct.

MR. RUBENSTEIN: So in this five-year period, it appeared to me you're forecasting to increase the capital expenditures over the previous five-year period by about 10.4 percent?

MS. BRADLEY: Capital expenditures are increasing, yes.

MR. RUBENSTEIN: Would you take it, subject to check, that just these five years over the last five years, it's about a 10.4 percent increase?

MS. BRADLEY: Subject to check, yes.

MR. RUBENSTEIN: And if we look through the various categories of spending, the system -- access system, renewal system, service and general plant, the largest changes, as I see it, is reduction in system access, which I understand is primarily non discretionary investments and

its increase in system renewal.

MS. BRADLEY: That's correct.

MR. RUBENSTEIN: And if we turn to page 7, we have -- we see the in-service additions between 2013 and 2017. And I see that you brought into service about $3.442 billion; do you accept that, subject to check?

MS. BRADLEY: I'm sorry, can you repeat? I was just trying to follow your table here.

MR. RUBENSTEIN: Sure. As I'm looking at table 1 on page 7, this shows the actual and approved spending over the five years on an in-service additions basis. And if I just look at the actual spending, I get that you brought into service, between 2013 and 2017, about $3.442 billion; do you accept that, subject to check?

MS. BRADLEY: Yes.

MR. RUBENSTEIN: And then if we look at table 8, this is the forecast in-service additions -- sorry, on page 8, if we look at table 6 on page 8, we see the in-service capital addition forecast between 2018 and 2022, what this application is based on; do I have that correct?

MS. BRADLEY: Correct.

MR. RUBENSTEIN: And what I see when I add all those numbers are up, you are seeking in-service additions of $3.628 billion. Do you accept that, subject to check?

MS. BRADLEY: Yes.

MR. RUBENSTEIN: So you are seeking to add about 5.4 percent more in-service during the test year than you did in the previous years, correct?

MS. BRADLEY: Correct.

MR. RUBENSTEIN: If we turn back to page 7, what we see -- and I think you discussed this in your opening -- but if we take a look at what the actuals were versus what you were approved in the last Board proceeding from 2015 to 2017, it looks like you brought into service an additional $122.5 million. Do I have that right? It's about 6.2 percent more?

MS. BRADLEY: Sorry, which lines are you looking at right now?

MR. RUBENSTEIN: I'm just -- if we take a look at the 2015 to 2017 actuals versus OEB-approved, I have that you brought into service $122.5 million more than was approved; do I have that correct?

MS. BRADLEY: Yes, you do.

MR. RUBENSTEIN: So that's about 6.2 percent more than approved?

MR. BOWNESS: Sorry, if we look at the in-service addition summary, which was Exhibit D1, tab 1, schedule 2, that would have had the cumulative totals, correct, which would have been -- which would have had a variance of 2015 of 104.6 million, a variance in 2016 of 33.2 million, and then a 2017 negative variance of negative 44.2, so the rough math on that in my head is about a $95 million variance.

MR. RUBENSTEIN: All right. Well, when I do the math, looking at your table, we get 122.5.

MR. BOWNESS: Okay. Yes. So there was a -- with the

most recent updates there is an additional 31 million as compared to the pre-filed evidence, so, yeah, that would account for the difference, so that's correct. I'm sorry.

MR. RUBENSTEIN: Okay. So just so we're clear on the record, the difference is 122.5 million.

MR. BOWNESS: Yes, that's correct.

MR. RUBENSTEIN: And that's about 6.2 percent more than what was approved, correct?

MR. BOWNESS: Cumulative across the three years, yes.

MR. RUBENSTEIN: And am I correct that in the 2013-0416 proceeding the Board granted you your entire request with respect to capital expenditures and in-service additions? Do you want me to pull up the decision?

MS. BRADLEY: Yeah, I'd have to look at the decision.

MR. RUBENSTEIN: Well, if we could pull up the -- go to page 37 of the 416 decision. We see this right under "findings". The Board says:

> "The OEB has determined it will approve Hydro One's proposed rate base and corresponding capital expenditures plan for the 2015 to 2017 period as submitted."

MR. BOWNESS: Yes, for those three years. I thought you were mentioning 2013's approved funding. That's where the confusion was.

MR. RUBENSTEIN: No, I'm just talking about the last proceeding --

MR. BOWNESS: The last proceeding for 2015 to '17, yes.

MR. RUBENSTEIN: All right. So not only did you spend what the Board approved for you to spend, you spent 6.2 percent more than that?

MS. BRADLEY: Correct.

MR. RUBENSTEIN: And you are seeking to add that to rate base in this proceeding. You are seeking approval to include that in the rate base going forward. Do I have that correct?

MR. BOWNESS: Yes, we're seeking to true-up for the actuals that have been in service over the previous period, as well as the approval to move forward with the five-year plan.

MR. RUBENSTEIN: And I take it by your request you believe that ratepayers should have to pay for this -- for your overspending over the past three years, compared to approved?

MR. BOWNESS: So as the process works, we own the risk during the rate filing period for any variances that occur during the execution of the work program as compared to the plan, and then we come back here and we need to explain the variances and seek approval from the Board based on those explanations, and we believe we've provided that information in the in-service addition exhibit update, which was D1, tab 1, schedule 2, as to the reasons for the changes, but if there's further questions on the reasons for the variances I'm happy to respond to those questions.

MR. RUBENSTEIN: No, but I take it -- so then your answer is, yes, you believe ratepayers should, going

forward, have to pay for the additional $122.5 million of in-service additions --

MR. BOWNESS: Yes, we believe that the expenditures over the prior period are prudent and that they were required in order to meet the plan needs as well as some emergent needs, especially with respect to joint-use work that we did, as well as storm volumes that were over plan in the 2015 period.

MR. RUBENSTEIN: Even though the Board gave you everything you needed, you needed some more?

MR. BOWNESS: Things did change, yes, and we've explained those variances.

MR. RUBENSTEIN: All right. So let's take a look at what you did during the last few years, and if we can turn to page 25 of the compendium. So you were asked in interrogatory AMPCO 22, part A for an analysis of the actual accomplishments of work compared to the investment plan between 2014 and 2017; do you see that?

MR. BOWNESS: Yes, I see that.

MR. RUBENSTEIN: And if we move over to the next page, where you provide your response, I see a lot of negative numbers, mostly negative numbers; would you agree with me?

MR. BOWNESS: Yes, I would agree that the majority of the unit count numbers are negative.

MR. RUBENSTEIN: And if we go down -- am I correct that where we see in the -- at the table ISD, that means -- and we see the S numbers, S is what you called, at least in the last proceeding, sustaining category of investments; am

I correct?

MR. BOWNESS: Yes, that's correct.

MR. RUBENSTEIN: And those generally map to system renewal? I know it's not perfect, but that's a general type?

MS. GARZOUZI: Generally, that's correct.

MR. RUBENSTEIN: And just -- so if we just look at some of these, I see that you did less transformer replacements than you said you would do in the last proceeding? Do I have that correct?

MS. GARZOUZI: That's correct.

MR. RUBENSTEIN: Less station refurbishments? Do I have that correct?

MS. GARZOUZI: That's correct.

MR. RUBENSTEIN: Less pole replacements? Do I have that correct?

MS. GARZOUZI: That's correct.

MR. RUBENSTEIN: Less PCB lines requiring replacements? Do I have that correct?

MS. GARZOUZI: That's correct.

MR. RUBENSTEIN: Less large sustaining initiatives?

MS. GARZOUZI: That's correct.

MR. RUBENSTEIN: So if we look at each of the ISDs in there, every single one that has an "S", so sustaining programs, every single one shows that Hydro One replaced less assets and did less work than you said you would do over 2015 to 2017; do I have that correct?

MS. GARZOUZI: The table in AMPCO 22 is an insular

table, it is very focused, it provides the program that you just listed.

When we look at work accomplishment, it is a more complex picture. I think we need to step back a little bit to see what is accomplished.

An example is around sustainment initiatives. A project is not -- all projects are not equal. There is a lot of variation in project count, so the project in itself, the accomplishment of it is not a reflection of accomplishment.

If we look at the wood pole replacement as an example, while it was slightly under-accomplished, it was still 91 percent accomplished. And if we look at stations here, we see that the planned refurbishments were under, but we did have numerous unplanned or demand failures that were addressed. Those can be found in AMPCO 25.

And so I think that, looking at this very specifically, we see that sustainment is under-accomplished, but when we step back and we look at all the categories, there is puts and takes from a Hydro One perspective.

MR. RUBENSTEIN: Sorry, just back to the question I was asking, if we look at each of the sustaining ISD programs or projects that you have listed, I'm correct that every single one you did are negative numbers. You did less work than you said you would in your last proceeding. That's what this table is showing me. Do I have that correct?

MS. GARZOUZI: From that perspective, that's correct.

MR. RUBENSTEIN: So in the last application, the Board gave you all the money you needed -- you asked for, and yet you didn't do the work that you said you were going to do; do I have that correct?

MS. GARZOUZI: There are external factors occurred. We had -- we experienced more severe storms, as Darlene Bradley mentioned. We accelerated the CDMA replacement so there were demand factors that occurred, and so we accounted for those, and that's why you're seeing some negatives in this table.

MR. RUBENSTEIN: Well, in development capital as well I'm seeing less new connections, less service upgrades, less service cancellations, less upgrades driven by growth, less asset life-cycle optimization and operational efficiency, less reliability improvements; do I have that correct as well? So the "D", which I -- development, I believe, was the previous term, those are, my understanding, demand-based, those are all also negative numbers.

[Witness panel confers]

MS. GARZOUZI: So that's correct, that the development project accomplishment listed in AMPCO 22 is under accomplished, but we had some changes and we redirected funding to other areas of the business.

MR. RUBENSTEIN: Am I correct that you are still going to need to do some of the work that you obviously didn't get to between 2015 and 2017, correct, with respect to

sustaining capital specifically? You still need to replace some poles, you still need to refurbish stations, correct?

MS. GARZOUZI: Correct.

MR. RUBENSTEIN: So they just got pushed into this application?

MS. GARZOUZI: They got deferred.

MR. RUBENSTEIN: Could I ask you to turn to 28 -- or 27 of the compendium?

We had asked you in SEC.42 to fill out a spreadsheet. If we can turn to page 28, we see the spreadsheet and essentially what it asked you to do was -- we took a table from the last proceeding, and we asked you to fill out, on the same basis, what you spent in those various categories; do you see that? I've summarized what this table is, correctly?

MS. GARZOUZI: Yes.

MR. RUBENSTEIN: And you were able to provide information for between 2015 and 2017, but my understanding is you couldn't do it on a going-forward basis because the program numbers have changed and they are being reorganized.

Do I generally have that correct? Not for all of them, but for some of them, that's what I understood.

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

MR. RUBENSTEIN: And if I could ask you to turn to page 30, this is SEC 52 and we again asked you to fill out another table. And if we flip over to page 31, we see that table and essentially it is a similar basis we -- and I

think this is actually where you got the numbers from, the numbers match up to our previous table we were looking at. This is on an asset basis. We asked you what did you say you were going to do and then what the assets that you did do and going forward.

Do I have that correct, what this table is representing?

MS. GARZOUZI: That's correct.

MR. RUBENSTEIN: If you go to page 32, this is a chart we put together to look at them both of them at the same time for the sustaining category. And what the chart shows is for each of the programs or projects, we have the costs and the assets and the unit costs, just taking the assets and dividing them by the costs in the first set of columns for the -- what was in the EB-2013-0416 proceeding. Do you see that?

MS. GARZOUZI: I do.

MR. RUBENSTEIN: And in the next three columns, we have the same thing. But what you showed that you did do for 2015, 2016, and the costs, the actuals, do you see that?

MS. GARZOUZI: Yes.

MR. RUBENSTEIN: And we also then calculated a unit cost by taking the assets and dividing by the costs; do you see that?

MS. GARZOUZI: I do.

MR. RUBENSTEIN: And then we have the unit costs in the last row, and this is calculating the change in unit

cost versus what you said you would do and what you did do; do you see that?

MS. GARZOUZI: Yes.

MR. RUBENSTEIN: And I provided the spreadsheet to Hydro One yesterday. You may not agree with what I did, but was there any -- did you look at the numbers? There was no calculation errors? I want to make sure we're not argue about...

MS. GARZOUZI: I didn't verify your calculations, but I'll take them, subject to check.

MR. RUBENSTEIN: Okay, thank you very much. If we take a look at the comparison column, that's what I want to focus on. What I see for transformer spares and replacements is on a unit cost basis, you were below, which is a positive in my mind, for 2015. You were above in 2016 and then you were below again in 2017; do you see that?

MS. GARZOUZI: Yes.

MR. RUBENSTEIN: Then for mobile unit substations, do you see that there's two division errors in the Excel spreadsheet and that's because you spent money, but you actually -- there's no mobile unit substations.

Can you help explain that?

MS. GARZOUZI: So what you see there is the difference between in-service additions and capex, so it's the delay between the receiving of the unit and the spend on the unit. And so the vendor was delayed, and that's why you don't see the unit as a count. So it's a capex ISA.

MR. RUBENSTEIN: So the assets are in --

MS. GARZOUZI: ISA; when you receive it, it's ISA and you spend when you're buying it.

MR. RUBENSTEIN: Is that for all of the -- would that be similar for all the entities is, or is that just for that one? So when you say an asset, you have asset in your assets, is that on a capex basis or in-service additions basis?

MS. GARZOUZI: Typically for lines assets, the ISA and capex, it matches. It is usually very close to 90 to 100 percent.

On the stations asset, there is more an in-service element that is very important, and so you will see that more prevalent in the station refurbishments, the MUS procurement, the demand work less so because it's occurring in real-time essentially.

MR. RUBENSTEIN: All right. Well, if we go down that table, we have spill containment and it shows two times, one and a half times more than you had forecast on a unit cost basis; do you see that? 196.7 percent and 167 percent.

[Witness panel confers]

MS. GARZOUZI: Two things are occurring there. In the in-service capex, there is also a decrease in units to accommodate for the higher cost that was accrued due to more costly than expected spill containment, so difficult spill containment installation.

MR. RUBENSTEIN: All right. And if we go down for closers, again this one is 212 percent above your unit cost

forecast, 365 percent above your unit cost forecast and then 334 percent above your unit cost forecast.

MS. GARZOUZI: The forecasted unit cost here was low.

The structural changes were needed really in order to replace the reclosers with electronic reclosers to align with our strategy to modernize the grid and replace devices with more smarter devices where possible.

MR. RUBENSTEIN: Station refurbishments, I see, 211 percent more, 433 percent more, 209 percent more than you had forecast.

MS. GARZOUZI: This is something that we discussed at the technical conference. We talked about the fact that when we came to you last time, we talked about an IMDS which was a modular distribution station. It was quite an innovative concept at the time, and the assumption that was made was that we could build a distribution station for a million dollars.

That proved to be incorrect and therefore, the IMDS came in closer to $1.9 million and that's why you see the cost being higher. We also -- another thing occurred which is the station-centric refurbishments, which you've heard about also. So the combination of the more expensive IMDS and the station-centric refurbishment is what you're seeing. So there is -- in the station I will admit there is a lot of shifting of capital between the various categories, and it's not easy to track overtime.

MR. RUBENSTEIN: So the first part, the modular station, you thought you could do it for a certain price,

turns out it's much more expensive?

MS. GARZOUZI: I think that the assumption of 1 million was highly optimistic. From what we've seen, 1.9 million is more realistic, if we look at the transformer cost, the equipment cost, and our ability to do them. Modular stations are more cost-effective than traditional distribution stations. They just are not as cost-effective as we had anticipated.

MR. RUBENSTEIN: If we go down to the, under the lines category, pole replacements, do you see that you are doing them about 5 percent, came in about 5 percent on average, just eyeballing that, per year, correct? So you are more efficient in the pole replacement than you had forecast?

MS. GARZOUZI: That's right, so that program was 91 percent accomplished at 86 percent of the approved budget, which means that the unit price came in better than expected in that case.

MR. BOWNESS: And on that, one of the main drivers for that is our implementation of the mobile platform. That's spoken to in a number of places in here, specifically on the productivity exhibit, so pole replacement costs were possibly impacted through our mobile implementation.

MR. RUBENSTEIN: And the mobile is, everyone has an iPad, essentially.

MR. BOWNESS: A little more complex than that. It is an SAP-based solution with GIS map layers on enterprise rugged tablets, but, yes, in the same context of a mobile device.

MR. RUBENSTEIN: And then we look, and we go down, and we have got large sustaining initiatives, and that, we have 142 percent and 79 percent, and then you spent money that I didn't -- I guess didn't -- you didn't complete the work, I guess, in 2017.

Sorry, I'm looking at -- my apologies, that's PCB lines equipment replacement, 142.4 percent and 79 and then division error, since you did zero in 2017.

MS. GARZOUZI: Can you please repeat your question?

MR. RUBENSTEIN: Sure. If we look at PCB lines equipment replacement, S11. I am reading 2015, you are 142.4 percent above, 79 percent below in 2016, and then I get a division error, and that's because if you look at 2017 actuals you actually -- there is zero assets there, but you spent money. And you can't divide a number by zero, at least in Excel.

MS. GARZOUZI: If we look at the trends, so if what you're getting at is the unit price, I don't agree that it's getting worse. I think that it depends on the mix. So this is a program that addresses pole top transformers that are contaminated with PCB, and there was a pad-mounted element to this historically, so there was pad-mounted, pole-mounted. In some instances the pole is also being replaced, which could affect your unit cost, so if you consider the pole top and the pad, I don't think that there is a unit price trend that can be correlated here. I would say that it's average price.

MR. RUBENSTEIN: I wasn't making an assumption about

anything. If anything, it goes down. I'm accepting it goes down in 2016.

MS. GARZOUZI: Sorry?

MR. RUBENSTEIN: I'm just looking at -- just walking through the trend with you. It's 142 percent in 2015, in 2016 it's 79 percent, which is -- means you came in below on the unit cost basis. Then my only thing is in 2017 it appears you spent money, but you didn't do any assets, and that may be an ISA issue, I don't know.

MR. NETTLETON: So, sorry, Mr. Rubenstein, are you asking the witness --

MR. RUBENSTEIN: Do I have that correct?

MR. NETTLETON: Are you asking the witness why you spent money but there is no assets recorded in the --

MR. RUBENSTEIN: Yes.

MR. NETTLETON: -- 2017 actual column?

MR. RUBENSTEIN: Sure.

MR. NETTLETON: Okay.

MS. GARZOUZI: On the actual spend I'll get back to you at the break, on the 10.6. I'll let you know why there's a number there. It could be an ISA. I'm not sure. I can confirm.

MR. RUBENSTEIN: And last on my table we have all the information, is large sustaining initiatives, and what I see is in 2015 128 percent above on a unit cost base to 100 in 2016, 163 percent on a unit cost basis, and then in 2017, growing to 224.4 percent increase than what you forecast on a unit cost basis; do you see that?

MS. GARZOUZI: I do. The line component specifically, I wouldn't look at it as a unit cost approach. Some of them could be half a kilometre, some of them could be six kilometres in length, and so the cost and the project division is not a reflection of unit cost. What would be a better measure would be to potentially compare asset count or distance. So this does not give you a meaningful apples-to-apples comparison.

MR. RUBENSTEIN: All right. Well, what I take away from this table, and I'll put it to you, is I see that generally speaking you do the work at a higher cost than you said you were going to in the last proceeding; would you agree with that characterization?

MS. GARZOUZI: No, I don't.

MR. RUBENSTEIN: You don't?

MS. GARZOUZI: If we look at our largest capital spend, it is really the wood pole replacement program, trouble calls, joint-use programs, and when we look at those, we see a positive unit price trend or we see that we're doing a high volume of work quite efficiently.

MS. BRADLEY: The other thing I'll just add to what -- the other thing I'll add to what Ms. Garzouzi said is areas where we did see a larger variance, such as station refurbishments, there was a significant change in approach to ensure we were doing the right work while we were there instead of revisiting it later to do, like, multiple visits. So, you know, yes, the price did go up, but there was a significant change in the approach to that work which

led to a difference, and so I don't think that that's a unit cost comparison, in that it was different work.

And the other one that Ms. Garzouzi spoke about is a large sustainment initiative, which is similar in that we are going to areas that need a large project, and the reason they are characterized the way they are is they aren't repeatable, and you do have to go out and individually scope and develop each project and estimate each project. So if the work priority changed and you are going to a location with larger scope of work, it's going to be very different, so the comparison of a unit price isn't really applicable in these cases.

MR. RUBENSTEIN: So when the unit cost increases it's because the scope or the method of doing the work has changed?

MS. BRADLEY: It can be, yes.

MR. RUBENSTEIN: So in 2021 when we're back here, or 2022 when we're back here, and we're looking at the same information in this case, and the unit costs are higher, it is because your scope will have changed; is that...

MS. BRADLEY: It is not because the scope of work. I mean, in some cases the stations, I agree, it was a change in our approach in the scope of work. In other cases what I'm saying is a unit price isn't an applicable measure to measure effectiveness due to the variability in what the work could be.

MR. RUBENSTEIN: Well, then how should we measure effectiveness? If it is not unit cost and if we saw that

you've done less -- we looked at the assets. You've done much less of the assets. How should the Board and parties judge your performance over the last three years?

MR. BOWNESS: So I think there is a, you know, a key message that I want to put out here is that we recognize that the last number of years from a work execution perspective hasn't met -- I'm sorry.

So the last few years within our performance is not the performance that we anticipate going forward.

If you look at the numbers, there are could some counts that are down. If you look at the variability, we have variability in certain work programs.

If you look at some of our estimating practices, historically we would use very much just unit cost basis for stationery refurbs. We heard a lot about station refurbs from the Navigant group this morning around issues that we had with how we were managing those projects.

We made a decision back in 2015 to move the station refurb program in under the project management group that I used to run when I was on the transmission side, to bring that rigour from a project estimating and a project execution perspective.

So we very much believe that our results going forward are going to be much tighter to our plans that we have put forward. But we also have to anticipate that there is going to be variability. If you look at this past month alone, these two storms that we had where we had almost 500,000, greater than 500,000 customers impacted by storm

events, those two storms combined were $40 million of expenditure. That chewed up two-thirds of this year's storm budgets. We are having to go through a process right now around re-directing funds.

We are looking at levers that we have with worst perform feeders. We're looking at levers we have around pole replacements. We are managing within the capital envelope and this year, you know, we anticipate when we come back to present the results, we'll say storm costs are higher than budget and therefore this other element is going to be lower than budget, but we'll explain why.

What we're hopeful of over the five-year period is that some of those level out. Perhaps next year becomes a low storm year, and then we can reinvest those dollars that are saved next year to catch up on the accomplishments that we missed this year. So we do have to recognize that there is going to be some variability as we move forward, and we are also recognizing that our performance in the last period wasn't as strong as we planned to have it for the go forward period.

DR. ELSAYED: Can I interject for just one second? In your introductory remarks, Ms. Bradley, you talked about $400 million in productivity in the last five years, since the last application. What was the basis of that number?

MS. BRADLEY: That's the productivity that's incorporated into this plan.

DR. ELSAYED: Yes, I'm not sure if it is incorporated, but my note here says you mentioned $400 million in

productivity in the five years since the last application.

MS. BRADLEY: It's 400 -- I might have misspoke. It is 400 million in productivity, which is --

DR. ELSAYED: Maybe I misspoke.

MS. BRADLEY: -- in this plan.

DR. ELSAYED: Compared to the last one.

MS. BRADLEY: Which was significantly above what we had in our last application.

DR. ELSAYED: So what makes up this $400 million?

MS. BRADLEY: It's in Staff...

MR. BOWNESS: So if we could bring up Staff 123, which is -- let me just get the issue number because I think that's how we have to pull it up.

So if we pull up issue 25, Staff 123, if you scroll down a little bit, you will see the productivity initiatives that we have identified across the 2018 to '22 time period, broken down by initiative.

And down at the bottom, you will see the totals that are -- you know, for the first year, 2018, we have $36 million of capital, $30 million of OM&A, and 4 million of common. So that works out to approximately 70 million.

If you look out to the last year, you will see that that increases to about 90 million. So the average of that is 80 million times five years is the $400 million.

DR. ELSAYED: Thank you.

MR. RUBENSTEIN: Just going back to what we were discussing, if your -- based on what we talked about at the beginning, you spent -- you're seeking to put into rate

base because you spent, on the in-service basis, $122.5 million more than the Board gave you.

And, Mr. Bowness, you admit that your performance was not as it should be. Why should ratepayers have to pay for that additional amount of money you are seeking to put into rate base?

MR. BOWNESS: So the way I would position it is the difference is with respect to the estimated costs that were put forward to the Board during the last panel and the estimated volume of work that we would accomplish. And that's the comparison to the actual units and then the actual cost of what's been performed.

That's what I'm saying isn't as tight as we planned to have going forward.

I can assure you that we continue to manage and monitor costs on a project by project and program by program basis, to make sure that we're delivering a efficiently and effectively.

If I can go to your table that you have, an example that I'd like to bring forward within the cost impacts that we have that drive some of that overage is if we look at the line assayed on the screen that we have, trouble calls and storm damage.

So in the last plan, we believed that storm costs and trouble costs during the three-year period would be 58 million, 61 million, and 62 million.

If you look at our actuals of what came in, they were 16 million higher, $24 million higher and $26 million

higher. These are external events driven by weather, driven by trouble and outages that we have that we need to respond to make sure that we restore the power and ensure the lights are on in the province.

But when you balance that with a capital envelope, we have to try to manage within our means. However, that upward pressure of tens of millions of dollars does result in us coming back at times to say you know what, we were over.

The piece that I would like to put forward from a timing perspective is you brought up the comment that we were 6 percent over cumulative, over the full period of '15 and '16 and '17. We've put a lot more focus on ISA. We've put a lot more focus on redirection. We were really trying to manage within our means. And if we look at the percentage dealt over the last two years, which is the 2016 and '17 period, we were within 1.3 percent or less than 2 percent variability over that couple year period.

So there is a lot more focus and attention around managing within the envelope. 2015 is the anomalous year, $104 million within that one year, and we did explain that within VECC 28 that the two main drivers for that were external factors of joint use and relocations, as well as trouble calls and storm damage.

So it's more of an issue with respect to what was submitted of the plan versus the experience we had with the assets.

MR. RUBENSTEIN: What is -- did you say joint use and

line relocation? Is that what you said?

MR. BOWNESS: Yes.

MR. RUBENSTEIN: And that is a driver for the increased cost?

MR. BOWNESS: So maybe if we could pull up VECC 28. It is issue -- Exhibit I, tab 23, so issue 23, I guess it would be -- sorry, issue 33, VECC 28.

And you will see that in that -- oh, we're just waiting for it for a second there.

So the variance within that overall year was 105 million. But 43 million of that, a substantial amount, was with respect to joint use and relocations, which drove a variance of a $29 million change. Some of that was in your work, some of that was work that was underway and assets under construction, and was completed in 2015 to make sure that we had the work fully completed to meet the external need. As well as trouble calls and storm damage in that one year was 15 million, but as we saw from examples, that that variance carried forward into future years.

MR. RUBENSTEIN: I understand why storm damage, you've got to deal with the storms, right. I don't think you would get any disagreement.

My question is this. If the view is on all the other stuff, where your unit costs are higher than you forecast, why should the ratepayers then have to spend in addition to that? Why shouldn't that be netted out the additional amounts? You overspent, not just an things that are

reasonable, I accept, but you appear to have overspent on what you said would you do on a unit cost basis.

MR. BOWNESS: As compared to an estimated unit cost, the actual costs were higher.

MR. RUBENSTEIN: Yes.

MR. BOWNESS: I wouldn't say that we overspent. We paid for the materials, the labour, the fleet and equipment to deliver the work, and the cost of doing the work was more expensive than what we had estimated.

So what does that call upon us to do is get better at estimating, and we are continuing to invest in our systems and our processes and our reporting and our summary-level documentation so that we can have a tighter alignment between estimates and actuals going forward.

MR. RUBENSTEIN: And when the Board made its decision in the 2013-0146 and it was looking at the dollars it was going to approve versus the work you had going to do, and if you had come in with, say, more realistic estimates in your view, do you think the Board would have come necessarily to the same decision?

MR. NETTLETON: I'm objecting to that question. It calls for speculation, Mr. Chairman. I don't think it's fair to have the witnesses speculate on what the Board may or may not do if different estimates came in.

MR. RUBENSTEIN: Okay, I'll withdraw that question.

MR. BOWNESS: And I think macro-ly, going forward, another thing that has changed significantly is the focus in on the outcomes. Historically, we did focus in on the

unit production rates, which doesn't necessarily yield the best outcome. So if you look at a pole replacement unit cost, if you need to optimize and make sure you come into the OEB here and make sure that we're able to say that our unit cost numbers is bang-on, right, you may drive behaviour on looking at the less expensive poles to replace, the ones that are near the roads, the ones that have easier access, the ones that are in the better soil conditions, but what we're really focusing in on going forward is the balanced view of the outcomes, so within our scorecard going forward, you see the focus on reliability, you see the focus on customer service, right, so if we can deliver the right pole replacements and keep our unit costs in check, then -- then that's great for the customer, it's great for reliability, which is what the customer is buying, that's their product, and we're making sure we're balancing the cost that we have for unit costs.

So I think the framework and the scorecard going forward which focuses in on unit costs and focuses on the outcomes from a product perspective is going to drive the right behaviours within our company.

MR. RUBENSTEIN: All right. Maybe we can take a break.

MR. QUESNELLE: Let's take a 15-minute break. We'll return at 3:50.

--- Recess taken at 3:37 p.m.

--- On resuming at 3:55 p.m.

MR. QUESNELLE: Please be seated. Mr. Rubenstein,

please proceed.

MR. RUBENSTEIN: If you could turn to page 31, I want to correct something for the record.

I was asking about PCB line equipment replacements and noticing that the unit cost was an error. And just to be clear, the rationale for that is because there was no spending as well as no assets for 2017, so just to clarify that's why. I'd made it seem that there was some spending, and I just wanted to clarify that.

MR. QUESNELLE: Okay, thank you.

MR. RUBENSTEIN: Mr. Bowness, when we left off, you were mentioning that really the better way to look at performance is not the number of units you do, but the outcomes of the work. Did I hear that correctly?

MR. BOWNESS: I believe it's appropriate to look at all dimensions. But I think looking at the outcomes, such as reliability as well as unit costs -- as well as unit accomplishments, but we need to be looking at the big picture, yes.

MR. RUBENSTEIN: And if we could turn to page 33 of our compendium. We had asked you in this interrogatory, and I had brought this up with a previous panel as well. We had asked you based on a table in the original evidence that set out what you had -- based on the scorecard and the outcome measures you had proposed in previous proceeding, what your actuals were to those targets. Do you see that? That's what this table is showing?

MR. BOWNESS: Yes, I see that.

MR. RUBENSTEIN: I want to ask about some that would fall into this panel's bailiwick. When I see vegetation caused interruptions for 2014 to 2016, when you look at the target and the actuals, I see the outcome was worse than you had targeted, correct?

MR. BOWNESS: Yes, that's correct.

MR. RUBENSTEIN: And I see substation caused interruptions was better.

MR. BOWNESS: Yes.

MR. RUBENSTEIN: Then we go up to the next page, distribution line equipment-caused interruptions, I see worse?

MR. BOWNESS: Yes, I would agree that in 2016, it is slightly worse. But if you look at the trend between '14 and '16, there's an improving trend.

MR. RUBENSTEIN: It's worse than the target, that's what I mean by that.

MR. BOWNESS: Yes.

MR. RUBENSTEIN: And if we look at the number of replaced poles -- I know you don't have this information on this table. If we include 2017 information, and I'm getting this information from page 31 of the materials, I have that over the period of time -- and I think we had this discussion -- you replaced less poles than you had forecast?

MR. BOWNESS: We accomplished approximately 91 percent of the pole replacement program, and it was primarily driven based on the fact that we needed to redirect funds

to the CDMA external factor with the Bell shutting down the CDMA network and needing to fund that investment during that period.

MR. RUBENSTEIN: And the number of pole top transformers, you did less than you said you would. I think we had that discussion.

MR. BOWNESS: Yes.

MR. RUBENSTEIN: So of the five outcome measures from your last proceeding, four of the five you did worse.

MR. BOWNESS: So some of these I would consider to be outcome measures. A vegetation caused interruption is an outcome measure of the impact on a customer due to a tree-related outage. And as you know, we've made a very strategic shift in our vegetation management program. Substation interruptions and line equipment interruptions are outcome measures as well, but I wouldn't consider pole replacements and number of pole top transformers as outcome measures; I would consider those unit production measures.

MR. RUBENSTEIN: So of the outcome measures using your definition -- and I would tend to agree with that, I would accept that -- two of the three you did worse than you had targeted?

MR. BOWNESS: Yes.

MR. RUBENSTEIN: All right. I'd like to move on and have a discussion about your investment planning process, and I think the best way to do that is if we could start at page 9.

This is a chart or table that you provided that

outlines the process. Do you see that?

MS. BRADLEY: Yes.

MR. RUBENSTEIN: And it is a high-level outline obviously of the many steps in that process, correct?

MS. BRADLEY: Correct.

MR. RUBENSTEIN: And even simplifying this chart, I just want to explain to you what I think the process is and you can tell me if I'm right or wrong.

I'm starting at box 2.13, the needs assessment, and I understand this to be that you determine your system needs looking at those various factors and you develop candidate investments that meet those needs, and you determine the assessment of risk; do I have that correct?

MS. BRADLEY: In 2.1.3, in that part of the process, we develop a list of the asset needs. The development of solutions or the investments that will satisfy those needs is in 2.1.4.

MR. RUBENSTEIN: So in 2.1.4, you take the system needs based to follow up categories of information that you have, and then you develop candidate investments, am I correct?

MS. BRADLEY: Correct.

MR. RUBENSTEIN: And then you assess the risk of those -- doing or not doing those investments, correct?

MS. BRADLEY: We would say with the need that we have recognized, what is the risk to the system and to our customers. And then if we do an investment and we might have more than one option for how to address that need,

what is the residual risk at the end once we've done that work, yes.

MR. RUBENSTEIN: And then at a high level, you then prioritize and optimize those investments based on that information?

MS. BRADLEY: Correct.

MR. RUBENSTEIN: And with respect to need, my understanding is you are looking at a number of factors, such as customer needs, age, condition, performance of the asset, utilization, those sorts of things. That's what we're talking about asset needs?

MS. BRADLEY: Correct, we're looking at the asset itself and what needs there are with the asset, and as well as what the system needs for that asset are.

MR. RUBENSTEIN: And considering most of your proposed spending is in the system renewal category, I would assume that condition of assets is one of the most important factors in your needs assessment. Do you accept that?

MS. BRADLEY: Yes, I do.

MR. RUBENSTEIN: If we could turn to page 12 of the compendium, this is your response to AMPCO 23.

They had asked you to fill out a table looking at the condition of your assets in various asset categories over time. Do you see that?

MS. BRADLEY: Yes, I do.

MR. RUBENSTEIN: And I understand you categorize your assets into three -- the condition of you assets into three categories: high-risk, medium-risk and low-risk.

MS. BRADLEY: In here they are reflected as poor, fair and good.

MR. RUBENSTEIN: I'm sorry, I'm looking at the top. So you have also -- you have high-risk, medium-risk and low-risk, and I agree you also categorize into poor, fair and good, correct?

MS. BRADLEY: Correct.

MR. RUBENSTEIN: And when I look at this table, I see that for a number of major asset types, you don't actually have condition assessment information for them. Do you agree with that?

I'll show you an example of what I'm talking about, if you like.

MS. BRADLEY: Sure.

MR. RUBENSTEIN: If we go down to line transformers, this is all the way -- sort of the last asset category on that page.

MS. BRADLEY: Correct, yes.

MR. RUBENSTEIN: I see that you have about 515 -- in 2017, you had about 515,000 line transformers; do you see that?

MS. GARZOUZI: Yes, I just want to clarify this that table. This table was provided by AMPCO and to be populated as it was provided. So what you are seeing is a risk score.

The reason there is a lot of N/As in the table is that some assets don't have a risk score. You might have information on them, you might have condition information

on them, but it is not a risk score.

MR. RUBENSTEIN: So you have condition information on all 515,000 line transformers?

MS. GARZOUZI: No. So it depends on the asset. We could talk about various asset types, but on our lines assets especially, there is a really high volume of assets. And so we report condition by exception.

In other words, if it's good, we don't report it. If there is a problem, we collect it in the system.

MR. RUBENSTEIN: So you don't have a systematic asset condition assessment process for your 515,000 line transformers. Is that what you mean?

MS. GARZOUZI: I would say that it is not so much -- we do have a systematic approach. We do collect the data. It is -- this is more of a big data discussion. This is more about how are you reporting your data. And so this table specifically is about ACA, so completing asset condition assessments. If a transformer, a pulled-out transformer, is leaking, that would be reported in our system, but that's not an ACA. That would be reported as a defect against that transformer.

MR. RUBENSTEIN: And do you know in the total population of your line transformers what percentage of them are -- have defects?

MS. GARZOUZI: Yes.

MR. RUBENSTEIN: And that is an assessment on all of the line transformers or you just -- the ones you know that you have defects because you are out in the field doing

some work or an issue has arisen so you know that that transformer has an issue.

MS. GARZOUZI: So I'll just explain how we patrol our assets. That might help. The stations receive a more rigorous inspection. The urban stations are inspected monthly and biannually for the rural ones.

For the lines asset, we patrol our system per the distribution system code, Appendix C. Our rural assets are patrolled on a six-year cycle. Our urban assets are patrolled on a three-year cycle. Via this patrol we collect defect information on our system and we record that within our enterprise system.

MR. RUBENSTEIN: So you do know, so for example, line transformers and conductors are similar, there is -- you have a lot of N/As here for the assets. So you would know the percentage that would be -- I guess if it's a defect it's in poor condition -- you would know that information, so there is a number somewhere in Hydro --

MS. GARZOUZI: It's more -- it's more that we don't categorize it in high, medium, low risk, right, so this question is about how risky is that asset, right, how likely is it to fail based on information that you have, and so based on the ACA view this table is completed and is correct. However, if I see a frayed conductor while I'm patrolling, I would report that this span of the conductor is frayed, and that would be then reported, and it would be actioned as a defect.

And so it's not that -- we don't view it as 1 percent

of my conductor's high, medium, or low risk, we would then just treat that as a defect.

MR. RUBENSTEIN: Wouldn't you want to know what percentage of your transformers are in high risk, medium risk, low risk, or poor, fair, good, depending on which classification?

MS. GARZOUZI: A pole top transformer's -- it is quite common in the industry that they are run to failure assets, and I think that reporting by exception, so in other words reporting when there is a problem, if it has PCB contamination or it's leaking, I think that it's appropriate.

MR. RUBENSTEIN: Okay. If we turn now to page 15, this is from AMPCO 24, and they ask you to fill out another similar table with respect to asset failures; do you see that?

MS. GARZOUZI: Yes.

MR. RUBENSTEIN: What I see is a lot of parts that you couldn't fill out, correct?

MS. GARZOUZI: Correct.

MR. RUBENSTEIN: And just using the conversation we were just having with respect to line transformers, which you said you were running them to fail, I look -- you have note 4 and note 5. Sorry, note 5 for that. And you say you don't track failures at this level of granularity. So you don't track how many line transformers fail; do I have that correct?

MS. GARZOUZI: I think there is two things. There is,

how do we report reliability, right, so what granularity is your reliability information being reported at, and the other thing is, how are you collecting your data and how are you grouping your data from an asset condition assessment perspective.

So specifically for pole tops, from a -- did it contribute from a reliability perspective, that granularity we reported as a line component failure, but if there is a defect from a patrol perspective, we would capture that.

MR. RUBENSTEIN: So you -- as I understood what we just talked about before, for something like line transformers, you wouldn't track the condition on an asset condition assessment basis because you are running them to fail, but here I see you don't even track how many you are failing.

It seems like you would -- if you don't do the first, you need the second set of information. Do I have that correct?

MS. BRADLEY: I don't think the first part was characterized properly. We don't -- when we do our line inspections we don't ask the staff that are out doing that inspection to report everything that's good. We ask them to inspect the problems that they see as a defect so that we can then plan to go back and fix it before it fails, but we don't ask them to input the millions of assets that are out there that, yes, this is good, yes, this is good. Like, on one pole I believe there's eight characteristics about a pole that they could report a defect on, but we

don't ask them to say it's good. We just ask them to say when it's in poor shape. Then we can initiate the action to go and fix it.

So I wouldn't say that we don't track -- we don't track condition information in that if it's leaking you go and fix it. You don't -- or replace it. You don't have to monitor ten different characteristics and put them into an algorithm to tell you its condition.

On the failures, in the past we've just said this is a line equipment failure. I think there is the potential to change that going forward with those tablets that you like, you know, it will be much easier the line staff are out repairing something that is trouble, it will be much easier for them to categorize which piece was fixed as a result of a storm, for example, when you have many, many things you are fixing, it will be much more easy going forward to characterize what the actual failure mode was, what the device was.

MR. RUBENSTEIN: So you said, well, we don't go for a pole -- I think what I heard you say, we know for a pole there's eight different things that we could mark a defect. We don't do -- we don't say if they're good or poor or fair. did I understand that correctly? You used the pole example specifically.

MS. BRADLEY: When we go out -- so poles are slightly different, in that we do a pole test, so I might have used the wrong asset, sorry. I'm just, I was getting around how many pieces of data we do have in our system.

With a pole they do some testing and they input whether it's in poor shape -- condition.

MR. RUBENSTEIN: Okay. So -- but if we take a look at line transformers as an example. I know you say you categorize them as well as others in the other line components category, but going forward you're budgeting how many line transformers you need to replace, and if you are running them to fail, shouldn't you know how many are failing historically? Seems like that's a key piece of data one would want.

MS. GARZOUZI: So the way that the component -- so the pole top transformer is tracked, it is actually done under trouble, and the way the trouble program is forecasted is based on historical average, and so we use that to forecast the future.

MR. RUBENSTEIN: So it is based on total spending in the category of trouble calls or not -- what we think is going to need to be -- we have on hand what --

MS. GARZOUZI: For trouble calls it is forecasted based on historical trends.

MS. ANDERSON: Sorry, trends in what? In dollars or number of units?

MR. BOWNESS: So trouble is based on dollars. We use dollars as the proxy for the amount of work. As Ms. Bradley mentioned, we are looking to get more granular information as we are doing storm and trouble response using the tablets. We went live just a year ago. We focused in on plant work that we have, new connects, pole

replacements, and such we are using for data line patrols, and we are currently making sure that our line staff start to use it to capture better information when we are in storm and trouble situations to be able to feed better information back to our asset planners.

But when we look at our storm and trouble forecasting process for future years we are using historical averages as to what we've seen, and then we are looking at, with programs like vegetation management that have a goal of driving 6- to $12 million of cost reductions in the trouble space, we will be looking to forecast those volume -- dollar volumes down in future hearings -- submissions.

MR. RUBENSTEIN: And am I correct that with respect to how your asset strategy, with the exception of vegetation management, there have been no changes since the last proceeding? And I'm looking at page 16 of the compendium. We asked you, has Hydro One's asset strategy changed since EB-2013-0416 application? If so, please explain the changes. And you say --

MS. GARZOUZI: That's correct. The nuance would be the station discussion that we had, so the station centric approach which was documented in the pre-filed evidence.

MR. RUBENSTEIN: Now I'm back at page 9 on the chart there.

As I understand what you do in the optimization process -- and I think you briefly discussed this -- is you assigned a baseline risk level for each investment project or program, and then you assign what is a residual risk, so

if you do the project, what is the change in risk from the baseline. Do I have that correct?

MS. BRADLEY: If you do the investment, what is the change in risk? That's the process, to assess different options, to asses the risk, and we pick the one that adds the most value.

MR. RUBENSTEIN: And the risk level, as I understand it, is based on a composite of a number of different individual risks that are mapped to your strategic objectives, correct?

MS. BRADLEY: Correct.

MR. RUBENSTEIN: And if we turn to page 44 of the compendium, this is that -- these are the weighting and the criteria, correct?

MS. BRADLEY: Correct.

MR. RUBENSTEIN: So for an example, you've weighted customer at 17 percent?

MS. BRADLEY: Yes.

MR. RUBENSTEIN: And you have a separate one for reliability at 13 percent; do I have that correct?

MS. BRADLEY: Yes.

MR. RUBENSTEIN: So can you help me understand what the separation is between customer and reliability? One would assume that customers value reliability. What's the difference between the two and are there overlapping elements to those risks?

MS. BRADLEY: For reliability, we'd be looking at -- the way this is used in the optimization is if one

investment option, one investment would impact a larger number of customers, for example, and have a bigger impact on reliability overall, that would have a higher score in the reliability category.

In customer, it's primarily used to drive -- you know, there could be specific needs or outcomes of customers, say around power quality. It could be that customers are looking to connect to the system. That would be a customer risk that you are mitigating that we have to connect that customer, so we would have use that category of customer.

There are investments that are required for communicating with our customers, or billing is a customer aspect to it. So there are a number of non-reliability factors in that customer risk factor.

MR. RUBENSTEIN: And I see that you have employees, 9 percent. Do you see that?

MS. BRADLEY: I do.

MR. RUBENSTEIN: And the business objective that is mapping to is achieve and maintain employee engagement.

What kind of a work program would involve achieving and maintaining employee engagement in your business?

MS. BRADLEY: Actually, Mr. Jesus might be able to help. I can't think of any investments where in my business we've use the employee engagement risk factor.

It could be in, say, an IT investment or something like that. But in planning for assets, like whether it's renewal or development, we don't.

It's in this table as this is one of the Hydro One

business objectives and we've worked to be inclusive and ensure that we're weighing all our of our investments against the objectives that the company believed were important.

MR. JESUS: That's confirmed from an IT point of view or from an HR point of view. We would weight those investments looking at the employees and the employee engagement and the risk that they pose.

MR. RUBENSTEIN: Okay. Now, I see financial benefit, 13 percent; do you see that?

MS. BRADLEY: I do.

MR. RUBENSTEIN: And I also see shareholder value, 9 percent; do you see that?

MS. BRADLEY: I do.

MR. RUBENSTEIN: What exactly is the difference between financial benefit where I see the business objective is achieving ROE and the shareholder benefit, which one would assume is that?

MR. JESUS: So the financial benefits are the benefits associated with an investment that's undertaken. So for example, if you are doing an IT project, you want a payback and a return on that investment. So you would identify what those benefits are in order for that project to proceed.

From a shareholder value, it's more about what the reputation -- how it would impact reputation, media attention, whether or not -- so those kind of factors are what's driving the shareholder value.

MS. BRADLEY: The other thing that we use as an example that's a bit more concrete under shareholder value is ensure compliance with all codes, standards and regulations. So while there is a reliability risk and potentially a financial risk associated with not meeting the codes and regulations that we're required to meet, there also is that sort of shareholder value or the reputational risk, if you are found to be non-compliant with something. We really avoid that based on all factors.

MR. RUBENSTEIN: If we can turn up Energy Probe 26 -- and I apologize, I don't have that in the compendium -- and that's under issue 25.

MR. BOWNESS: It's I22.

MR. RUBENSTEIN: I25 Energy Probe 36.

MR. JESUS: I22, Energy Probe 26.

MR. RUBENSTEIN: You have it. The one up on the screen is correct.

And you mention in part A that there were some changes made to the weighting in 2015; do you see that? Do I have that correct?

MS. BRADLEY: Yes, do you.

MR. RUBENSTEIN: And you say, for example:

> "Hydro One's management reassessed the weighting in 2015 to reflect Hydro One's desire to improve outcomes-based factor for customer satisfaction. This resulted in the weighting assigned to the business driver customer focus being increased to 20 percent. There is also a reduction weight

given to reliability from 20 to 15 percent."

Do you see that?

MR. JESUS: Yes.

MR. RUBENSTEIN: If we turn to page 45, this was a technical conference undertaking from the previous proceedings where you provided the weights in that at the time. Do you see that? Do you have that?

MR. JESUS: Yes, I do.

MR. NETTLETON: Sorry, Mr. Rubenstein, you said this was an undertaking from --

MR. RUBENSTEIN: The last proceeding.

MR. NETTLETON: -- the last proceeding. So this is evidence that hasn't been filed in this proceeding?

MR. RUBENSTEIN: Well, I provided it to my friends yesterday morning, following the 24-hour rule.

MR. NETTLETON: It wasn't included in the compendium you gave to me this morning, or this afternoon.

MR. RUBENSTEIN: It's page 45 of the compendium, so it's in that.

MR. NETTLETON: Which was given to me this morning.

MR. RUBENSTEIN: I sent the document to Hydro One yesterday morning in furtherance of the 24-hour rule.

MR. QUESNELLE: I think that's acceptable, Mr. Nettleton.

MR. NETTLETON: Absolutely, if it was. But I only received this today.

MR. RUBENSTEIN: I'm almost certain I sent a number of documents yesterday morning before the hearing began. All

right. Well...

MR. NETTLETON: Witnesses, have you seen this document?

MS. GARZOUZI: Well, we have it in front of us now. It's on page 45.

MR. QUESNELLE: The point is did you receive it yesterday morning?

MR. RUBENSTEIN: I didn't send it to the witnesses. I don't know their -- I sent it to Hydro One's team.

MR. NETTLETON: Maybe if we could pause and let the witnesses take a look at it before, because again, I have -- I was led to believe that all of the compendium documents were materials that had been previously filed on this record. So that there was no --

MR. QUESNELLE: New information in the compendium.

MR. NETTLETON: -- surprises.

MR. QUESNELLE: Well, I don't know what Mr. Rubenstein's cover note said, but you did identify it in your opening remarks that there were also filings from the previous application.

MS. BRADLEY: It was with something that we did receive yesterday. There was about 500 pages of stuff, and it was in there.

MR. RUBENSTEIN: It was with the table that you said the contents were okay, so I assumed it was okay. Not a whole amount is turning on this. I just want to just -- so if we look at it TCJ, this was, as I understand it, the weightings that were -- the similar weightings that were

just simply in the other proceeding. Is that your understanding of that as well?

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

MR. RUBENSTEIN: As I understand this technical conference undertaking, it was the risk weightings that you provided, at least in that proceeding. And as you said in Energy Probe 36, there were changes made in 2015, and we have the new weightings.

MS. BRADLEY: That's what this appears to be, yes.

MR. JESUS: Yes.

MR. RUBENSTEIN: Okay. And in Energy Probe 36, you said that with respect to the changes you made this results in weighting assigned to business driver customer focus for being increased to 20 percent. This was a reduction given to the reliability from 20 to 15 percent. I think we talked about that.

And what I see was customer was 15 percent in the EB-2013-0416 proceeding; do you see that?

MR. JESUS: Yes, I do.

MR. RUBENSTEIN: And if we flip back to page 44, I see customer now being 17 percent, not 20 percent; do I have that correct?

MR. JESUS: So from a risk weighting point of view the same risk factors -- you see customer weighted at 20 percent, and as explained there the CFO and the CEO reviewed these prior to this proceeding in May, and they wanted to put in a greater emphasis on customer. This was back in 2015, sorry.

So when you add the financial benefits, which has always been prevalent, the risk weightings are changed, so you are basically looking at normalizing it on a scale of 1 to 100. That's why you have the discrepancy.

MR. RUBENSTEIN: Yes, and I just -- as I understand, it was 15 percent in the last proceeding and it is 17 percent now. Do I have that correct?

MS. BRADLEY: Mr. Rubenstein, I think the confusion is in the Energy Probe document.

MR. RUBENSTEIN: Um-hmm.

MS. BRADLEY: It states that reliability was given a -- reliability weighting was moved from 20 percent to 15 percent, and I think that was intended to say points.

If you look at the table in section B1-1-1, DSP section 2.1 on page 27 or on page 44 of your compendium, you will see that the customer points are 20 percent and the weighting is 17 percent. So there was an error in -- the total points is 115 points, so that was an error in this response.

MR. RUBENSTEIN: Okay. So then confirming then, if we are talking about percentages, not points, you moved customer from 15 percent to 17 percent; correct?

MS. BRADLEY: That would be correct.

MR. JESUS: Sorry, I think even in the last proceeding the benefits portion would always be there, so we need to look at whether or not it would have adjusted it as well. And I don't know the answer to that.

So right now when we add the financial benefits in

there that's -- it's obviously skewing the overall weighting of that particular factor. I just don't know whether or not in the previous proceeding the same thing had occurred, whether they left it out intentionally. I can't tell you that.

MR. RUBENSTEIN: Okay. Well, I'd like to -- well, I'm trying to understand what has changed, and obviously the evidence shows there is a change, and I understand what you are saying. You weren't there in that proceeding. Is there some way that we could find out? I just want to make sure we are comparing apples to apples when I look at TCJ1.21 from the previous proceeding in this proceeding.

MR. JESUS: I would suggest to you that it is very likely that they are the same, subject to check, that there is an economic benefit even in the previous rate filing that would have been tacked on similar to what we did in the DSP.

MR. RUBENSTEIN: All right. Well, say -- okay. So then we should -- we should not consider the financial benefit and just look at the weight -- the weighting points instead of the percentage if I wanted to do -- we assume that you're correct -- that's the best way to look at the comparison?

MR. JESUS: Which would make them identical, effectively, from a customer point of view.

MR. RUBENSTEIN: If we go to page 45, shareholder value is at 5 percent. Do you see that? And now it's 10 percent? It is ten points, so it's gone up five points or

percentages; do I have that correct?

MR. JESUS: It has gone up five points, yes.

MR. RUBENSTEIN: Why is that appropriate from a customer perspective? How many customers benefit from that?

MS. BRADLEY: I think in ensuring compliance with code standards and regulations it is important to our customers. It is ensuring that the value of the company is maintained. It is consistent with the renewed regulatory framework. It does talk about sustainability of the company and financial performance, so this is looking at ensuring that we are meeting the codes and regulations and that it doesn't negatively impact -- it would be both our customers and the company.

MR. RUBENSTEIN: If you could turn to page 17 of the compendium. This is the response to AMPCO number 1, and I apologize, I've accidentally only included page 2. I'm not sure what happened in the compendium.

So you may want to -- if you are more comfortable, we could put up the -- the folders could be put up on the screen, but as I understand what this table, the table in part B and C, is showing, is it's providing at each stage of the investment planning process the number of candidate investments and the expenditures in each of those years at each of the different stages; do I have that correct?

MR. JESUS: That's correct.

MR. RUBENSTEIN: Now, if we moved to page 19 of the compendium -- this is JT3.7 -- you broke it out into the

various categories, the access, renewal service, general plant; do you see that? And OM&A; do you see that?

MR. JESUS: Sorry, what page on the compendium now?

MR. RUBENSTEIN: Page 19.

MR. JESUS: Okay.

MR. RUBENSTEIN: And am I correct where the chart says O&M, it is really OM&A?

MR. JESUS: That's correct.

MR. RUBENSTEIN: So it is not simply operations and maintenance expenditures, it's all the operations and maintenance and administration costs, shared services?

MR. JESUS: That's correct.

MR. RUBENSTEIN: Now, does your system optimize O&M costs in addition to capital costs? So if we go back to the previous page where we had candidate investments at each stage on page 17, is that simply capital work or does that include OM&A work?

MR. JESUS: It includes both.

MR. RUBENSTEIN: SO if we are looking at JT3.7, if I look at the capital, what I see is -- I'm sort of flipping back between the two -- what I see is in the first stage the investment development. Is that when people input the various candidate investments into the system?

MR. JESUS: That's correct.

MR. RUBENSTEIN: And so there were 393 candidate investments, correct?

MR. JESUS: Yes.

MR. RUBENSTEIN: And the total capital cost I get on

JT3.7 for that is about $4.1-billion over the five years? Do you see that, or would you take that subject to check?

MR. JESUS: 4.1-billion?

MR. RUBENSTEIN: You're right, does not -- yes, 4.1-billion. Would you take that subject to check?

MR. JESUS: No, because if I just add the 1s, I am at more than $5 billion --

MR. RUBENSTEIN: Just talking about capital.

MR. JESUS: Oh, just looking at capital?

MR. RUBENSTEIN: Yes.

MR. JESUS: Okay, subject to check.

MR. RUBENSTEIN: Okay. Now, as I understand the optimization process, how it works is you have a system, I believe it is the Cloverfield system?

MR. JESUS: I'm sorry?

MR. RUBENSTEIN: You have --

MR. JESUS: Copperleaf?

MR. RUBENSTEIN: Did I say Cloverleaf -- I'm not sure what that is. Salmon, I think. Copperfield. You have the Copperfield system and you have put in the various -- it's late in the day --

MR. JESUS: Copperleaf --

MR. BOWNESS: Copperleaf is the product vendor.

MR. RUBENSTEIN: Thank you, you put them in your system, just refer to it as the system, with the various -- the baseline and the residual risk, correct, that we talked about?

MR. JESUS: Yes.

MR. RUBENSTEIN: And as I understand, also what you do is for certain programs or projects you put in various levels of spending and -- in the work you would do, correct? These are the alternatives? The --

MR. JESUS: Yes, there would be a vulnerable level, there would be an intermediate level, there would be an as optimal level, there would be number of levels that planners would input.

MR. RUBENSTEIN: So this is what you are talking about at page 23? This is an excerpt from one of the presentations. That's what you are talking about.

So you would put in an asset optimal level with the cost and the units you would be working on, intermediate level, obviously less cost, less assets and the vulnerable level, correct?

MR. JESUS: Yes.

MR. RUBENSTEIN: And so when it optimizes, am I correct that it is only optimizing -- it could can only choose one of those three options for a program, correct?

MR. JESUS: That's correct.

MR. RUBENSTEIN: So if you have, say for example, poles in the asset optimal, you are going to do 16,000 poles at a cost, intermediate you are going to do 12,000 poles at less cost, slightly less cost, vulnerable at 10,000 poles at less -- it can only optimize between those three alternatives, correct?

MR. JESUS: That's correct.

MR. RUBENSTEIN: How are you determining what the

levels are for those alternativ4es?

MR. JESUS: We're determining the levels based on the risk that is present on the system. So a good example would be to look at the number of poles that are in poor condition, and if you were to have 107,000 or 106,000 poles that are in poor condition and they're fairly old, they are at end of life and they're looking -- they are probably going to fail, very likely that they are going to fail within the next 5 to 10 years, then -- let's assume that they fail over the next five years, there is a 50 percent probability of failure.

So you take the 109,000 and you multiply the 50 percent that it's going to fail over the next six years, and then you would look at the impact. From a consequence point of view, what's going to be the impact to our customers.

Let's assume for all intents and purposes, every time a pole fails there is a customer interruption of about 200 minutes. So from a customer minutes of interruption, you would look at all of that, you would aggregate all the poles that you are replacing in each one of the vulnerable levels, you would add them up, you would go to table I24, Staff 89, and in the appendix there. And if you look at it from a reliability point of view, depending on the number of customer interruptions -- so let's assume that from a -- the vulnerable level that we're going to have 500 to -- 500,000 customer minutes of interruption, you would actually pick that particular box.

And the likelihood on a probability scale, if you continue to scroll down, you would pick what is the likelihood of that particular pole or that group of poles failing within the next five years.

So based on that assessment, we categorize the high risk poles, the lower risk poles, we're putting them into those buckets and each one of them would have a level of risk that the planners would then go in and say this is the risk that we're mitigating. The more money you spend, the more risk you're mitigating. So that's the process that they follow.

MR. RUBENSTEIN: I fully understand that, obviously, the different levels of the engaged risk. But if you only have sort of three options, right, the system doesn't -- as I understand it, doesn't optimize 16,000 poles, you are doing 10,000 poles, you are doing 8,000 poles. You can't pick somewhere in between based on risk levels that would obviously occur.

MR. JESUS: Right.

MR. RUBENSTEIN: How are you determining that intermediate is 10,000 poles?

MR. JESUS: So the optimizer would look at the value, total risk it's mitigating and the total value that it's delivering in terms of selecting the proper option.

MR. RUBENSTEIN: I understand that that's how the system work works. You -- a planner who is inputting has to pick one for asset optimal, has to pick one set of poles and the cost for intermediate, and one for vulnerable.

How do you determine what the intermediate is, or what the Vulnerable is?

MR. JESUS: Because just as you have shown on page 23 of your compendium, there's increasing risk that you are mitigating with each level of spend. You are doing more poles and you are mitigating more risk, and so the planner would go in and enter all of those poles.

So obviously there is 106,000 bad poles that we have on the system. He's not going to -- he's going to be focused in on those poor condition poles. He's not going to be focused in on the remaining 1.5 million poles, if that's where you are going, because it doesn't make any sense to do that. Those poles are not in poor condition. We are not going to enter the risk for those remaining 1.5 million poles.

MR. RUBENSTEIN: If intermediate sits between asset optimal and vulnerable, I assume intermediate means compared to asset optimal. You are spending less money, you are doing less work, but obviously the risk is going to be higher than asset optimal.

MR. JESUS: Right, and each one of the vulnerables -- the actual definition of vulnerable is that we are in the red zone and that risk is deteriorating. There is additional risk and in fact, the performance will deteriorate.

The asset optimal is about maintaining. So effectively, we're maintaining the reliability, we're maintaining that level of risk.

In asset optimal means we're actually improving that particular risk, and for poles we're effectively at asset optimal is the selection where we landed on.

MS. BRADLEY: Mr. Rubenstein, I might be able to help a little bit based on --

MR. RUBENSTEIN: You can, but I do now understand, I think the last part explained it. But you can continue.

MS. BRADLEY: One of the recommendations from the benchmarking study we did recently was around planning, in a centralized manner, poles in a more granular -- like for more of the program, having that pole program planned in planning instead of in the field.

So one of the things that we have implemented or are implementing going forward -- I think for 2018, we've done this -- is breaking down poles by their risk to come up with different levels. So one, we're not restricted to three levels, but all of our poles have been categorized according to the risk that they mitigate when we replace them, or the risk associated with that pole.

So poles in areas where there's large numbers of customers and if that pole was to fail, they would take out tens of thousands of customers, are in one category, where poles that are in locations where they would take out hundreds of customers from a reliability perspective would be in another category.

So to enable us to release specific bundles of work where it's going to mitigate the most risk for our customers, you know, that segregation has taken place going

forward based on the recommendation from that benchmarking study.

So we won't be limited to three. We would have as many as we saw fit to come up with meaningful bundles of reliability-based pole replacements going forward.

MR. RUBENSTEIN: If I could take you to page 22 of the compendium's response to AMPCO 36 part E, in my understanding of what the table is showing that over the different planning cycles, what the amount of the candidate investments you can actually optimize, correct?

It's on page 22 of the compendium.

MR. JESUS: Okay, continue on. Yes, I'm there.

MR. RUBENSTEIN: Am I correct that what the optimized portion of the plan in the table is showing is for the different planning cycles, what percentage of the candidate assessments or the dollars that make up the program -- not sure which one -- can be optimized. Do I have that correct?

MR. JESUS: That's correct.

MR. RUBENSTEIN: And when it's not optimized, that means the program says you are going to do it. Do I understand that?

MR. JESUS: That's correct, and so when we say we are going to do it, it's largely due to compliance or other rules and regulations that we need to comply with. So there is not a lot of flexibility there. We need to respond to storms, we need to respond to the ESA, we need to do all of that work. So that's must-do work.

MR. RUBENSTEIN: And I would assume more optimization, the greater percentage of the program that can be optimizable is preferred. Would you agree with that?

MS. BRADLEY: I would agree with that. We are trying to get that more investments are input that we can optimize to pick the most value.

MR. RUBENSTEIN: So when I look at the table I have for 2016 to 2010, I assume that means it's a typo and it's 2021. Do I have that -- is that correct?

MS. BRADLEY: Sorry, can you repeat that?

MR. RUBENSTEIN: It says the first is 2016 to 2010 cycle. I assume that should be 2021 cycle, correct?

MR. JESUS: That's correct.

MR. RUBENSTEIN: So that's 32 percent. Then I see the 2017 to 2022, it's actually at 23 percent. So it's dropped. Do you see that?

MS. BRADLEY: I do.

MR. RUBENSTEIN: And this distribution system plan, is it based on the 2017-2022 cycle?

MR. JESUS: Yes, it is.

MR. RUBENSTEIN: So it's actually dropped. And then we have a big increase in 2018 to 2023; do you see that?

MS. BRADLEY: I do.

MR. RUBENSTEIN: What's driving the very significant increase over that one cycle?

MS. BRADLEY: I would say that it's leadership direction. We've had a change in the leadership team and have really pushed to challenge, for every investment

people put in as non-optimizable, what's the document or the proof that we have no choice and what's the level of flexibility that we can really get to? We might say, you know, it's required because of spills, and this -- you know, we need to do this, and we've really challenged what are other options, what are other ways to do this, and do we have really firm supporting documentation to support you saying it's -- there is no option.

MR. RUBENSTEIN: So you're doing it better now, I guess; is that fair?

MS. BRADLEY: I think we're being more -- more prescriptive in how people put things as a required.

MR. RUBENSTEIN: More accurate; is that fair?

MS. BRADLEY: That's fair.

MR. RUBENSTEIN: So if it's preferable to have the higher percentage of your plan optimizable and the plan that you are putting forward in this proceeding is based on -- is lower than both the previous plan and about a third of the one that's being in place for 2018, 2023, how can the Board have proper comfort that your plan is proper?

MS. BRADLEY: I wouldn't say that a plan -- when somebody says it's not optimizable or it is optimizable, it doesn't mean that there isn't a need that exists. You know, something could be in poor condition and you can still optimize and do it when it fails or do it proactively, for example.

So it doesn't -- it doesn't negate that there is a need to act; it is just, our preference is for people to

let the optimizer pick the optimal work program.

MR. RUBENSTEIN: I'm not sure how long the Board wants to continue. I can stop now or go for another ten minutes or...

MR. QUESNELLE: If you have a natural break in your -- we can go a little longer if you've still got more in this area.

MR. RUBENSTEIN: It would be preferable. I just want too finish off this section.

MR. QUESNELLE: Sure, okay. Yeah.

MR. RUBENSTEIN: If we can turn to page 17, back to page 17, so this is the -- back to the different stages in the process.

So I take it the investment optimization stage, you've now run -- you press "optimize" in the program and it spits out based on the criteria a set of -- a capital plan for the 2018 to 2022 period, correct? That's where we are at that stage, at a high level.

MR. JESUS: So the optimization was run, correct, yes.

MR. RUBENSTEIN: What are the constraints you put on the program? Is it a cost constraint? Is it a risk constraint? Is it a reliability constraint? What's the constraint that you put on the system?

MR. JESUS: So there are financial constraints that we applied, and they are in one of the interrogatories, but effectively they are financial constraints that are in the system that we would -- that we would enter for each year.

MR. RUBENSTEIN: So we get to the investment

optimization stage, and then we move to the investment approval and implementation stage, correct?

MR. JESUS: That's correct.

MR. RUBENSTEIN: And between the investment -- development and optimization I see less money is being spent and I see less candidate investments, correct, at that stage, you've reduced it, correct?

MR. JESUS: So in going from --

MR. RUBENSTEIN: Investment development to investment optimization.

MR. JESUS: We dropped -- basically we reduced the total levels by close to $717 million in going through the optimization, yes.

MR. RUBENSTEIN: But then at the investment approval implementation stage you are adding candidate investments and the dollars go up.

Can you help explain to me what happened there?

MR. JESUS: Sure, so there were a number of -- so there were a number of projects that were currently in execution, so what we did was we looked at the projects that had been deferred from -- from '17, from the previous year, that had not been completed, and we accounted for those dollars, as well as, there were some IT changes that occurred, and the -- from a -- from a security point of view, from an IT implementation, those costs and those investments were included.

MR. RUBENSTEIN: And do you -- why wouldn't you then -- it seems to me what you are saying, the reasons why

you added that, you wouldn't have just changed the inputs for those investments and then rerun the optimization using the same constraints? Why do you just sort of add it afterwards?

MR. JESUS: So that's a meeting with the business that basically we have the discussion and we have an enterprise -- as part of the enterprise engagement that we are carrying out with the business, and they've effectively changed the IT strategy, so there is a mix of investments that are coming into play that would then be included because, again, they need to be carried out.

MR. RUBENSTEIN: So it is just a timing thing?

MR. JESUS: It is a timing issue.

MR. RUBENSTEIN: All right. We could break. Thank you.

MR. QUESNELLE: Yeah, we just have a question from Mr. Elsayed.

DR. ELSAYED: I just want to understand the term "optimization" as you use it. We talked about probability, consequences, and risk. You look at different investments, you look at the risk associated with each. How do you draw the line to say this is an optimum plan?

MR. JESUS: So drawing the financial budget is characterized based on the previous OEB ruling, so we would have looked at the previous plan, the decisions that the OEB have dictated and provided to us, that would be used to inform the line.

The other piece, the other big piece, is the customer

engagement that we carry out, so we've had a huge process that took all of our customer needs and preferences into account, and customers told us resoundingly that cost is an issue, but we need to balance the rate impacts, we need to balance the condition in the asset needs, as well as the customer needs and preferences.

So at the end of the day we need to make sure that the assets are in good working order, so there is a lot of competing elements that will drive how we draw that budget line. And in this particular business DSP before you we actually have Plan A, B, and Plan B modified, where we basically said, you know, we were recommending Plan A because we thought we needed to do -- we absolutely needed to do all of these investments because there truly is a lot more investment on the system that needs to occur because the system is aging, so the senior management came back to us and said, No, go back and come back with B modified, so that's how we drew the line. That's how we arrived at the line that we did.

DR. ELSAYED: So you mentioned customer input and you mentioned OEB rulings. I'm just trying to understand where risk comes in. How much risk tolerance are you building into this plan? How do you determine that?

MR. JESUS: Right. So the risk --

DR. ELSAYED: What's the liability for it?

MR. JESUS: Exactly. So the chart that I will take you again is Staff 29, back to that risk chart, and for each one of those investments planners are picking,

selecting, the preferred investment, identifying what the baseline risk is, and then what the investment required to mitigate that risk, and what's the cost of -- what's the remedial risk or the residual risk left on the system.

So the optimizer looks at that and it shifts the investments as much as possible and it comes up with the most optimum plan, is how it does that, and it is selecting the highest risk investments.

So in the first candidate development plan we had 310 projects with additional $717 million that potentially were in the system and that we eliminated because of the risk --

MR. BOWNESS: So it might be helpful just to look at the liability and the risk scorecard and maybe give an example of what is low and medium and a high risk. It's just really small font on the screen, so it might be helpful to show an example.

MR. JESUS: So again, from a green -- green has been categorized into five different categories, minor 1 to minor 5 risk, from a consequence point of view, and that's because each individual pole in itself is not going to have a huge risk. But when you aggregate 100,000 poles the risk starts accumulating, and when we look at it from a reliability point of view you will see that if we go to reliability -- this one? There. So from a reliability point of view we are looking at the duration of distribution outages and the impact to customers. So basically from the customer they would actually calculate what the impact is and they would select the proper box.

They would do that for each one of these categories. So they would do it for reliability, they would do it for customer, how many customers we're impacting, whether they're critical customers that we're going to be impacting, and again they would pick the proper box.

And we aggregate customer risk, the reliability risk, the environmental risk, the shareholder risk, weighted as we talked about earlier, and we end one a total risk value that the planners would then input.

MS. BRADLEY: To help for one second, you asked how we draw the line and one of the factors that relates to this table is we hold -- Bruno actually holds a workshop with the executives where we talk about which one of these risks, save for reliability, are we okay with.

So where would you never invest to fix this problem? And, you know, where would you always invest to fix this problem, almost like a -- you know, we would never want this situation to exist on our system, and we do that for all the risk factors.

So part of drawing the line is saying all of the risk that is we said we would never invest -- we would never not invest to fix this, it has to be remediated. All of those contribute to, you know, where's the line of your minimum spend. We don't want any of those red risks to remain on the system.

So that process is a process that we do regularly with the executives to say, you know, what level of risk tolerance do we have as a company, and that helps inform

where the overall funding line is when it comes to asset risk.

MR. ELSAYED: Thank you.

MR. QUESNELLE: Thank you very much. We'll resume on Thursday morning at 9:30 with this panel and continuing with Mr. Rubenstein. Thank you.

--- Whereupon the hearing adjourned at 4:57 p.m.