ONTARIO ENERGY BOARD

FILE NO.: **EB-2010-0379**

Empirical Work in Support of Incentive Rate Setting in Ontario for Electricity Distributors
Stakeholder Conference

VOLUME: **3**

DATE: **September 11, 2013**

EB 2010-0379

THE ONTARIO ENERGY BOARD

EMPIRICAL WORK IN SUPPORT OF INCENTIVE RATE SETTING IN ONTARIO FOR ELECTRICITY DISTRIBUTORS
STAKEHOLDER CONFERENCE

Held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Wednesday, September 11th, 2013,
commencing at 9:34 a.m.

A P P E A R A N C E S

CYNTHIA CHAPLIN	Board Member and Vice-Chair
PAULA CONBOY MARIKA HARE ALLISON DUFF CHRISTINE LONG	Board Members
BRIAN HEWSON LISA BRICKENDEN	Board Staff

PRESENTERS:

FRANK CRONIN	Power Workers' Union (PWU)
ADONIS YATCHEW	Electricity Distributors Association (EDA)
STEVE FENRICK	Coalition of Large Distributors (CLD)
JAY SHEPHERD	School Energy Coalition (SEC)

ALSO PRESENT:

LARRY KAUFMANN	Pacific Economics Group (PEG)
BRUCE BACON	Borden Ladner Gervais
GORD EAMER	CHEC Association
JULIE GIRVAN	Consumers Council of Canada
DAVE PROCTOR	Cornerstone Hydroelectric Project
MAURICE TUCCI	Electricity Distributors Association (EDA)
DAVID MacINTOSH LARRY SCHWARTZ	Energy Probe Research Foundation
GIA DeJULIO	Enersource Hydro Mississauga

A P P E A R A N C E S

DAVID FERGUSON	Entegrus Powerlines
MICHELLE SOUCIE	Essex Powerlines
TRACY REHBERG-RAWLINGSON	Halton Hills Hydro
JAMIE GRIBBON	Horizon Utilities
CARM ALTOMARE MAXINE COOPER	Hydro One Networks Inc. (HONI)
JANE SCOTT	Hydro Ottawa
LAURIE ANNE COOLEDGE	Innisfil Hydro
MARGARET NANNINGA	Kitchener-Wilmot Hydro
CAMERON McKENZIE	Milton Hydro
ROBERT GORDON	Ministry of Energy
DAVID SAVAGE PHIL MARTIN	Oshawa Hydro
JUDY KWIK RICHARD STEPHENSON	Power Workers' Union
VITALIKA QUENVILLE	PowerStream
DARRYL SEAL DMITRY BALASHOV	Toronto Hydro Electric System Ltd. (THESL)
BILL HARPER	Vulnerable Energy Consumers' Coalition
WAYNE ARMSTRONG	Welland Hydro
SUSAN REFFLE	Whitby Hydro

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

Description	Page No.

NO EXHIBITS WERE FILED IN THIS PROCEEDING

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

Wednesday, September 16, 2013

--- On commencing at 9:34 a.m.

MS. CONBOY: Good morning, everyone. My name is Paula Conboy, and I'm a Board member at the Ontario Energy Board. With me today is Marika Hare, and also joining us are other Board members, Cynthia Chaplin, Board member and Vice-Chair, Allison Duff, and Christine Long. Behind them we have, well-known to everybody here, Brian Hewson, Lisa Brickenden, and the Board's expert, Dr. Larry Kaufmann.

Thank you very much for coming today and participating in our stakeholder conference on the empirical research in support of incentive rate-setting, Board No. EB-2010-0379.

Just a quick recap for the purposes of transcription. The process to date -- last Friday the Board issued its draft report, entitled "Report of the Board on Empirical Research to Support Incentive Rate-Setting for Ontario's Electricity Distributors ". This report sets out the Board's proposed policies and proposed approach for the rate-setting adjustment parameters for incentive rate-setting for electricity distributors and the benchmarking of electricity distributor total cost performance.

The Board also posted on its website an updated PEG report, which is referenced in our draft report.

Consultation, as most of you will know, began with the release of the RRF report in October 2012 and has culminated in the proposed policies set out in this draft report.

In developing the proposals set out in the draft report the Board has considered the input from all stakeholders and their expert consultants; namely, Dr. Lawrence Kaufmann, Professor Adonis Yatchew, Dr. Frank Cronin, Mr. Steve Fenrick.

The materials generated for and through the consultation related to performance and benchmarking, as well as in relation to the RRF overall, have provided us with useful background and context for the issues considered in this draft report.

The purpose of today: We are here to listen carefully to various presentations that will be given today on the proposed policies and adjustments set out in the Board's draft report. A final report will be issued on September 25th -- oh, sorry. The final report will be issued following consideration of final written comments on September 25th. I'm trying to compress that timetable even more.

And as you know, we're trying to work back from having systems in place and policies in place so that distributors can avail themselves of this price-cap IR regime for the 2014 rates.

Our goal today is to foster a full and frank and comprehensive discussion, following which we report to our colleagues at the Board, who collectively will make a final determination with respect to the rate adjustment parameters.

So today's the day, hopefully, that everybody, if you have comments on the presentations that you hear, questions on the presentations you hear, if you have comments on our draft report, please make yourself known today. Tell us. Give us those comments. It would be unfortunate to sort of walk out into the hallway and overhear people saying, Jeez, you know, I wish I had said this or I should have asked that question. Now is your time. Please, don't be shy over the course of the day to ask any questions.

Marika and I will facilitate today's discussion in a direction that will be of help to us and our colleagues in rendering our final determinations, but we also don't want to inhibit the exchange of ideas that we're looking for today.

Logistics. As you know, this consultation is being transcribed and is also being heard via webcast. Therefore, when you have any questions, please do clearly identify yourself, where you're from, and that will help those who are listening in to know who is speaking in the room, and it will also help our court reporter to correctly attribute your comments.

We hope to adjourn today by 4:30. We'll take a morning break and an afternoon break. Typically those are about 15 to 20 minutes. We will stop for lunch for about an hour, and we'll try to fit those schedules so that they represent least inconvenience to our discussion and our presentation, so we're not going to give set times at this point.

Now, we're also cognizant of an ADR that's being conducted in the room next to us. I think we have canvassed the room and confirmed that nobody in this room is involved in that ADR. If I'm wrong, please let me know.

We will generally follow a pattern where we'll have one of the experts, and Mr. Shepherd, you also will be making a presentation today. We'll have the presentation and some discussion that we'll follow. So let's let them get through their presentation. Then we'll ask questions. The only exception is that Marika and I reserve the right to barge in at any time with certain questions.

So before we begin there are some general housekeeping. I don't see anybody in the room who has never been here before, so you all know that the washrooms are outside and on either side of the elevator banks.

What else? We do have evacuation procedures in case of an emergency, so if there are any funny alarms that go off that suggest there is an emergency I will suspend our meeting and provide you with the necessary instructions so that we can all get out safely.

Before we start with our presentations, are there any -- does anybody have any preliminary matters, like Ms. Hare?

[Ms. Conboy and Ms. Hare confer]

There is a matter of coordinating how we're going to deal with the high-voltage and low-voltage issues. I think Lisa was hoping to canvass some people over a break, and you will deal with that later on this afternoon.

And perhaps before we get started we could get a sense of who we've got in the room, so if people could introduce themselves that would be great. You're all excused, because you've been previously introduced.

Carm, can we start with you, please?

APPEARANCES:

MR. ALTOMARE: Carm Altomare. I'm with Hydro One Networks.

MS. KWIK: Judy Kwik. I'm consultant to the Power Workers' Union.

DR. CRONIN: I'm Frank Cronin, consultant at Power Workers' Union.

MR. STEPHENSON: How many years have I been pushing the button at the wrong time?

MS. HARE: Well, I'm glad you said that, Mr. Stephenson, because we were thinking it.

MR. STEPHENSON: Richard Stephenson. I'm counsel for the Power Workers' Union. Thank you.

MR. YATCHEW: Adonis Yatchew. I'm here with the EDA.

MR. TUCCI: Morris Tucci, with the EDA.

MR. FENRICK: Steve Fenrick, here with the Coalition of Large Distributors.

MR. SHEPHERD: Jay Shepherd, School Energy Coalition.

MS. CONBOY: Thank you. Second row?

MR. MacINTOSH: David MacIntosh, with Energy Probe, and with me today is Dr. Larry Schwartz.

MS. CONBOY: Thank you. Good morning.

MS. SCOTT: Jane Scott, from Hydro Ottawa.

MR. McKENZIE: Cameron McKenzie, Milton Hydro.

MS. CONBOY: Cameron McKenzie, Milton Hydro.

MS. DeJULIO: Gia DeJulio, Enersource Hydro Mississauga.

MS. CONBOY: Thank you.

MS. REHBERG-RAWLINGSON: Tracy Rehberg-Rawlingson, Halton Hills Hydro.

MR. GRIBBON: Jamie Gribbon, Horizon Utilities.

MS. GIRVAN: Julie Girvan, Consumers Council of Canada.

MR. HARPER: Bill Harper, consultant for VECC.

MR. EAMER: Gord Eamer, with CHEC Association.

MR. PROCTOR: Dave Proctor, Cornerstone Hydroelectric Concepts.

MS. COOLEDGE: Laurie Ann Cooledge, Innisfil Hydro.

MR. FERGUSON: Dave Ferguson, Entegrus Powerlines.

MS. CONBOY: Who else have we got back here?

MR. MARTIN: Phil Martin, Oshawa PUC.

MR. SAVAGE: David Savage, Oshawa PUC.

MS. CONBOY: I think you may -- you're going to have to come up, and also, it gives people who are on-air -- sorry, joining us via webcast to get a good sense of who is in the room.

MR. MARTIN: Phil Martin, Oshawa PUC.

MS. CONBOY: Thank you.

MR. SAVAGE: David Savage, Oshawa PUC.

MS. NANNINGA: Margaret Nanninga, Kitchener-Wilmot Hydro.

MS. COOPER: Maxine Cooper, Hydro One.

MS. REFFLE: Susan Reffle, Whitby Hydro.

MR. SEAL: Darryl Seal and Dmitry Balashov, Toronto Hydro.

MS. CONBOY: Thank you.

MS. SOUCIE: Michelle Soucie, Essex Powerlines.

MS. QUENVILLE: Vitalika Quenville, PowerStream.

MR. ARMSTRONG: Wayne Armstrong, Welland Hydro.

MS. CONBOY: Thank you. Mr. Gordon, don't think I don't see you back there.

[Laughter]

MS. CONBOY: You should have sat right behind the pillar.

MR. GORDON: Robert Gordon, Ministry of Energy.

MS. CONBOY: Thank you. Does anybody have any preliminary matters before we start with the presentations? Of which I will give you the order in a minute.

MR. HEWSON: Sorry, just to remind everybody that is listening in, if they want to send in a question they can send it to rrf@OntarioEnergyBoard.ca, and we'll read it out during the...

MS. CONBOY: Thank you. So Lisa will jump up and down and tell us that there is a question coming in via e-mail.

Okay. So I think the order that we're going to go with is Dr. Cronin will go first, Prof. Yatchew will go second, Mr. Fenrick third, and Mr. Shepherd, you are fourth on the list. That's the list of who we have who wanted to make presentations.

We didn't anticipate Mr. Kaufmann making a presentation today, but we have advised him that he is of course free to ask questions and make any follow-up comments.

So if you guys want to stay in the front row and make your presentations, that's fine. We're in your hands.

Dr. Cronin?

Sorry, Mr. Shepherd, you look perplexed over there. Okay.

MR. SHEPHERD: It's my natural look.

[Laughter]

MS. CONBOY: Sorry to point it out, then.

[Laughter]

MR. SHEPHERD: Thanks.

PRESENTATION BY DR. CRONIN, POWER WORKERS' UNION: OBJECTIVES, LEGACIES, AND IMPERATIVES REGARDING THE OEB’S PROPOSED IR

DR. CRONIN: Thanks for the chance to come before the Board again. I was just reflecting that at this time in 1998 when we started this, I had no idea that I would be so pleasantly engaged for 15 years in topics like productivity and restructuring. So it's been an interesting 15 years. And I'm hoping that there are some interesting aspects of the proposal that we can talk about today.

I wanted to comment briefly, you know, over the recent past and the last half-decade, we have expressed concerns about what we view as structural flaws and mal-incentives in the Board's IR. These topics include the non-inclusion of line losses and reliability performance, the fact that up until recently it hasn't been total cost, and there have been various changes in the specification of the IPI.

To overcome some of the data issues, we've recently proposed using a dual approach, which relies upon the Board's own rate data. And we have offered comments about benchmarking, and we've basically provided some comments regarding the fact that a DEA non-parametric approach has been widely used around the world for utility benchmarking, and we've actually used it with the Ontario data since 2001.

For the rest of the presentation, I would like to review where we've been and where we might be going. Before I do that, I would like to take a brief diversion and maybe pick up on some of the findings that PEG had reported in their recent update, and maybe put those into the context of what we have been proposing.

In the recent PEG update, if we go to page 7, I do have a line that I added to that, that basically summarizes some of the information that PEG reported, which was that in 2012 the growth in TFP was minus five percent, and that was driven largely a six percent increase in inputs and the input increase was driven by an 11 percent increase in O&M. And I guess there are various ways of interpreting that.

We think we have an understanding of what might be causing that surge that PEG reported.

And to give you an idea if we skip ahead page 13, now, in the submissions to the working group and in the report that we provided some time back, we had highlighted some of the information on a number of LDCs. I think we had somewhere around 16 LDCs that we highlighted the information.

And this graph provides information on five LDCs over the 2005 to 2011 period. And this is similar to the other -- the sample of 16 that we included in the report. And what we think we're seeing with the SAIDI data that was reported was a fairly consistent increase in the SAIDI numbers, the absolute SAIDI numbers, which would indicate a weakening of the reliability.

So our explanation for the -- or partial explanation for the surge in O&M in 2012 is that some of the LDCs were responding to the day-to-day report in 2011. So we think there is an explanation for why that happened.

Now, I think the larger issue here is, in abstract, in the abstract you would view a five percent decrease in TFP or an 11 percent increase in inputs or -- I'm sorry, a six percent increase in input and 11 percent increase in O&M possibly in a negative light. And the reason why it might be viewed in a negative light is because it's being viewed partially. If you included the consequences in the calculations of what happened with those expenditures, like the six percent increase in inputs, if you included the consequences on line losses and reliability and you had a comprehensive measure of TFP, then the indicator would be consistent. It would contain within it both the beneficial aspects of the spending and the spending itself.

So what we had been proposing, if memories will recall, in 1st generation we had included line losses in the calculation for TFP. And the TFP without line losses was about -- this is a long time ago, but I'm thinking it was about 0.4 percent per year for 10 years. Including line losses for which utilities had spent a lot of money getting those corrected, it actually doubled the TFP performance. So in 1st generation, by including the line losses themselves as an offset in effect to the other expenditures, we were able to show the utilities were being fairly effective with their spending.

So we think that it's very important that the right measure of TFP be used to benchmark the utilities going forward, and that if it were comprehensive by including line losses within the inputs, so as they spent money to offset the line losses, they would show lower inputs, and also consequently with the expenditure on O&M capital having the beneficial impact on reliability as an output, then that would be more rational and would provide more consistent incentives to the utilities.

So we just wanted to divert from the presentation to maybe offer a few comments on PEG's results, and to say that you have to really put those numbers into a context of what's happening as a result of those expenditures.

Now, if we go back to page 3, the whole point of IR is to incent certain good behaviour and mitigate bad behaviour, and we would expect organizations under IR to recognize and respond to these incentives.

And our point is that these issues have to recognize going forward that there is a set of legacy issues that need to be carried forward into the future IRs, just as there were when they went from the old regime, the MEUs, the non-corporatized entities, into the corporatized entities.

And some of the features of the current and past IR regime have to do with using OM&A benchmarking to rank LDCs, not incorporating losses, not incorporating reliability standards, and the three-on-one-off term, which we think probably acted to mitigate the incentive features of the IR by causing this on-again/off-again incentive attitude.

And then just to briefly kind of summarize some of the results as we see them, we think that the IR over the past, say six years, five or six years, it's lowered TFP for some of the LDCs, it's lowered efficiency, and it's lowered reliability. It's increased line losses, it's increased the amount of labour and overhead that's been capitalized, it's increased future profits and future rates for a number of the LDCs.

It's acted to reduce the share of equipment in capital additions, and it's lowered the bang for the buck with investment because of the lowering of equipment as a share of capital additions and the increase in labour and overhead.

We think that the incentives have not reflected the express customer preferences not to have a degradation in reliability, and we think the Board's path-breaking work with the Polaris study made that quite clear, that the expressed willingness to accept compensation was very clear. We're going to talk about that in a little bit, in a minute.

We think some of the efficient LDCs have been penalized and some of the less efficient have been rewarded because of these ranking mistakes. And we think that some similar problems could potentially go forward with the fourth-generation.

We would offer up very briefly a set of objectives that we think should be possibly used to reflect upon what the implications are for the future IR, and these have to do with -- we think the IRs should be customer-centric and driven by a customer focus.

And for example, the Polaris study in 2010 that the Board conducted was quite clear that they were overwhelmingly opposed to a degradation in utility.

As we've said, we think it should be comprehensive in costs, operations, and outcomes so that you can see a unified result, having to do with all of the costs and all of the outputs. We think it should be adaptive, and that -- and we think Ofgem is a good example of an organization that has used the data to reflect on, say, these consequences that one expected and deal with those, you know, sort of within term.

We think it should be input-neutral, and we think that the choices that utilities make should be driven by input prices, technology, and the legacies they carry forward, not so much by the regulatory regime. We think it should be rationally green and that it should strive for a socially optimal outcome.

Now, to set the context, our data shows that -- and I'm not going to spend a lot of time on this table. I just want to summarize. What we found, whether the two big utilities are included or they're not included, that utility was negative for basically a decade. I'm sorry, productivity growth was negative for most of the decade, and I think, you know, that needs to be better understood.

Why did we have ten years of negative productivity growth? How did the incentives -- and, you know, clearly they had an impact, but at the same time you had things like recession, you had things like infrastructure, requirements that would be factored in.

And we think that one would have to better understand how those impacted these performance data. And so you would know going forward what a secular TFP trend would reasonably look like.

The data that we presented in that table on page 6 was based on a Törnqvist quantity approach. You can also do the same analysis with what's called a dual approach, which is using the same equation, but you're looking at the monetary side of it. So you're using rate data and input prices.

And we looked at that using the rate data and input prices, and we basically came up with nearly identical results.

So we think, you know, especially over the past three or five years, that the results were negative, but even going back a bit before that with just the quantity data, you're looking at productivity growth that maybe was not up to the historical norm.

Page 8, when you look at the -- when you look at the data for the LDCs, there seemed to be over a majority that had negative growth. So more like 60 percent. So you had 60 percent with negative growth, you had about a fifth with growth around zero, and then a fifth with more positive, stronger growth and productivity, and we think it would be useful for the Board to understand why there was this difference and then build results of that information into the incentive structure.

Again, if you go back to 1st generation you had growth of about .8 percent for a decade, and when you look at the last five years it was basically double that for almost everybody.

So clearly there were different requirements at that period; namely, they didn't have the same infrastructure replenishment requirements. But obviously the performance varies over time, and even in the same time period, if you look at the distribution currently, you see 60 percent being negative. So it's not as though there are a few dominating the results. It's more pervasive.

One of the legacy issues we wanted to spend really a very short period on was this issue of incenting -- incenting on the O&M benchmarking. And this is a very confusing table, but if you look under 2000 and you look at that black and red row there, what that shows is that in 2000 O&M for the whole industry exceeded capital, and it exceeded it by about 30 percent.

Now, if you look at that same data ten years later, what you find is that capital became much larger than O&M. So you went from a labour/capital ratio of 130 percent down to 75 percent.

Now, this is pretty dramatic stuff. These are three large -- I show individually three large LDCs, and the three that I show are large LDCs, and you can see that that capital/labour ratio has been substantially affected. And so the decisions that the LDCs were making in the context of those incentives resulted in fairly dramatic shifts in input shares.

And I guess our question is, was this really the most efficient choice or was it a reflection of the fact that they didn't want to be identified as being on the lower end of the O&M ranking.

MS. CONBOY: Sorry, can you go through this table with me one more time?

DR. CRONIN: Sure.

MS. CONBOY: You've got labour capitalization for aggregate and selected --

DR. CRONIN: Yes.

MS. CONBOY: -- LDCs.

DR. CRONIN: The --

MS. CONBOY: You didn't hear me? Well, maybe I'll have a second to ask it better, but could you go through

this table with me again, please?
It shows labour and capitalization for aggregate and selected LDCs for 2010?
DR. CRONIN: Yes. The lower half of the table shows the data for three LDCs, 1, 2 and 3. And the only data I showed for each LDC was basically the end ratio.
So if you look at LDC 1 and you go to the right of that, they started out at 178 percent. So that was the labour/capital ratio in 2000 for that LDC. That fell to 79 percent 10 years later.
MS. CONBOY: Okay.
DR. CRONIN: It's a little bit confusing. I'm sorry for that.
But the point is basically where they started with their choices on inputs was very different than where they ended. And was this a reflection or -- in other words, did this contribute to the fall in productivity, the fact they were making non-optimal choices?
MS. HARE: Is there a reason why you can't identify the LDCs? The only reason I'm asking is to understand whether they are anomalies in that.
DR. CRONIN: I just didn't choose to put their names on. I mean, I know who they are.
MS. HARE: Are they the ones that were also excluding when we're doing TFP? Because we think they're outliers? I mean, that's three --
DR. CRONIN: I chose three that were large so they wouldn't be viewed as being too small to matter. And I

actually chose two of the most efficient from 1st generation and one very big one. So I'm looking at the two that were identified as the most efficient in the province in 1st generation, and looking at what their choices were.

MS. HARE: Can you also explain to me -- maybe this is an obvious question -- what is "OMOM&A"? It's a typo?

DR. CRONIN: That's a typo. That's a typo.

MS. HARE: Okay. Good.

DR. CRONIN: That's my terrible formatting.

MS. HARE: That's fine. Then I understand it.

DR. CRONIN: I'm lucky that you can understand anything in this table.

[Laughter]

DR. CRONIN: What we did was we collected total costs for 1st generation, and we had a sense of who the most efficient performers were. I said to myself: How much have they been affected by the whole conglomeration of influences, including the IR incentives? I said: Well, let's take two of the most efficient and see what happened to them.

And they had very significant changes in their capital/labour ratios.

MS. CONBOY: So going forward, where we have a -- we're moving to more of a consistent capitalization policy, with the Kinectrics report and the two components that the LDCs are doing, do you see that this variability is going to level off? Like, should it be as much of a concern going forward as it was perhaps in the past?

MS. HARE: I actually had the same question with IFRS. It's more prescriptive as to what can be capitalized. So is this now an issue that's being solved?

DR. CRONIN: I'm not speaking directly to those initiatives, but I think -- I think there's probably still a lot of leeway in what's being done. But if they weren't being incentivized, I guess my point is if they weren't being incentivized to reduce O&M then they wouldn't have gone out of their way this much to capitalize so much more, if it didn't matter -- a dollar of cost is a dollar of cost. And if the O&M is treated the same as capital, when they get evaluated in their benchmarking or their TFP, then presumably they will do what's most efficient and rationale from their perspective, because they won't view the O&M as being so onerous.

I guess the way I would say is from a commerce point of view, it would be better to provide the right set of incentives so tha5t you don't have to have accounting people going in and auditing to see if they're doing the right thing.

MS. CONBOY: Thank you.

DR. CRONIN: And again, just to follow up on this table, I did want to talk about this bang for the buck for a moment. And that's on table -- the unidentified -- there it is. Page 10.

What I showed was, for a selection of LDCs, what the share of capital equipment was. And if you go down for example to the second row, LDC 2, you can see that there is a 60 percent there, which means that of their capital additions, those capital additions were comprised of labour and overhead of 60 percent. So 60 percent of what reportedly was going in the ground wasn't equipment; it was labour and overhead.

And for that -- if you go down for example to LDC 5, their reported equipment and material is 16 percent of capital additions. So there's a fair amount of variation here, you know. You could potentially have a lingering problem, where, say over the past few years, more than normal of O&M has been capitalized and less equipment has been put in. So that if you thought you were putting in a million dollars of capital additions, say in 2011, it wouldn't be the same million dollars as you did five or 10 years earlier. You would have had much more equipment and much less overhead.

MS. CONBOY: How does -- the fact that contributing capital doesn't find its way into rate base or depreciation, does that impact these numbers at all? Or your conclusions from these numbers?

DR. CRONIN: No, no.

MS. CONBOY: Thank you.

DR. CRONIN: The next slide again -- I think we talked about this briefly -- this was simply -- what I'm showing are three LDCs and, starting in 2006, under what rate adjustment mechanisms did they operate.

So I guess I was surprised when I looked at this and I saw that there was a fair amount of variation for any individual utility; what they were operating under from one year to the next changed a lot.

And it seems to me that under those circumstances, it would be harder to come up with a long-term plan for a utility and make distinctions about investment, because you're really not sure what the consequences are going to be, you know, two or three years out.

So we think that this change from year to year may have reduced what normally would have been IR incentives to further efficiency.

MS. CONBOY: Which, in your view, if we moved from using a TFP to a data development analysis approach, would address this? Or was it still going to be an issue in the DEA calculation?

DR. CRONIN: No, if you went into a long-term IR that was consistent in terms of evaluation like, say, the Norwegians did, where they used the DEA for two things -- they used the DEA to come up with their estimates of TFP. You can do that. And you can also use the DEA to rank the absolute efficiency.

So you can do -- you can both get a sense of the year-to-year changes and you can get a sense of the absolute level of efficiency or inefficiency for a utility.

But -- and what they did was they basically said: We're going to do this for five years, and at the end of five years we're going to do another -- another go at the analysis to see where you stand on the improvements.

MS. CONBOY: I'm trying to tease out the comments that you're making that have to do with systems that were put in place, because we have 73 LDCs going through their rate adjustment mechanisms every year, which led to the staggering. And then understanding that some will be in cost of service years, some will be in IR years, versus the issue of: Hey, Board, we don't think the TFP is the right way to go.

So it seems to me this is more an issue of the 73 utilities that are going through this process.

DR. CRONIN: The statistics of dealing with the 73, yeah. You could set up a regime with either TFP or DEA, or using both. But it's the fact that you're putting in place something that's going to last for five years, say, and they know what the incentive scheme is going to be for those five years.

MS. HARE: Actually I don't understand your point. So are you saying that five years is a problem, or it's a good thing?

DR. CRONIN: No, it's a good thing.

MS. HARE: Okay. So what's been proposed now in the Board report is cost of service plus four years. So you're in agreement with that?

DR. CRONIN: Yeah, with the proviso that what happens in the four years is very important. You know, the implementation of the IR in the four years is very important. You can come up -- as we've just talked about -- with different versions of TFP, some of them not being comprehensive, and you may still have ongoing incentive problems if you don't have a comprehensive measure.

I'm going to skip 12 and 13, because we've basically talked about that, and maybe just spend a minute to talk -- we think that the Polaris study was very useful. We think it shed a lot of light. I think there might have been maybe a difference of interpretation with the Polaris study, but we think if you look at the numbers that there was a sizeable number of customers in the province who expressed some dissatisfaction with the reliability.

Now, there was a difference in terms of what they were willing to pay, but among those who were willing to pay some amount, that was almost $200 for improvements.

The thing that was consistent was that almost nobody wanted a degradation. And we're going to talk about that in a little bit. But what I was surprised about -- and I'll just offhand say that, you know, this has been incorporated by Ofgem and the original regulator, as well as a number of others, and they each have their own bent on how to incorporate it. But they have tried to make amends to their ongoing IR to reflect some of the mal-incentives that you, you know, you would induce in utilities under IR.

What I was surprised about was the similarity between the Ofgem results and what the Board found in Ontario. The proportion of people responding in terms of how much -- who would be willing to pay, how much they would be willing to pay, those were very similar to Ofgem's findings, and Ofgem took those results and said, Well, we're going to put in place a much more rigorous back stop. We're going to have guaranteed payments if they lose power, and these are going to vary by class of customer, and now they've revised those even more.

So I think they took the results and I guess concluded something different, but they were very similar between Ontario and the U.K.

What I found interesting about the Ontario results was that almost nobody would have accepted money for degradation, so they're basically saying, You can't pay me enough to degrade my service. But among those who offered a response -- so that was a minority, right -- who offered a response, the number was about $28 a month, which is almost identical to a distribution bill.

And I think part of the confusion is, is that the customers aren't viewing distribution as what they're buying. They're buying power. And they want the power. And power is worth a lot to them. But the way that jurisdictions have gone and they've restructured, they've broken the power from the distribution.

So when some customer comes back and says, I won't accept $100 a month for degradation. It's just worth a lot to me, but then you find a minority who said, Okay. I'll take compensation, and I'll take $28 a month, well, that's their value of the power. It's -- you know, and to them power and distribution are -- you know, they're one and the same thing. They don't see the distinction.

But when you look at those results and you say, Oh, $28. But that's the same as a power bill -- I mean, you know, the distribution bill. Isn't that a lot? Well, no, not in the context of the customer.

And so we think that the customers have been quite -- and we're glad the Board put that survey in place. We're glad that they asked both WTP and WTA and that they provided enough information to reflect upon the fact that the customers in Ontario were quite adamant about the value that they associated with ongoing power.

MS. CONBOY: So if we're dealing with value of money and value -- customer-value issues in the RRF report, through the scorecard and through other measures or methods, what I think I hear you saying is that's not the appropriate place to do it. You can actually weave those components, that value proposition, in the actual rate-adjustment mechanism.

DR. CRONIN: Yes. Yes.

MS. CONBOY: Thank you.

DR. CRONIN: Let's skip ahead to -- it's what Ofgem and under various means, say Norway, does. I mean, there are many regulators, you know, who put in IR some time ago who in one way or another factor reliability directly into their system, and Norway basically dings the top line if -- and they do it on a yardstick basis, so they're looking at 200 utilities, and they're looking at relative utility performance, and if their perform -- if utility A isn't up to snuff relative to their period, they get dinged, and Ofgem does it a little bit. You know, they have side payments. But, you know, they have guaranteed payments, so if your power goes out, you know, depending on what class you are, you might get 100 pounds.

I mean, in Massachusetts we just got -- the attorney general collected -- I don't remember what the total was, but it was way in excess of $30 million in fines to the utilities, because of the performance of the distributors, you know, the past couple years under those big storms. So, you know, those were pretty sizeable penalty payments.

MS. CONBOY: That's not necessarily in the calculation of the IPI minus X, is it, or is it --

DR. CRONIN: No, no, no, this was a lawsuit that she brought that had nothing --

MS. CONBOY: No, sure, but what you were describing in Norway and aside from the lawsuit in the -- sorry, in Ofgem as well, is that you've got the IPI minus X, or you've got the rate-adjustment mechanism. As a side you also have the service-quality indicators, and you get dinged, if you will, in your words if you're not meeting those, but it's not incorporated in the actual --

DR. CRONIN: Well, it's almost -- the Norwegians, it's almost incorporated in the IPI minus X.

MS. CONBOY: Okay. Thank you.

DR. CRONIN: Ofgem is a side condition, yeah. So they've done it very -- they've done it many different ways.

MS. CONBOY: Thank you.

DR. CRONIN: I wanted to take just a moment to talk about line losses. And as I said, you know, we examined this, especially in 1st generation, and I guess, you know, losses can be as much as 20 percent of total distribution costs, and they can be as much as $150 a year per customer.

So these are not inconsequential numbers. They can vary quite a bit across utilities. And they can vary quite a bit even for the same utility over time. And we think that it's imperative that this be brought in under the IR regime, and we're going to show in the next slide kind of the variation over time and within the utility and across utilities in line-loss performance.

And I know every utility is different, but I think what we've seen historically in Ontario is the fact that the utilities have, based on incentives, really gone after line losses, and they have been remarkably productive in getting them under control, and so what I would like to look at on page 19 is -- this is a history from 1988 to 2011 for three selected LDCs.

MS. CONBOY: And where is the data from, Dr. Cronin? Can I go and find the data somewhere?

DR. CRONIN: Yes, yes. Well, it's under 1st generation data, and it's also produced by the yearbooks that were put out by Ontario Hydro --

MS. CONBOY: That's right. You got it from the yearbooks.

DR. CRONIN: Yes.

MS. CONBOY: All right. Thanks.

DR. CRONIN: So if you look at utility A you can see in 1988 that its line losses were 3.7 percent of the energy use used, and that there were fairly strong incentives starting in the 1990s to get their costs under control. And you can see that they went from 3.7 down to 2.3 and finally 2.1 percent.

And this is true of each of the three utilities. They started at different levels and they got to different end points, but they all had very dramatic changes. And this is what we reflected in 1st generation TFP, that this performance actually increased the historical TFP by 100 percent.

Now, unfortunately, after getting to some of these fairly low numbers, you know, a number of utilities have had their line losses creep back up. And each one is going to be faced with different circumstances, and the whole calculation of how much should I spend on O&M or capital to get these lower is really something that they would have to evaluate.

But if they're not being incentivized by an IR regime that says, We want you to find the optimal level of line losses and reliability within the context of the Board's IR regime, and you figure out what the best way to spend your budget is.

Page 20, we've actually done a couple examples where we've incorporated line losses as we did in 1st generation, and it does make -- for a number of utilities it would make a material impact on their reported results, both positive and negative, depending on what direction their line losses have gone the past few years.

We do think this is a critical issue. The customers, they pay for this but they basically have no incent -- they have no control over it, and we don't think right now that the utilities have enough incentive or the right incentives to properly reflect what the optimal level of losses will be.

Page 21 is just a reflection on this whole question about the productivity over the past half-decade or decade. And again, we found, both with the price dual and with the quantity-based TFP, that those results were consistently negative.

If you look at the culmination of that performance for some of the LDCs, what you're looking at is a drop of as much as 12 percent in their absolute productivity. So this has been, for some of them, a fairly marked -- a fairly marked change in their productivity.

MS. HARE: I want to go back to line losses. As you're aware, in a cost of service application the line losses are looked at, and if they're considered to be too high they are reduced so that the amount is not included in the revenue requirement.

So you're saying that's not enough?

DR. CRONIN: Well, I'm saying -- I'm saying that I think if the utilities were incentivized to come up with the right balance of losses, capital and O&M, it would be preferred, rather than in the abstract.

I mean, for -– so I guess we're saying that we think the utilities should operate with the correct incentives, but then they make the decision. Do they want to let the losses increase because they will save more money on capital and O&M, as opposed to someone coming out, you know, a third party kind of coming down and saying: Well, these losses aren't right; you need to reduce those.

MS. HARE: Thank you.

DR. CRONIN: Based on our DEA analysis, we think that the frontier, the efficiency frontier has actually receded, and that the frontier firms have become less distinguishable from the interior or less efficient firms.

So we think that this is a fairly serious issue. I mean, it is different.

The Norwegians have published a fair amount on this, and when they started they thought that the frontier would be growing at one and a half to two percent a year. So their conclusion was that even the most efficient LDCs should have some improvement in productivity as an expectation, because the frontier will be growing year after year after year.

Now, what we've seen here is that both the interior and the frontier has degraded somewhat. We think it's critical that more be done to ferret out what the causes of, say for example, the minus five percent drop in TFP in 2012 was, and that the incentives going forward reflect a more rational approach to giving the utilities more responsibility, but also holding them accountable for these other outcomes that affect the consumers, like line losses and reliability.

Page 23 is just a reflection -- when you use different methodologies, you're probably going to come up with different results, and that's certainly true here. I took a handful of LDCs and I calculated what our efficiency result was and then compared that to PEG's. And for these and a number of others, there are fairly large differences in how we would judge the efficiency or inefficiency of those LDCs.

And so we think that there really needs to be more that's done -- it's one thing -- I think if you looked at PEG's TFP results and our TFP results, they're not that different, when you look at the aggregate.

Now, there has been this big fall-off in the past few years. We were showing it in our data all along. PEG now is reporting 1.3 negative for 2011 and the minus five for 2012. So we think that's consistent with what we've been finding. We think that, by and large, the averages are reasonably close. And we did both the price tool and the quantity.

We think on that you can come up with some conclusions about the averages. Now, understanding why the averages are the way they are, we don't think anyone is there yet. And we think that's really critical for the Board, to get the right levels in these parameters like the X-factor going forward.

But we do think that what we're seeing are very significant differences when you look at individual LDCs, and you look at PEG's results, say, versus our results.

Now, some of that is due to data. We have a data record going back into the -- decade after decade after decade. Part of it is due to difference in methodology. PEG is using a statistical approach; we're using a non-parametric approach. But there are very big differences for some of the utilities, and we think that needs to be better understood.

Just a couple comments on the IPI.

MS. CONBOY: Sorry, Dr. Cronin. So on aggregate, you're somewhat on the same -- coming up with the same results?

DR. CRONIN: We're in the same ballpark on an aggregate basis.

MS. CONBOY: But when you look at specific LDCs, you do see some marked differences. How -- would the fact that we have three different options, rate options, available to distributors assist in addressing that issue?

DR. CRONIN: It certainly would be an improvement. I guess the longer I think about these choices, I guess the more I kind of -- I like what Ofgem has fallen into, where they're looking at peer group-based long-term incentive plans.

I like what Norway has done, where they're, again, looking at long-term incentive plans that were based on peer group evaluations. But they spent a fair amount of time collecting the data, getting it all sorted out. I don't know how that's -- I guess the devil's in the details. How does it get factored in? How do you go about evaluating one utility in Ontario and whether or not it's at the right level of efficiency?

I think the fact there are more choices is better than what's been existent in the past, but I'm not sure about, going forward, how that gets -- how the details get filled in there.

MS. CONBOY: Thank you.

MS. HARE: Can I take you back to slide 23? Can you expand a little bit on that last sentence? "The Board's proposed benchmarking is biased and will lead to penalizing more efficient LDCs and rewarding inefficient ones."

DR. CRONIN: Yes. What we found was –

MS. CONBOY: Hang on just two seconds for the court reporter.

MS. HARE: Sorry, I'll just repeat the question for the court reporter.

It was -- the last sentence on slide 23 says:

> "The Board's proposed benchmarking is biased and will lead to penalizing more efficient LDCs and rewarding inefficient ones."

DR. CRONIN: If we believed our results -- which we probably would tend to do -- we have results that are different than PEG. We're showing result -- we're showing utilities for which -- they say they are inefficient, being actually efficient. And some of the ones that they say are efficient, we actually are saying they're less efficient.

So I guess the term "bias" would be -- if we were closer to the truth than PEG, then if you applied PEG's results, then in a number of cases you'd be judging the utilities as efficient when they were inefficient and conversely.

MS. HARE: Thank you.

DR. CRONIN: I wanted to take just a minute to talk about the IPI, because I did notice that the Board had a proposed change in the IPI going to a 2-factor, and we think that that could be a significant -- a significant error, and it could end up being a huge disincentive to the LDCs going forward.

If you look at page 24, this is the IPI that we calculated. Now, this is a bit different than PEG's IPI. First of all, we have a different weighting on capital than they do. Our weighting on capital is lower than PEG's. We also don't bring in salvage value, which really impacts the volatility of the IPI.

So we think that you can calculate an IPI where you don't have substantial volatility. And when you look at the volatility on page 24, it certainly is less than was the case for a number of rate changes over the past three or four years.

So we think that the IPI historically can actually be lower volatility than what has happened in fact. And we think it actually gives the right signals.

Page 25 just presents for two utilities the actual rate changes that they operated under from 2007 to 2011. And you can see that for utility A there was an 8 percent rate increase in 2007, a 9 percent increase in 2009. For utility B there was a 16 percent increase in 2010, and I could have had a number of other selected utilities that would have showed similar impacts.

So there have been -- there has been a fair amount of volatility in the past four or five years for rates. We think that the IPI, at least historically, our IPI would be less volatile, but it's very important that this be factored in.

If you look at page 26, what this is, is, this is a recent graph on the ten-year Treasury note. So we're looking at the U.S. Treasury note, ten-year Treasury note, from May through September.

Now, you know, it was at historically low levels. It's gone from 1.6 to just under 3 percent. So even 3 percent would be historically low. It could go up, going forward, probably will go up going forward.

Now, what's been the consequence of that, if you go to the next slide, I've graphed the share prices of four large U.S. LDCs. And you can see that the shares over the past month have fallen, let's say around 10 percent. And we think that one of the primary reasons for the drop in share prices -- and these are some of the big ones -- Edison, Scana, Southern Company, AEP -- so we're covering utilities in the south, the southeast, the northeast, and the midwest.

We think that this is a reflection of the market basically saying that these increasing interest rates are going to impact the value of these companies. And the increase has happened already. It's the expected increase that's happened.

And so if you don't -- if you don't have a mechanism to adjust the revenue for those changes that are outside the utility's control, like in financing costs, what we say on 26 is that, given that capital is 50 percent by our calculations, that's basically what was true in 1st generation. It's pretty much true what's now.

We'll probably see a continuing increase in interest rates going forward. If you don't include capital specified like that in the IPI, then you're going to end up with probably providing insufficient top-line numbers to the LDCs.

MS. CONBOY: It's interesting. Unless I'm misunderstanding this, your 3-factor IPI yields lower results than the Board's 2-factor IPI, and yet one of your assertions are that the 2-factor IPI would not leave sufficient funds for investment.

DR. CRONIN: Going forward --

MS. CONBOY: Is that because going forward you've got the interest rates going up and you've got the capital factor --

DR. CRONIN: Historically we had very little change -- we had very low --

MS. CONBOY: I'm sorry, I just trailed off. I said the capital factor in the equation. That's what I meant to say.

DR. CRONIN: Interest rates were basically at, you know, at fantastically low rates the past five or six years. So they really had no impact, you know, in terms of contributing to the increase in cost. They were just low, and they stayed there.

So you had -- that's why I'm saying our IPI shows a fairly low volatility, and lower than the actual rate changes, but going forward --

MS. CONBOY: Okay.

DR. CRONIN: -- okay, with the interest rates going up, if that's not reflective in the IPI, then the utilities will be operating, in effect, in a non-recovery mode.

MS. CONBOY: Thank you.

I might turn to the other Board members first before I open it up to general questions and discussion. Have you -- are there any questions from your side?

Q&A SESSION

MS. CHAPLIN: Cynthia Chaplin here. I have a technical question. I'm sorry, Dr. Cronin, can you go back to slide 10 and just explain again how those numbers work? Because I don't think I adequately listened to your explanation. Are they percentages?

DR. CRONIN: Yes, those are percentages of capital additions.

MS. CHAPLIN: So do they add up to 100? They don't add up to 100.

DR. CRONIN: Well, there are one or two other categories, so I don't think they necessarily add up to 100.

MS. CHAPLIN: Okay. I mean, that was why I was just trying to understand. Like, I'm looking down at LDC 5. It's 21 percent labour and overhead and 16 percent equipment and materials. So you haven't identified all the components that would --

DR. CRONIN: No, I was interested in the first and second column more than anything else.

MS. CHAPLIN: And just their relation to each other.

DR. CRONIN: Yes. Right.

MS. CHAPLIN: All right. Thank you. That's it for now, thanks, for me.

MS. CONBOY: Are there questions from the floor? We'll go with that first, and then, Lisa, let me know if there is anything that's coming in via e-mail.

Mr. Shepherd?

MR. SHEPHERD: I have, I think, three questions. The first is a fairly simple one. It's Jay Shepherd, School Energy Coalition.

Can you, Dr. Cronin, provide a copy of your presentation with the names of the LDCs included in it, where you've selected LDCs? Can we see who they are so we can assess whether they're representative of what you're saying?

DR. CRONIN: I don't see why not.

MS. CONBOY: I think they're named in the yearbook, are they not?

DR. CRONIN: Yes, it's all from the yearbook.

MR. SHEPHERD: Well, we would have no way of knowing which one that he is choosing.

MS. CONBOY: No, I understand that. I'm just helping Mr. Cronin -- Dr. Cronin try to decide whether he's --

DR. CRONIN: You know, the one table that would be easy is the one we talked about, the capital/labour ratio, and so I can find the capital/labour ratio table very easy.

MR. SHEPHERD: I guess I'm concerned that any of these tables that doesn't identify the LDCs, we're going to argue that the Board can't consider it, because it can't see what the data is.

DR. CRONIN: Okay. We will make every effort to respond expeditiously to your request.

MR. SHEPHERD: My second question, is you talked about the increasing capitalization of labour from a 10 percent average to a 35 percent average, which, I agree with you, is pretty shocking. And Ms. Conboy asked, well, is that -- should that concern us less because of IFRS?

I guess I understood you to be saying not that this was accounting changes, but rather that this was -- that the system was incenting utilities to spend more on capital and less on OM&A, in fact; that is, to focus their attention on capital, because capital was less restricted in the system.

Is that -- am I understanding you correctly?

DR. CRONIN: No, I think what you're saying is -- we think it was more that they were being incented to reduce reported OM&A.

MR. SHEPHERD: So it was accounting tricks rather than actual change in what people were doing.

DR. CRONIN: Well, they were spending the money; they just weren't expensing it. They were capitalizing it.

So they might have spent the same amount of money, but it would show up differently. You would have lower OM&A and higher capital. The higher capital would be then be there for 30 or 40 years.

MR. SHEPHERD: So the higher capital was on the same things like they were say -- the utilities were saying something that would have previously been maintenance, they're saying: No, this is a capital expenditure now?

Is that what you're saying?

DR. CRONIN: Yes.

MR. SHEPHERD: Okay. Thank you.

And then the third thing is you said on page 6 that there appears to be all this negative TFP over the last 10 years, and we don't seem to know the reasons for this. So let's accept that that's true.

Does that mean that the Board should hold off making any changes to IRM until we have those answers, until we know why this is happening?

DR. CRONIN: I'm not a fan of the current IR, so you're sort of offering me a choice between two things I don't like.

I would like to know more about why the numbers are negative, and I think it would be fairer for everybody -- the customers, the shareholders, the utilities -- and I don't know how you could rationally set the parameters of an IR until you do.

But I would hate to preserve the disincentives that we have recorded here.

MR. SHEPHERD: So the answer, then, is to -- I'm not trying to put words in your mouth. I'm trying to understand. The answer is to not make any changes because essentially they would be non-empirical, but to act quickly to do the work to figure out what these -- the reasons are, so that we can make the changes as fast as possible on a good empirical base?

DR. CRONIN: Absolutely, yes. That's very well summarized.

MR. SHEPHERD: That's all the questions I have.

MS. CONBOY: That last one was an interesting question, Mr. Shepherd. Because I was going to ask the same, but more of your clients, more of the PWU in terms of going forward, but I'm assuming they're consistent with Dr. Cronin's.

Are there any other questions? Carm, would you like to go?

And then, Dr. Kaufmann, we'll get to you.

MR. ALTOMARE: Dr. Cronin, if you can turn to slide 6 and explain the reasons for those superscripts in the left-hand column? You got A and B?

DR. CRONIN: Oh, those were from the report. I just basically excerpt the table from the report we filed, and there were actually some footnotes to the table. And I actually don't remember what the footnotes are.

MR. ALTOMARE: Okay. Thank you. And if you turn to slide 10, for LDC 3 the contributed capital was 215. Is that a typing error?

DR. CRONIN: No. I remember specifically typing that in. The contributed capital for that utility -- and it's not a small utility -- is 215 percent of the capital additions.

MR. ALTOMARE: If you turn to slide 13, where you're talking about SAIDI and looking over the five years and you're saying that the reliability is getting worse, did you give any attention to data accuracy? Because if I remember correctly, based on my experience and talking to several of the LDCs and looking at the industry, there wasn't a comfortable or, let's say, a consistent measuring of reliability in the industry. And I'm just wondering in the previous years whether we were understating, and then in the last two years we were reporting more, let's say, consistent with the definitions with what industry was acquiring.

DR. CRONIN: The baseline that we're comparing in this table is 2005 to 2007. So we're using 2005 to 2007 to set the benchmark.

And I guess I would -- I wouldn't believe that their collection of data would have changed so much in the five- or six-year period.

So we're reporting 2011 and benchmarking it against 2007.

MR. ALTOMARE: I understand that, but I would ask you to go back and take a look, because based on my experience, some of the utilities were having some difficulty understanding how you measure SAIDI in the calculation. So -- and it's not a reflection of the LDCs. It's really a reflection of companies in the industry being forced to do something or mandated to do something that they normally didn't do before. So there is a training process.

DR. CRONIN: The MEA collected and published reliability data in the early 1990s. So I actually have copies of the data they published from, I think, very broad-based responses, maybe hundreds of LDC –- hundreds of MEUs sending in data to the MEA.

So some of that have been at it for 20 years.

MR. ALTOMARE: I realize that, but I'll give you an example of the old Ontario Hydro in the '90s. We didn't include storms in our data, and that was quite a revelation when we started doing more rigorous reporting in the early 2000s, that people were making those comparisons and they weren't fair comparisons.

I just want to leave you with that.

Then the other thing I would like to just make a comment on is that I think what Dr. Cronin has demonstrated nicely is that if the process -- if -- hindsight is always great, but if the experts were brought in at the beginning I think we would probably be further along, because they all come with different views based on expertise, based on knowledge and skill set, that it would have helped us, as opposed to going this route. But it's just a comment.

MS. CONBOY: Thank you. Duly noted.
Dr. Cronin -- sorry, Dr. Kaufmann, and then Mr. Harper and Ms. Scott.
DR. KAUFMANN: Larry Kaufmann. Just a quick clarifying question on slide 9.
When you refer to "capital" there, is that capital expenditures?
DR. CRONIN: It's –– I'd have to double-check. It's been a month since I did this. It's capital additions, I believe, but I can actually --
DR. KAUFMANN: Capital additions?
DR. CRONIN: Yeah.
DR. KAUFMANN: But it's not capital stock?
DR. CRONIN: No. No, it's not capital stock.
DR. KAUFMANN: And in 2010, the capital additions would include, at least in part, smart meter expenditures, and they wouldn't have them in 2000?
DR. CRONIN: That I would have to check. I'm not sure how that was coded.
DR. KAUFMANN: That's it.
MS. CONBOY: Thank you. Mr. Harper?
MR. HARPER: Bill Harper for VECC. I would like to come back to our favourite, slide 10, again, if I could. It's more just some clarification questions and trying to reconcile some things in my mind.
This data comes from the yearbooks, does it, Dr. Cronin?
DR. CRONIN: No. Actually it comes from some broken-

out filings from the Board. It's not from the yearbooks.

MR. HARPER: It comes more from sort of the cost of service filings that utilities will be making in that year?

DR. CRONIN: I don't think it's the cost of service filings. I think it's part of the -- part of the PBR filings they do, but it includes more detailed data than what's codified in the yearbooks.

MR. HARPER: Because actually I was trying to reconcile the fact that we seem to have labour data here for capital, with the comment the Board made in its report that it couldn't do average TFPs because:

> “Distributors do not currently report information on a detailed level, and in particular information on labour cost shares has not been reported."

And what I seem to see here is information on labour cost shares, and this is what I was trying to reconcile, the two things in my mind.

DR. CRONIN: That's why this data -- this data was actually a request. We did a special information request and the Board broke that data out for us.

MS. CONBOY: Can you keep talking into the microphone?

DR. CRONIN: I'm sorry.

I believe that we made a special information request to the Board that they would were break out that data, and I believe that's how we got that data.

MR. HARPER: One other clarification question.

Are you aware of whether or not, when you say labour and overhead, you'd have different reporting of this if the utility was contracting out all of its capital construction to say an external contractor, in which case they would have no labour involved, as opposed to a utility that was doing most of the capital additions with internal staff, in which case there would be a substantial portion reported as labour? Do you have any idea whether that issue might be confounding the data that we see here?

DR. CRONIN: I don't.

MR. HARPER: Okay. Thanks. That's all I was trying to understand.

MS. CONBOY: Thank you. Ms. Scott?

MS. SCOTT: Jane Scott, Hydro Ottawa. I just had a couple questions on the line losses. So when you say include losses in TFP, so that's as an output, the loss as an input.

DR. CRONIN: It would be as an input.

MS. SCOTT: So the loss factor would be an input?

DR. CRONIN: No, that the -- it would be a similar calculation with capital/labour materials.

MS. SCOTT: And I guess it ties into then on slide 18, when you say "line losses are a substantial share of distribution costs", do you mean the cost to reduce line losses?

DR. CRONIN: No, if you look at the aggregate cost for a utility, including labour materials, capital, and you value that in monitoring terms, so you're looking at the expenditures as economists would look at them, then you can come up with a total expenditure by the utility.

If you look at what's the implied expense of line losses, they would come to as much as 20 percent of those costs.

MS. SCOTT: But understanding that they're not part of our service revenue. They're not part of our --

DR. CRONIN: Right.

MS. SCOTT: Okay. Just the way it was written. Okay. Thank you.

MS. CONBOY: I know your politeness would say, look at the person who is asking the question, but we'll have to --

DR. CRONIN: I'm sorry.

MS. CONBOY: No, that's okay. Are there any other questions in the room?

Okay. Ms. Chaplin, and then Lisa will say a few from the -- or read out the ones from the e-mail.

MS. CHAPLIN: So Dr. Cronin, I wanted to follow up on Mr. Shepherd's question about understanding the reasons behind the negative TFP trend.

So is it your view, based on what you do know -- and I take all the comments about the things that you feel should be examined. Is it a matter of, the TFP measurement is not capturing things which would show or demonstrate that in fact productivity and efficiency overall have improved, or is it in fact that productivity or efficiencies overall may well have declined, but we don't necessarily understand whether that's due exogenous effects of recessions and other things or due to the rate-making framework?

DR. CRONIN: We think that productivity has declined, and we think that it's -- it would decline more for those utilities that have had degradation and reliability or increase in line losses. So you would go from a negative to a more negative.

But going forward, if you were to have a more comprehensive indicator, so the TFP would include these other activities, that going forward, as they spent money, whether O&M or capital, and they made these improvements, besides producing power and supplying that, that more comprehensive measure of productivity would actually show a larger increase than just looking at, say, kilowatt hours versus capital and O&M.

So we think that productivity has been negative. We think that there may be a period whereby moving to more comprehensive measure it may seem as though it's getting more negative. That's why you have to look at these probably under a five-year framework.

But I think what our concern is, is that if you try to come up with, say, an X factor for an IR regime, that that should be reflective of the expected increase in efficiency, but the problem is, is that they are subject to all these other influences, like a recession, okay? And maybe we're beyond that now.

They had the IR incentives that change their choices for inputs, and we think that they were pushed into non-optimal combination of inputs which made them less productive.

Furthermore, some of them say -- and they've been saying it for a number of years -- that they have these, I'll call these super-normal -- super-normal demands on capital for infrastructure, modernization.

So you wouldn't want to reflect -- if in fact the infrastructure and modernization is really kind of beyond the ordinary means of business, you know, you wouldn't want to subject them to having to operate within those conditions with an X factor that doesn't reflect the fact that they need more capital than normal.

And there have been a number of jurisdictions in the States and I think even in Canada that, you know, that I'll call -- and they don't use this terminology, but that kind of move toward a K factor. And so the K factor was an old term for an adjustment for capital requirements that were sort of outside the normal bounds of the IR.

Now, these cases in Canada and the U.S. where they've been dealing with these problems of greater demands on infrastructure, they've come up with their own terminology, but in essence what they've done is they've reflected that outside of the I minus X, or they've tagged on some kind of revenue increase.

So I guess what I'm saying is, if you have to come up with an X factor, it needs to reflect the fact that they may have more demands than ordinary.

MS. CHAPLIN: And would our comparable be the ICM?

DR. CRONIN: I'm not sure.

MS. CHAPLIN: Sorry, incremental capital module.

DR. CRONIN: Well, I guess, you know, I'm not really -- I'm not really that familiar with what are the details there. You know, I think again it's all the details, and I think the one thing that maybe, you know, this peer group -- this peer-group benchmarking, you know, has been -- and capital in particular has been a thorn in the side of IR regimes for many years, and so it's a particularly difficult problem in normal circumstances. When you add in what people sort of around North America are saying is this abnormal period of infrastructure requirements, that makes it even more difficult.

MS. CHAPLIN: Thank you.

MS. CONBOY: Lisa?

MS. BRICKENDEN: Thank you, Paula.

We have a question from Shelley Grice, representing Association of Major Power Consumers, and it's related to Cynthia's questions to Dr. Cronin.

Shelley is asking Dr. Cronin: What additional analysis might be needed to better understand the negative productivity? What's involved in doing this type of analysis, and what time frame do you think might be needed to get this done?

DR. CRONIN: The analysis could be in part statistical, so, for example, what was the impact of the recession on TFP over that period of time, because you do tend to lose output as demand falls during recessions.

So I think part of it might be a time-series analysis. I think the more difficult, you know -- and maybe within that you could also look at these issues of non-optimal input selection.

So, you know, if the utilities are operating under more optimal input structures, what would their requirements be? And my guess is it would be -- because we've seen that they had a fall in efficiency, my guess is you would show a lower level of necessary cost.

The more difficult thing, I think, is this analysis of, how abnormal are these periods and the capital required now? What was the funding in the past? In other words, 30 or 40 years ago, where did the money come from to put it in the ground first? Okay. How much are they getting now from their revenue sources?

Now, I do know based on some analysis that we did that if you look at it in kind of a proportional sense the utilities are getting less for investment than they were 30 years ago, because more is being taken out in terms of dividends.

So the utilities actually are operating in a sense in a more difficult position now than they were 30 and 40 years ago. Because I don't think that 1st generation factored in, even though they adjusted for, you know, the capitalization and they adjusted for the taxes, I don't believe there was adjustments for these dividend payments to the shareholders.

So I think there would need to be this kind of historical analysis that tried to look at, how different is this period? Are the demands greater? Are the funding sources smaller than they used to be? And I guess I'm thinking it would take maybe six months.

MS. CONBOY: Thank you. Jay?

MR. SHEPHERD: I had a follow-up question on that, and on Ms. Chaplin's questions.

Tell me whether I'm right. I'm hearing you say that there's sort of three categories of reasons for TFP decline over the last decade or so.

One is a category of things like reliability, spending on reliability and other beneficial improvements that we would want to keep. We would want to keep that spending.

So that's simply unmeasured productivity, right?

DR. CRONIN: Yes.

MR. SHEPHERD: The second category is things that happened in the past data period that we don't expect to happen in the future, like the recession and stuff like that?

DR. CRONIN: And the non-optimal input choices.

MR. SHEPHERD: No, I'm getting to that.

DR. CRONIN: Yeah, okay.

MR. SHEPHERD: And the third is flaws in the previous IRM that incented the wrong things, and that if we identify those various reasons, then we'll have a better IRM going forward?

DR. CRONIN: Yes.

MR. SHEPHERD: Is that right?

DR. CRONIN: Yes.

MR. SHEPHERD: Thanks.

MS. HARE: I have one final question. You did make comments about the Board's benchmarking and perhaps rewarding the inefficient and penalizing the efficient, but do you have any comments on the Board's proposal to have five stretch factors ranging from zero to 0.6?

DR. CRONIN: I guess I would probably warn against the whole issue of stretch factoring and benchmarking, given all the problems that we have in identifying who is efficient and who isn't. So I think -- I think it would be much better for all the stakeholders in the province if we could identify these sort of basic issues about what impacted the –- the history, what can we change going forward, and kind of what's the right level of expected productivity improvements. Given all of these problems, like, do they need more capital?

And I would rather focus on that, and less on trying to sort out who is less efficient in an environment where the data may not be up to doing that.

MS. HARE: Thank you.

MS. CONBOY: Go ahead, Carm.

MR. ALTOMARE: Thank you. I have one final question, and it follows a question from AMPCO and also Jay Shepherd.

And not that I'm trying to solve it and trying to help you, Dr. Cronin, but when you talk about efficiency in today's world and, I would say, going back over the last few years, isn't the argument more on effectiveness as opposed to efficiency?

I'll give you an example. Distribution is driven very heavily by reliability, but also customer sat, and customer sat, I mean the services, customer services. And we have SQRs that we're diligently following through, meeting the OEB requirements.

So that, I think, should be included in the inputs somehow. And it ties into looking at performance more in a balanced approach, because that will explain, probably, the negative productivity, because the inputs that we have may not be totally conclusive. And by that, I mean even the CDM program, the DGs that we connect. They impact on losses, they impact on the peak, and also they impact on customer service.

So I just offer that, in going forward, if you're doing this analysis, that we should be looking at more of a balanced performance as opposed to just efficiency and cost.

MS. CONBOY: Thank you.

DR. CRONIN: On page 5, the very first comment we made about objectives was to be customer-centric. So I think we would totally agree with you.

In my terminology, what we're saying is that the measure should be more comprehensive. They should look at things that affect the consumer, whether it's their cost or their service. So we're arguing, you know: Include reliability, include line losses.

There's probably a limit to what you can do in an economic incentive framework, and I guess we would argue: Don't put so many things into the objective that they lose sight of what's really important. So maybe as side initiatives they would have these other things, but we're totally in agreement with the issue of the customer-centric nature.

And to the extent that there are improvements in things that are not reflected, like if line losses did improve or reliability was made better, if those are not incorporated into TFP, then you're understating the improvement that the utilities made.

MS. CONBOY: Thank you. We're going to break now for 20 minutes. Come back at 11:30, and we will hear from Prof. Yatchew.

--- Recess taken at 11:09 a.m.

--- On resuming at 11:35 a.m.

MS. CONBOY: Can we resume, please?

Actually, if you'll give us a few minutes, we just need to take a break.

--- Pause in proceedings.

MS. CONBOY: Okay. So let's continue. Prof. Yatchew has a presentation, and I think if I look across, it seems that everybody has copies of, so if you want to get started, Prof. Yatchew.

PRESENTATION BY PROF. YATCHEW, ELECTRICITY DISTRIBUTORS' ASSOCIATION: 4TH GENERATION INCENTIVE REGULATION OF ONTARIO'S ELECTRICITY DISTRIBUTORS

PROF. YATCHEW: Thank you. Let me begin with the inflation factor. I'm sure that the Board Staff and the Board struggled with this consideration, trying to determine what the right inflation factor is. Here we've talked about using inflation factors that more closely track the heavily -- the capital intensive industry more closely.

I think that in present circumstances staying with a broader inflation measure that is not as volatile is the more reasonable option. It's certainly better understood in the stakeholder community. There are risks to it. Dr. Cronin mentioned some of those risks, and I will return to this a little bit later.

Productivity trends. In our earlier report we estimated the productivity factor using two methodologies. We used an index-based approach and a cost-based approach. The estimates were approximately minus .7 percent, minus .8 percent respectively, indicating significant upward cost pressures in the industry.

This has been the source of considerable attention throughout this proceeding and certainly earlier today. We've had a preliminary look at the updated data, which includes the year 2012, and our estimates are slightly more negative than they were before, but not very much -- to a very large degree.

We remain of the view that the econometric approach has characteristics superior to the pure index-based approach, primarily because the econometric model is needed to begin with in order to calculate productivity trends via the index approach, and also because it permits identification of the components of productivity changes.

We do have concerns about the exclusion of the two largest distributors from the data on the basis that they are outliers. The analysis does include utilities with even minor disparities, in terms of size. So in my view, in having worked with the data directly, I think it's more sensible to include these two observations in the analysis.

I'm not going to get into the technical details of the index-based approach that weights utilities by their size rather than simply as individual points. I appreciate that that's one of the rationales for excluding these two observations.

In that kind of analysis, in my mind it's also an argument for a different type of analysis more closely along the lines of what we did in our report.

Peer-group analysis. We support the Board's decision to set aside this approach at the present time. I think in its proposed form it is contentious and likely to contribute productively to the assignment of distributors to efficiency cohorts.

Relative efficiency. A point that's been made repeatedly -- Dr. Cronin made this earlier today. I'm sure it will be reiterated again later on -- the estimation of relative efficiencies, it's difficult and subject to considerable risk of misclassification. Even relatively minor model variations can lead to migration of distributors from one efficiency cohort to another.

Among the available alternatives, the cost model provides a better indicator of relative efficiency, though even this model can lead to anomalous results for some distributors.

And the examples we were working with the data were excluding a completely statistically and significant variable caused a utility, its relative efficiency to change very dramatically for certain individual utilities.

We think it's appropriate to use five groups in the assignment of what are called stretch factors, as determined by the benchmarking model. In the past we've put forth arguments that the stretch factors should be centred as zero, with negative values assigned to relatively efficient firms. That's because we don't really think of these as stretch factors, but simply factors that allow for differentiation amongst utilities.

We understand that the Board does not believe negative stretch factors to be appropriate. However, where there may be -- it may be given -- it may be worth giving further consideration to how the dividing lines are set between groups.

And my concern is, for example, if you look at the group that receives the -- that is currently being assigned the highest stretch factor, there are rather large disparities in the estimated efficiencies within this single group, ranging from 16 percent roughly above predicted costs all the way up to in excess of 70 percent of accepted costs.

And my current view is not to increase the number of groupings, but rather to draw the lines in a different place, perhaps at a higher point. I don't have a definitive view of where that line would be drawn just yet, but we will have -- we will include that in our final comments towards the end of the month.

In our report back in June we talked about the possibility of incentive schemes that base stretch factors, or these individualized productivity factors, not only on relative -- not only on the performance relative to others, but on their performance relative to themselves over time, have they been improving.

I appreciate that that's a relatively new idea. We gave some sports analogies in our paper. And we do appreciate that the Board appears to be willing at least to give us consideration going forward.

So the numbers. Inflation factor -- this is from the Board's report of 1.6 percent for 2013. A productivity factor of zero, and this is -- even though the estimated productivity factors are negative, ranging from Dr. Kaufmann's values of around minus .3 to our values of around minus .8, stretch factors ranging from zero to .6 percent, which would at the end of the day result in a rate increase of about 1.3 percent for, let's say, a median utility.

And that wouldn't seem very reasonable. However, there are risks to the calibration of a regulatory rule that can distort incentives in the following ways. The first one is, if you set the overall increase too low, then there's a potential for delay.

And maintenance we've heard about. There is the potential for distortions between OM&A capital decisions. So especially when one is coming to a point where the decision isn't clear whether one should refurbish or whether costs should be entering into, whether this should be an OM&A expenditure or capital expenditure, it may be that there will be distortions there if insufficient funds are available on the sort of operating-cost side.

It can even influence the portfolio mix. So the bottom line might be, say -- might be, let's say, 1.3 percent --

MS. CONBOY: Prof. Yatchew, can you speak a bit more into the microphone so the court reporter can get it?

PROF. YATCHEW: Sure. Thank you.

Let's say the bottom line is 1.3 or 1.5 percent, just to pick a number, consisting of a higher inflation factor at the moment and a lower -- or let's say a more restrictive productivity factor than are reflected in the data. And suppose that, going forward, interest rates begin to rise. The utility, recognizing that they will not be compensated for or covered off on increase in interest costs, may end up trying to go long just to hedge that risk. And it's a regulatory risk they're hedging, not a financial market risk that they're hedging.

So this is a consequence of the regulatory rule, rather than an optimal portfolio mix-type decision. So there is that risk.

And historically -- and I'm not saying that's the case today, but historically there have also been -- regulatory decisions have certainly influenced accounting practices, if we go back over the years, in terms of allocation between current and future costs.

So I do see risks.

Overall, I think that we do need to recognize that this productivity factor has been consistently negative in the estimates. I'm not optimistic that we'll be able to uncover the sources and the causes of that negative productivity factor with the data that we have now.

And I realize that some of the factors that have been raised would appear to be one-time event, but again I would point to the experience, to the big-picture experience in other jurisdictions that have had aggressive renewables programs or ambitious renewables programs.

There has been substantial pressure on rates, not in just the generation segment of the industry but also in the wire segments of the industry.

Those are my comments for now. Thank you.

Q&A SESSION

MS. HARE: I did just want to pursue the last issue that you raised, that you're not optimistic that we'll be able to understand the causes of the negative productivity factor in the near term.

Would you disagree with what Dr. Cronin said earlier today, which was basically: Take six months to investigate this further?

DR. YATCHEW: First of all, we, as in Dr. Cronin and certainly Dr. Kaufmann, more than anyone in this room, have worked with the data in great detail. And I have great respect for my colleagues.

And Larry, being an empirical economist, would have sought those explanations if they were available in the data. It's publishable.

So without having myself tried to find what the right explanatory variables are, I sort of on a –- this is my subjective judgment, admittedly, but my judgment is that I think that if Larry couldn't find those in the data, they're not going to be found very easily.

I'm open to persuasion otherwise, but that's -- based the information that I have and the data that I have seen, I don't see that as being very promising at this point.

MS. HARE: Thank you.

DR. YATCHEW: Can I just add one more?

Going forward, that's another matter. Ten years ago Dr. Cronin kept saying that we need capital data, we need capital data, and he kept pushing on that. And eventually we got reasonable capital data, so there has been huge progress in that.

And I think, going forward, progress can be made in trying to allocate sources of productivity growth, positive or negative. I'm just not seeing it in the current data that we have.

MS. HARE: Thank you.

MS. CONBOY: Are there any other questions of Prof. Yatchew? Jay?

MR. SHEPHERD: I just have one. On slide 5, Adonis, you had a comment -- if I can find it -- that suggests that even without Toronto Hydro and Hydro One, there are still wide size disparities between the utilities that are left in the sample.

And I guess I thought that the reason, the Board's rationale for excluding Toronto Hydro and Hydro One was not size disparities, but rather their dominance in the data, and that without them, nobody else is dominant in the data; isn't that right?

DR. YATCHEW: In doing the index-based calculation that assigns rates to utilities based on their size, that's a true statement.

But if you assign equal weight to all utilities in the --

MR. SHEPHERD: So if you use simple averages instead of weighted averages; right?

DR. YATCHEW: Correct.

MR. SHEPHERD: Okay. Thanks.

MS. CONBOY: Bill?

MR. HARPER: Bill Harper. I'd like to go to slide 7 and just a clarification here, Dr. Yatchew.

You were talking about among the available alternatives, the cost model provides the better indicator. I just want to be clear.

In terms of available indicators, you're talking about things like the peer group analysis or the DEA analysis that Dr. Cronin was referring to?

DR. YATCHEW: Yes.
MR. HARPER: Because I guess what we've seen here, we've seen -- last time around, we have four experts and actually we had four cost models. So when you say "cost model", you're talking about -- at a very generic level, you're talking about cost models, as opposed to any specific cost model?
DR. YATCHEW: Yes. I'm happy to elaborate on that.
MR. HARPER: No. I think last time we had considerable debate over the merits of different cost models. I just wanted to make sure that it was at a high level we're talking about cost model in principle is better than other approaches.
DR. YATCHEW: Yes.
MR. HARPER: Thanks.
DR. YATCHEW: By the way, it's not to say that DEA analysis can't inform assessments in various models. Various specifications of similar models actually help us understand how much variation there is in these allocations to stretch factor groups.
But overall, I think that this kind of admittedly technical analysis, econometric analysis, is the most comprehensive at this point.
MS. CONBOY: Thank you.
Lisa, have you got any -- okay.
Well, thank you very much. Who have we got next? Is it Mr. Fenrick up next?
Thank you for participating, Prof. Yatchew. I

understand you have to leave for the rest of the day. Thank you.

We're ready when you are.

PRESENTATION BY MR. FENRICK, COALITION OF LARGE DISTRIBUTORS:

MR. FENRICK: Thank you for allowing us to come and speak here. I'm Steve Fenrick, an expert witness on behalf of the Coalition of Large Distributors.

Just a kind of a clarifying, upfront statement is, you know, we haven't been able to, given the time constraints, actually verify PEG's or Larry's latest models and the findings there. So I just want to put that upfront. We've really had limited review, given the time constraints.

So my presentation doesn't really necessarily validate what they've come up with. In their prior iteration, we were able to validate most of their findings. So given that and given some of the changes made as far as some data with 2012 and some of the method changes that appear to be there, we haven't had a chance to look at those things and see how they impact TFP in their benchmarking model.

Some things that I would like to respond and comment on that were found in the Board's draft is the two-factor IPI proposal, the productivity factor being equal and set to zero, the stretch factors and how those look, the elimination of peer grouping in the stretch factor calibration, and solely depending on a cost model or econometric model and then the PEG's -- using PEG's model for that calibration of the stretch factors.

So on the inflation factor, I certainly believe that the two-factor IPI as put forth is certainly an improvement. It's going to track costs in a better and more appropriate way than the original PEG recommendation. There's going to be far less volatility, which has been shown, likely better tracking of actual distributor cost pressures. Given PEG's recommendation that had that large negative, I don't think many distributors -- I don't want to speak for distributors across Ontario, but I don't think many felt that that was a very good tracking of their inflation pressures. And then there is no need for the smoothing, with the 2-factor inflation measure. So that's -- those are all positives that we think is certainly an improvement.

You know, the 2-factor IPI still does not incorporate the capital asset inflation into the measurement. In the recommendation we put forth back in June, I believe it was, we basically put forth the 3-factor IPI, kind of the same two components of the 2-factor IPI put forth here, and then also adding the EUCPI to track capital asset and inflation.

And we still think that would be a better measure. It would incorporate -- you know, capital is about 50 percent, you know, and give and take 40 to 60 percent of distributor costs, and we think including that asset price inflation into the inflation measure will better track distributor inflation measures.

And the EUCPI is already tracked, it's already published, and it's a simple weighted average to insert that, so we don't think it would make it too onerous to add that into the inflation measure. And you still don't lose -- the volatility is going to be about the same as the 2-factors. You don't lose much, but a better tracking for pretty low -- low effort and not much additional complexity.

Another consideration -- the first one I just talked about there. Number two is, in the Board's draft report they mention just updating the IPI one time, so essentially for January 1st filers, say they're filing for two-15, two-15 rate year, you're going to be using the two-12 to two-13 inflation.

One recommendation or suggestion might be just to update that on a more up-to-date basis, especially the components that are reported quarterly. For instance, use average weekly earnings. I don't -- I think those are only annual, if I'm not mistaken.

But the GDP-IPI is updated quarterly, and I think it would be more contemporary and up-to-date to at least update that component to get a more up-to-date measure of the IPI.

Moving to the productivity factor, you know, the 2002 through 2012 TFP has been measured to be negative. All four experts appear to agree that over this time period it has been negative.

You know, PEG in their recent report that came out on Friday measured minus .33 percent TFP, and that's even after excluding Hydro One and Toronto Hydro, and obviously that's a much larger negative if the full industry is used.

And even at the more recent TFP historical period, TFP has even decelerated further. In the PEG report, or PEG 2012 update, they have a TFP measure of negative 1.28 percent over the 2006 through 2012 period, so we're certainly seeing negative TFP in the industry. It seems like all the experts do agree with that, and it seems to be accelerating. It's becoming more pronounced as time goes by.

And I should mention, you know, that negative .33 percent that they came up with, that's even after excluding only the negative -- only negative large outliers and doing some things which, we haven't been able to kind of tease out or figure out the methods here yet, but as far as looking at smart meter and expenses and taking -- stripping some of those expenses out.

Regarding the econometric model and how that applies to TFP, which has been discussion on -- on that, the trend variable in the econometric model is now 1.98 percent, which is essentially saying costs in the province have been going up by over 2 percent above inflation and output growth, and there's other things you would expect to increase costs. Unit costs are still going up by 2 percent above all those other factors.

I should mention too, in our -- in other research we've done on the U.S. industry, TFP is telling a similar story. It has been declining over time as well. You know, Ontario, I don't think is necessarily isolated in this experience.

The U.S. has also had declining TFP, and we're actually finding now where it's negative, just like Ontario. And so, you know, yeah, there are some things that make Ontario unique as far as maybe the CDM programs and then some data, those types of things, but there's also just factors in the industry, cost pressures, and I think expectations on utilities that have been increasing, in as far as customer service and reliability and all these things that even Dr. Cronin mentioned in his presentation, that have been putting more and more cost pressures on utilities. And in the U.S. experience that's also the case, where we're seeing negative productivity.

And if we assume these cost pressures aren't going to go away anytime soon, if this is the experience, if this is the age that we're living in, as far as aging infrastructure, higher demands for reliability, you know, green initiatives and these types of things, you know, we're going to -- distributors are going to experience cost pressures that are above and beyond a productivity factor set at zero.

And so I kind of see a productivity factor of zero as kind of containing an implicit stretch factor. You know, all the experts have found negative productivity growth that's been the experience throughout the industry for over a decade now. And so there appears to be sort of an implicit stretch factor contained within a productivity factor set at zero.

Which moves us to the stretch factor. As I mentioned, I believe that it should be recognized that there is an implicit stretch factor included in a productivity factor set at zero. Considering all the empirical evidence and all the data-churning that's been going on, that certainly does appear to be the case.

You know, PEG is estimating -- they see that shortfall between a zero productivity and actual productivity at .33 percent. You know, we believe it's a little larger than that, as do the other two experts, but, you know -- so we think there is an implicit stretch factor of at least, at a minimum, of .33 percent implicit within the productivity factor set at zero.

And that, put on top of the explicit stretch factor, which -- as put forth by the draft report, the Board's draft report puts forth a stretch factor of .37 percent. So you kind of combine those two and you have a kind of average stretch factor of .7 percent, with a range of .33 to .93 percent.

This is quite a demanding challenge for distributors to exceed productivity growth by over .7 percent simply to maintain their allowed ROE and kind of stay on the rate course that they want.

This is going to be a demanding stretch factor, and I think it's kind of beyond what is normally seen within incentive regulation and performance-based regulation plans.

Moving to kind of determination of the tranches that appear -- the groupings that set the stretch factors. The Board report put forth a method of kind of separating the different groups based on the cost score in the econometric model. And you kind of see the five different tranches and how they're set, with tranche one being, if you have a cost score that's 20 percent below what the benchmark value is. Moving on, tranche five being if you are greater than 15 percent.

I think this -- one way to kind of look at this is it does make setting the groups vulnerable to how good the model is. A model that contains more variants is going to have more distributors in tranche one and tranche five than a really tight model that maybe in some respects can be thought of as a more accurate, robust model, is going to have a tighter range, in which case you'd have less distributors in tranche one and five.

And so I think what would make a little bit more sense would be simply basing the tranches on the rankings that come out of the econometric model.

Just looking at the quintiles, breaking in industry, I'm ranking them from 1 to 73 or whatever the number happens to be at the time, divided by five, and then, you know, tranche one is the top quintile, tranche two is the second quintile. That way you're not going to be vulnerable to model changes. If the model gets better or worse, you know, the distribution between tranche one, two, three, four, and five won't be changing on an annual basis. It's going to be set based on the quintile rankings.

This slide basically says exactly what I just said. We'll move on.

As far as elimination of the peer groups, highly supportive of this proposal. You know, we think the peer group method is inferior to econometric benchmarking simply because it ignored, completely ignored crucial information. And as far as the different variable values of distributors, all that information was kind of lost in the analysis.

It made the process more complex to have two methods, with the peer group approach basically depending on the econometric method to begin with it; it just made the process more complex, and needlessly so. It wasn't really adding any new information to the table. And just the existence of it hampered distributors' ability to move. Having one method to set the peer groups or to set the cohorts is going to basically enhance the ability to -- for distributors to move.

As far as what model to use in setting the stretch factors in the tranches and those types of things, the draft report states the use of PEG's econometric model.

In our report, our expert report in June, we put forth what we call the unit cost econometric model, where we looked at the cost per customer and then created a benchmark based on a whole host of external business conditions, to determine what should each distributor's unit cost benchmark be.

The Board, in its report, cited two concerns. And if

I could just kind of address those two concerns of the benchmarking model that we put forth, the first one is that it assumes a linear relationship, that our model assumes a linear relationship between business conditions and costs. So that is kind of the first concern.

And the second concern was that it assumes constant returns of scale in its assumptions.

There's the model, if anyone wants to -– I just thought I'd insert a slide there with the model put in there. And you can see the cost per customer has essentially been explained by all these business condition variables.

You see everything is -- the T statistics are all statistically significant in here, and you have a number of business conditions.

So going back to the two concerns that the Board put forward forth in its draft report, concern number one of the PSE model was that the linear relationship is assumed. That was the case when I came to present here at the last stakeholder conference. Given Dr. Kaufmann's comments and Dr. Yatchew's comments, I didn't want that to be a stumbling block, and it really didn't change things all that much. We actually went away from the linear relationship and assumed a log-log relationship, which is the same assumption that PEG makes in their econometric model.

So that was basically in response to that, those comments. And so we no longer in the report, the reported model, we actually don't have a linear relationship anymore. It's a logarithmic, log-log relationship.

Concern number two is regarding the constant returns of scale assumption, which that is true; there is a constant returns of scale assumption in our unit cost, the econometric model. And what does that assumption mean?

What it means is that as output goes up by one percent, the model assumes that costs will go up by one per percent. So there would be kind of a 1:1 relationship between outputs increasing and costs increasing.

Ironically, this is very similar to the assumption of TFP growth equalling zero. You know, TFP growth is essentially saying as inputs or as costs go up by one percent, outputs are expected to go up by that same percent. And so TFP growth equalling zero essentially includes an assumption that, as inputs increase by one percent, output increases by one percent, very similar to the assumption that we're making here in our model.

And kind of comparing to PEG's model, PEG's model stays flexible on this assumption. It's not making a constant returns of scale assumption. It remains flexible on this, which maybe could be okay if all distributors were similarly sized.

But in the province of Ontario, we have distributors that are 5,000 customers to 100,000 to 700,000 to one million. A Hydro Ottawa is far different than Renfrew Hydro. And staying flexible on this, while it sounds like a good thing initially, if you actually dig into the model, it leads to obviously wrong underlying assumptions, far worse, I would maintain, than the constant returns of scale assumption that we're making.

Our model, the PSE model, is essentially --

MS. CONBOY: Sorry, Mr. Fenrick, can you walk me through that one more time? Because I guess it's not obviously wrong to me, but if you could repeat your explanation of the translog cost function remaining flexible on the assumption?

MR. FENRICK: Sure. So in PEG's model they have what's called a translog cost function, and the advantage of a translog cost function is it doesn't presuppose any sort of return of scale assumption, and it remains flexible.

So one distributor might have a returns of scale assumption of one value, and another distributor's going to have a completely different value given to it, because given all the quadratics and interaction terms -- if you look at PEG's report, they have all those quadratic and interaction terms.

MS. CONBOY: But it's whatever their data says, constant, diminishing, increasing, whatever -- it's whatever...

MR. FENRICK: Exactly. Now, with the caveat that model is estimating at the mean of the data. So translog cost function is estimating what those values are at the mean of the data.

So my earlier statement, where the translog cost function might be appropriate if the province had very similar distributors in size, because it -- it's coming up with estimates at the mean of the data. We're at the mean of, what, 35,000 customers, about, give or take.

If we're looking at distributors that are on the -- very small or very large, those estimates are going to be more and more inaccurate.

And that's kind of in the literature on translog cost functions. As you move away from the mean, you're going to get more and more inaccurate estimates.

So that -- it's saying what the data is saying at the mean, but that becomes more and more inaccurate as we move away from that mean.

Does that help answer your question?

MS. CONBOY: And because we have such a heterogeneous industry, you do need to take that into account?

MR. FENRICK: Right. And I kind of walk through some of the wrong -- I think I can make the statement that the results that come from remaining flexible lead to just wrong –- economically, obviously wrong -- values for returns of scale, because of -- like, you mentioned the diversity of distributors in the province.

You know, it's just impossible to make a translog cost function model be right for all the distributors. I would maintain you need to make an assumption on what the returns of scale be to have a properly functioning model. And I think constant returns of scale is as good an assumption as you can make, and it aligns itself with a productivity factor of zero.

MS. CONBOY: Thank you.

MR. FENRICK: Just some examples on an extreme end.

As I mentioned, the PEG remaining flexible, the translog cost function in PEG's model remains flexible, so each distributor is going to have its own underlying returns of scale assumptions. And that is coming from the data of what they're estimating.

So, for instance, Hydro One, the cost elasticity of customers, we calculated this at -- for PEG's model, at negative 0.514 percent –- or negative 0.514 is the coefficient.

So what is that saying? That's saying as customers go up by one percent, PEG's model assumes that Hydro One's costs will go down by 0.5 percent.

You know, customers go up, normally we would think costs would increase as customers go up. The underlying flexibility of PEG's model makes it such that Hydro One's benchmark would actually drop by 0.5 percent if they increase customers by one percent, which simply violates common sense and economic theory.

On the other extreme, Hearst Power has a value of cost elasticity of customers of 1.366. So that's saying as customers increase by one percent, costs are predicted to increase by 1.366 percent.

So two extremely different values coming out of there, and there's a whole spectrum of values that the distributors have. So that's their assumption of the cost elasticity of customers.

I also include Wasaga Distribution's cost elasticity and that's about zero. Customers increase by one percent, costs really aren't expected to increase much. It's 0.045 percent.

So those are the underlying assumptions. Contrasting that to the PSE model for all distributors, our model essentially says as outputs increase by one percent, costs increase by one percent.

So that that's the assumption, the constant returns-to-scale assumption, compared to kind of what's implicit in PEG's model.

Some more examples, as far as peak demand and other outputs in the model, in PEG's model it is peak demand. For instance, Wellington North, they have a value that implies that if peak demand goes up by 1 percent costs would actually drop by .297 percent. Again, that's by the economic theory that as output goes up costs would go down. Same thing, Sioux Lookout Hydro: on kilowatt-hour sales, as predicted, as that goes up new costs are expected to drop.

You know, and these aren't necessarily isolated examples. I kind of pulled out some of the extremes. But 32 out of 73 distributors have negative returns to peak demand in the model, so -- and that violates economic theory. That's what the data is saying, but the data is just unable to accommodate the diversity of Ontario's distribution industry. 15 out of 73 distributors have negative returns to the kilowatt-hour sales in the model.

So kind of the advantages I would kind of make -- argue with some of the advantages of the PSE model over PEG's. I think one of the advantages is the constant returns-to-scale assumption. You know, it in no way violates economic theory, nor kind of intuition. And it treats all distributors equally. You don't have these extreme differences in how increasing customers impacts one distributor versus the other distributors.

Our model also just includes more statistically significant business conditions. The PEG model has six external business conditions that's including in the benchmark and essentially adjusting for -- our model has ten. So we're adjusting for more things, accounting for more differences in the service territories, than the PEG model.

And how are we able to do that? Essentially because of that constant returns-of-scale assumption, we're saving a lot of degrees of freedom and basically power up the model, and we're using that towards basic correcting for the differences between distributors, which we think is a huge advantage of the model.

And there is no insignificant business conditions included in the PSE model, whereas the PEG model does have two business conditions that are statistically insignificant that are included in the model, the percent service area and the percent lines underground, but then you also see all those quadratic and interaction terms in the PEG model, and a number of those are also insignificant, whereas our model doesn't suffer from insignificant variables.

A summary of what I talked about. The 2-factor IPI is certainly superior to the prior recommendation. And we think it could easily be further enhanced by including a weighted average of the EUCPI without limited effort.

Productivity factor of zero is not necessarily reflective of the historic experience of Ontario. It's not reflective of kind of the U.S. experience either, what we're finding. So essentially if that is set at zero, it does kind of embody an implicit stretch factor within it that's going to make it more challenging for distributors to hit the target, the allowed rate increase.

We think stretch-factor calibration and how -- setting those tranches can be improved by using the rank rather than the score. The score is dependent on the model that you use, and the distribution could change over time depending on changes, whereas the rank, the distribution will stay set, unless, you know, they'll be top 20 percent in tranche one, second in tranche two, et cetera, and that's not going to change kind of on an annual basis.

We think the Board perhaps could consider reducing the stretch factor in recognition of the implicit stretch factor that's already accounted for in a productivity factor of zero. You know, even if one goes with PEG's estimate of .33 percent on negative productivity growth, perhaps, you know, the top end could at least be reduced to account for that or in some way recognize the implicit stretch factor that's there.

And as we talked about previously, we believe our unit-cost econometric model is better and just a more intuitive model, and it accounts for more things, more service-territory conditions, has more statistically significant variables. It does not contain insignificant variables. It is just a better measure for benchmarking purposes of determining cost efficiency for the distributors.

Thank you.

MS. CONBOY: Thank you.

Q&A SESSION

MS. HARE: I have a very easy question to start with on page 9, your last bullet, when you say "dividing the industry into quintiles based on ranking would be simpler in ensuring equal distribution that does not change over time". You're not suggesting that the same stretch factor applies to that distributor for the five years, are you?

MR. FENRICK: No.

MS. HARE: You're saying the method stays the same.

MR. FENRICK: Correct. Right.

MS. HARE: And on that same topic then you would -- there was a proposal in the earlier comments that ranked them 1 to 73, but the stretch factor then changed for each one from 1 to 73, but that's not what you're saying. You're saying the first 14 would get zero, the next 14 would get .15, et cetera? That's what you're saying?

MR. FENRICK: That is what I'm saying. Now, that idea of changing them, you know, I think that has some merit too, because, you know, if you base it on the rank, so kind of go 1 through 73, and in some way calibrate that stretch factor in that, that would enhance the ability to move, obviously -- just move one rank, and you're going to change your stretch factor in that way, and the distribution would stay constant.

So, you know, that would -- I wouldn't -- certainly wouldn't be opposed to that either, but...

MS. HARE: My last question is about the inflation factor, and that's, with the inclusion of your third factor for capital, how volatile is the result then?

MR. FENRICK: I believe at the stakeholder conference -- was that back in May? I looked at that, as far as the standard deviation in the 3-factor that we put forth versus -- and compared to the GDP-IPI, and it had the same standard deviation, the same volatility, so it's kind of equal volatility to the GDP-IPI.

Now, I haven't looked at the 2-factor. I assume it's going to be very, very similar in regards to volatility compared to the 2-factor.

MS. HARE: You might consider looking at that when you're putting in your written submissions.

MR. FENRICK: Very well.

MS. HARE: Thank you.

MS. CONBOY: Are there any other questions or comments for Mr. Fenrick? Go ahead, Jay.

MR. SHEPHERD: I have just one, which is probably in two parts. On slide 5, which is on page 3 of the material I have, you talk about -- sorry, slide 6, my apologies -- you talk about the more recent TFP being even more negative.

Is the implication of that, or is the possible explanation of that, that this is the result of or sort of an artefact of the design of second- and 3rd generation IRM, what Mr. Cronin was saying -- or Dr. Cronin was saying, that maybe there were flaws in the past IRM that resulted in the wrong things being incented and TFP being less positive as a result? Is that a possible explanation?

MR. FENRICK: That's possible. Without actually investigating -- and I'm probably more in the camp of Adonis. I'm not sure if we can actually get to those answers with the historical data that we have.

But I would say this aligns with the experience of the U.S. industry as well. More recently, its productivity has also been dropping, and so, you know, while possible, you know, maybe some flaws in prior IRMs maybe are to blame, that's hard to say with any sort of certainty, but I would say this decline in -- this accelerating decline is also seen in the U.S. industry, and they're generally under cost of service for most of the utilities there.

And so I would -- without actually having a definitive answer for you, I would lean towards saying no. I think it's more an artefact of just more demands being put on distributors over time, you know, better customer service, reliability, an ageing infrastructure issue, that's just kind of, in a way, generic across North America, from what we're seeing.

MR. SHEPHERD: Okay. And then the second part of the question is, in the private sector, if you have relatively high increases in costs over a period of time, you generally assume that your cost pressures are then going down in the subsequent period, because you've already spent a lot of money to make things better and to -- you know, you've already answered some of your pressures.

Is that a reasonable conclusion in this case too, that, going forward, the productivity should be less negative, we should expect that?

MR. FENRICK: I don't know what we should necessarily expect. I think it's certainly the hope that productivity is going to become less negative, or ideally it would become positive moving forward. But I think it's -- given the data in the historical experience that we're seeing, there is no evidence to claim that or to expect that 2014, '15, '16, '17 we're going to see a turnaround from this somewhat dramatic trend of negative TFP growth that is accelerating.

Now, as an economist, I would love to see that turnaround. That would be better for everyone. But I don't see the cost pressures necessarily going away as far as the, you know, Green initiatives and aging infrastructure and kind of the cost pressures that maybe are causing this deceleration in TFP. I don't see that abating any time soon.

And maybe at some point in the long run, certainly we should not -- in 20 years or 30 years or whatever it might be, negative productivity growth should not be the case, but in the era that we're in, I don't think we necessarily have any reason to believe that's going to turn around in the next five years.

MS. CONBOY: Go ahead, Richard.

MR. STEPHENSON: Thanks.

I want to just explore with you for a moment this issue about the absence of the third factor on the inflation measure, and in particular, figure out from your perspective the probable materiality of the non-inclusion of that factor.

If we're talking about a five-year IRM period and if we're talking about the next five years, and if we make some assumption that the interest rates during the next five years are going to be, to some extent, higher than they have been in the last five years -- and I appreciate the order of magnitude of higher will affect your answer, but let me just ask the first question first.

Am I right that if interest rates are higher in the next five years, then there will be a tendency to under-recover if a capital inflation measure is not included? Generally speaking, is that right?

MR. FENRICK: Yes, certainly that's true.

Now, the capital measure I'm putting forth, that does not include interest rates. For better or worse, given there is just no easy way to put that in there without making it extremely volatile.

So you are correct that if we assume interest rates are going to increase over the next five years, that's going to put added pressure on the distributors beyond this "I – X" equation. If interest rates are not in there, which -- they're not explicitly with the 2-factor or the 3-factor that I'm proposing, interest rates are not explicitly in there –– now, implicitly I think we could expect interest rates to follow the same trend as inflation.

Implicitly, I think interest rates are somewhat in that inflation factor, but maybe not explicitly, and I think that will put added pressures on the distributors, where they are going to have to be paying higher interest rates. And the inflation factor is not necessarily going to follow that trend.

MS. CONBOY: Okay.

MR. STEPHENSON: Let me come to the second part. And I appreciate this will all depend upon what assumptions you make, but if there's -- to the extent that there is a risk of under-recovery in those circumstances, if it's going to be a small amount of under-recovery, relatively speaking, maybe nobody cares about it and it's not worth getting into. But if there is a material risk of a very substantial under-recovery, then maybe this is a real problem. And I just want to get a sense from you, to what extent is the risk of -- is this a small amount or is it a big amount? To what extent do we have to really worry about it?

MR. FENRICK: Yeah, I think that's a good question. Adonis has discussed kind of what the 2-factor inflation minus productivity of zero, and then with the stretch factor, basically, so a 1.3 percent increase in 2013.

Now, the historical unit costs for distributors have been increasing. I can't think of the number offhand, but it's but well in excess of three percent.

So the under-recovery, if the experience continues on like it has historically, there is going to be a large under-recovery with the current setup.

Add to that the fact that that three percent or so that unit costs have been increasing from -- by distributors has occurred in a time in declining interest rates or at least flat interest rates. And now if we're entering a time of increasing interest rates, those cost pressures are even going to be higher on distributors.

There is a large potential, unless productivity makes a huge unexpected change, there is a huge potential and almost a certainty that there is going to be a large under-recovery, given the current parameters that are set.

MS. CONBOY: Thank you.

Larry and then Bill and Mike.

DR. SCHWARTZ: Thank you. Larry Schwartz, Energy Probe. If I could ask, I think, a fairly easy question, easy-to-answer question on page 8, PEG's returns to scale results, there's a relatively small point that interests me.

You say that the PEG assumption for Hydro One, if it increases its customers by one percent, its costs will drop by 0.514 percent, and this violates economy theory.

By costs, I presume you mean average cost, not total cost?

MR. FENRICK: By that I mean the total cost benchmark that comes out of the model would basically be reduced.

If Hydro One, if we go on Hydro One's data and add one percent customers, the PEG model would essentially estimate a benchmark that's lower than the current benchmark. So the total cost benchmark would drop by 0.5 or so.

DR. SCHWARTZ: Well, okay. I don't have that degree of knowledge of the model, but I think I see what you're saying.

But it wouldn't violate economic theory if a one percent increase in Hydro One's customers led to a drop in its average or per-customer costs? That would just indicate increasing returns?

MR. FENRICK: Exactly. Right. So that's not what we're saying here.

DR. SCHWARTZ: No.

MR. FENRICK: It's total costs. I get your question better now. It's total costs, it's not the unit costs.

DR. SCHWARTZ: So perhaps what your discussion in this chart really perhaps –- perhaps -- could be taken to say is that some of our distributors are still experiencing increasing returns, at least with respect to customers, and others are expecting decreasing returns -- I guess Wasaga would be one of them -- and that perhaps these are too small.

MR. FENRICK: I think we're drawing way too much out of the model. I think it shows that the model is just not able to accommodate the wide diversity in distributors. And remaining flexible on that returns of scale assumption is going to lead to -- I just cannot believe that as customers go up, total costs are actually going to drop. You know, there's economies of scale, but then there's impossibilities, and that, that's an impossibility.

So I think it shows that the data is just not able to accommodate...

DR. SCHWARTZ: Yes. Well, I agree with you, and if I understand what you're saying, that it is unusual to say that an increase in customers would cause total costs to drop, but it's not inconsistent with saying that average costs would drop?

MR. FENRICK: Right. Right.

DR. SCHWARTZ: Thank you very much.

MR. FENRICK: Yes.

MS. CONBOY: Thank you. Bill?

MR. HARPER: I think you were inviting both comments and questions.

MS. CONBOY: Yes, please.

MR. HARPER: So I have a combination of both.

The first couple go back to the EUCPI, which Mr.

Fenrick is recommending.

And it's been a while since I've looked at it, but I believe, actually, if you look at the definition of EUCPI as the way it kind of constructs it, it's constructed of both labour and materials and cost of capital.

I think there's supposed to be a recognition in there for cost of capital as well, so the issue may not be as great as what people were debating earlier.

The second thing is -- and this is the question –- is that we talk about the EUCPI itself being readily available. There was also the part of the recommendation that talked about using a weighted average, and I guess I was just curious whether it was immediately obvious what the weighting would be. Or is that something else that is subject to analysis and debate, as opposed to being sort of transparently obvious as to what that rating should be?

And maybe that's something you would comment briefly on. Or are we leading ourselves down a rabbit hole? I guess is what I'm wondering about.

MR. FENRICK: So in my presentation last time and in the report, it kind of laid out what I think the proper method would be as far as weighting that, looking at how much asset life would be expected, given kind of a 40-year straight line depreciation assumption.

Now, if you want to make that weighted average simpler, I don't think you're going to lose too much. If you want to look at last 10 years or 20 years, it's not going to materially change kind of overall index.

So, you know, yes, you could kind of argue over what that weight should be, but it's not really necessarily going to be a material discussion.

And so, you know, you can do it right, you know, exactly right, and what I would argue to be exactly right. Someone else might argue might be another way to do it exactly right, but the differences that you get are going to be small, and so it's not going to be a kind of a material discussion that really changes things.

So I don't think that would be kind of a rationale to completely discard, including capital-asset inflation, into the inflation measure, when, you know, capital costs are 50 percent of the distributor's business.

MR. HARPER: My final thing, just to comment, we seem to be focusing a lot on negative productivity. We have negative productivity and what that means in terms of productivity factor we should be using. I just comment, I'm involved in two other proceedings in British Columbia right now, actually, where similar analysis demonstrated negative productive for the gas industry, negative productivity for the electric industry, and in both cases the utility itself is coming in with a proposal of .5 as being the productivity factor that they are proposing. So that's our starting point. It may go up from there.

So, you know, I find it interesting that sort of, you know, it depends on the approach, to some extent, the utilities take in terms of the challenge that's before them, you know, in terms of how they look at it as a challenge or an opportunity, I guess.

MS. HARE: Just to make sure I understood what you said, the number coming out of the model was negative, but they said positive .5.

MR. HARPER: Yes, yes.

MS. HARE: Thank you.

MR. HARPER: And that's actually Fortis B.C., which is the electric utility and Fortis Energy Inc., which is the gas utility in B.C. at this time.

MS. CONBOY: Thank you. Dr. Cronin?

DR. CRONIN: Yes, I just wanted to make one final comment, and maybe make explicit what I think I was trying to say earlier maybe is the result of some of these threads of conversation. We've seen a 30-year secular decline in interest rates, and those started in the '80s, and we're now seeing the beginnings, possibly, of reversal of that.

That decline in interest rates from astronomic levels, in the high teens, for example, may have provided sort of unknowingly cushions, margins, around extended rate freezes. You know, some utilities have been on rate freezes for a very long time, and various IRs.

Well, if we are seeing a reversal of that secular decline -- and as a couple of us have mentioned, capital costs are about 50 percent of the total -- it's really incumbent that the IR going forward be as rationally effective as it can be, because the financing costs are really outside of the purview of anyone in the industry, the province. I mean, they're set by the market.

And so given that you have 50 percent of costs that may be seeing pressures that we haven't seen for a very long time, the rest of the IR needs to get the biggest bang for the buck it can.

MS. CONBOY: Thank you. That's helpful. Jay?

MR. SHEPHERD: Can I just respond to that? And maybe I'm misunderstanding what you're saying, Dr. Cronin, but it sounds like you're saying, For the last 30 years the utilities have benefited from lowering interest rates, and they've been able to have a cushion in their spending, and now that interest rates are going to go up we can't let that happen here. And that doesn't sound like it's fair to the ratepayers.

DR. CRONIN: I was making a statement about the factual context of interest rates. They've been under a 30-year decline, secular decline.

MR. SHEPHERD: And as a result there has been a cushion in --

DR. CRONIN: I said it may have provided a cushion, okay, and that may have been one of the difference between what happened 30 and 40 years ago when rates were lower and what's happened now. That's all. And I'm not --

MR. SHEPHERD: So it's going in the other direction, though.

DR. CRONIN: Rates are going to go up, okay? They're going to go up. They have already doubled in 18 months. They will probably double again. They may go more than double. So that's probably -- that's almost a foregone conclusion, once all the quantitative easing ends, and so that's a fact that you have to expect going forward, and that's out of the control of anybody in the industry.

MR. SHEPHERD: Right. Thanks.

MS. CONBOY: Dr. Kaufmann?

DR. KAUFMANN: I would just like to clear up two misunderstandings on this slide, the first on the PEG model. The first is the PEG model doesn't make any scale assumptions on any distributor. What we do is we estimate economies of scale. And you can take the estimates for different parameters in the model, and you can generate estimates that are specific to each company.

So I think that's important to point out. There are no assumptions anywhere in the PEG model about the scale economies. These are findings that come out of the data, the industry data.

The second thing to point out is that actually there are no examples on this slide of negative economies of scale, because the thing you have to keep in mind is that power distributors are multi-product firms. They provide a number of different outputs.

So if you want to look at the impact, the relationship, between changes in output and changes in cost, you can't focus on a single output. You would have to look at, for any given company, you would have to look at -- in our model we have three outputs that we use to construct the output index. We've got customers, we've got peak demand, we've got kilowatt hours.

So when you want to look at the relationship between changes in output and changes in cost, you have to look at all three of those outputs. You cannot look at one output in isolation. This doesn't tell you anything.

And in fact, what Steve has pointed out, this is not that uncommon. This happens quite a bit. You can get these sort of freak values, and if you focus just on that you can draw conclusions that somehow the model is not behaving appropriately, but what you have to do is you have to look at, if you just want to focus on the economies-of-scale issue, you have to look at the relationship of all three outputs and what that says for economies of scale, company by company, and when you do that you don't get these sort of crazy results.

So this really is not that uncommon if you focus on a single output, but if you would say, add the cost elasticity of Hydro One for customers, for volumes, or for peak demand, you get something much more sensible, and that's true across the Board.

MS. CONBOY: Thank you. Cameron?

MR. McKENZIE: Just maybe a point of clarification, maybe just even for myself, on slide 6, productivity factor. We show the productivity factor negative 33 -- .33, negative 1.28, but the trend is now positive, so are we saying that productivity will be increasing going forward?

MR. FENRICK: No, a positive trend variable essentially implies negative productivity growth, so it's saying costs -- costs are increasing by 2 percent above inflation, and the other factors in the model, which essentially implies productivity would be declining by 2 percent, then take away some of the scale economies and that stuff, but it essentially implies negative TFP. So you kind of have to put a negative in front of it.

MR. McKENZIE: Thank you.

MR. PROCTOR: Dave Proctor, from CHEC. I just want some clarification on a comment that Mr. Harper made earlier. I understand that the -- British Columbia has been experiencing negative productivity, and you mentioned that the -- maybe I'm wrong here, but the using a positive .5 productivity factor, is that the same as the X factor that we're using? That gives them an increase of .5 in their rates? Is that what you meant?

MR. HARPER: Gives them a decrease of .5 in the rates. And actually, unlike -- they're in a similar position to where we were last time. The productivity analysis they're using is based on U.S. industry data, because they only have two utilities doing TFP studies there. It's not as productive as doing both the utility ones like we have here.

MS. CONBOY: Thank you.

Are there any other questions before we break for lunch?

MR. FENRICK: Can I just make one more comment?

MS. CONBOY: Yes.

MR. FENRICK: Regarding Larry's comments on looking at economies of scale and not breaking up customers and those types of things, he is right that if you added everything up you don't get negative values, but it still shows, you know, a negative cost elasticity of customers, is in his words a freak value. It shows that the model is not able to accommodate all the variables it has in there, and it's coming up with uneconomic, impossible values. That logic holds.

If you do combine, you know, customers, volumes, and I think -- I believe peak demand are the three outputs, for instance, Hydro One, if you combine all those, he has an elasticity assumption of about .6, which means costs go -- or outputs go up by 1 percent, costs are only assumed to go up by .6 percent. That does not square anywhere close to a productivity factor of zero.

So I would say constant returns of scale assumption is still far more appropriate than even if you look at his model holistically and not break it into the pieces, which still should be aligned with economic theory. Even if you look at it holistically, like he's suggesting, I would still argue that a constant returns of scale is a far better and more -- a better assumption that aligns with the TFP findings and those types of things.

MS. CONBOY: Thank you. Lisa, have you got any questions over the internet?

MS. BRICKENDEN: No.

MS. CONBOY: Okay. Great.

We're going to break -- sorry, Jay, you have a question?

MR. SHEPHERD: Ms. Conboy, I'm the last presentation, right?

MS. CONBOY: You are.

MR. SHEPHERD: And I'm not likely to go longer than 30 minutes. If there is nothing else after that, I wonder if we should just get that done and have a late lunch, unless there is a problem with that.

MS. CONBOY: No, I think we're going to -- thank you for the offer, but I think we're going to break for lunch.

I would also like to say that if -- after we hear Jay's presentation and people have had some time to think about what we've heard this morning, don't feel compelled or don't feel that you can't ask questions again about what we heard this morning, after we wrap up with -- after Jay is finished.

So I hope that the experts are going to stay if there are further questions for them.

We'll see everybody back here at 2:00 o'clock. Thank you.

--- Luncheon recess taken at 12:49 p.m.

--- On resuming at 2:00 p.m.

MS. CONBOY: Looks like almost everybody has come back. And somebody new.

Welcome back, everybody. I thought I would make a quick announcement. I understand that Brian and Lisa have spoken to some of you about how people might reconvene to discuss some outstanding issues with respect to low-voltage and high-voltage costs and charges.

I understand we're not quite at a point yet to give a date and a scope of how that consultation might take place, but just to put you all -- give you all a heads-up that Lisa and Brian are still working with Hydro One, EDA, CHEC, and VECC to come up with a properly scoped session to deal with those issues, and you can be expecting a letter from the Board shortly making that announcement.

Before we get to you, Jay, I see we do have one person who has joined us, and for the benefit of the court reporter and those of us who are joining online, perhaps you could introduce yourself and where you're from?

MR. BACON: Bruce Bacon, from BLG.

MS. CONBOY: Thank you.

So unless anybody has any questions, we'll proceed with you, Jay.

PRESENTATION BY JAY SHEPHERD, SCHOOL ENERGY COALITION: INTERACTION OF INFLATION, TFP, STRETCH AND ICM

MR. SHEPHERD: I'm going to assume that Bruce came because he just couldn't miss hearing me.

MS. CONBOY: That's what he said.

MR. SHEPHERD: So as you correctly pointed out, Ms. Conboy, there were three experts and then Mr. Shepherd, and --

MS. CONBOY: You haven't gone through the proper qualifications here.

MR. SHEPHERD: Clearly. And School Energy Coalition really has one simple point to make, and this is why this is a relatively short presentation. And we raised this in our June submissions, but nobody else picked up on it, so we figured we'd better raise it in this stakeholder conference, because we think it's a very big issue.

What's happened in the last few years is that -- two things, really. First of all, now we're looking at productivity calculated based on past Ontario data rather than non-Ontario data and including capital spending, and we got a result of zero productivity. So that's -- obviously we have questions about that, and everybody else has questions about that, why is that, and Dr. Cronin in fact said we'd better find out.

And the second thing is that over the last few years, starting probably in 2010, the ICM, the incremental capital module, has been expanded and made more liberal, and this has been an evolution.

And there are different views as to where it is today, and I'm not going to try to debate that today. I think there are some people who believe that it's widely perceived, I think, today in the industry that any reasonable capital plan in excess of the threshold, which is somewhere around 130 percent of depreciation, will be -- will get extra funding, incremental funding.

And so certainly from the School Energy Coalition's point of view and perhaps some other ratepayer groups, the current state of affairs is that OM&A is on IRM, but capital spending is on cost of service.

So this all caused us to wonder, well, what impact would this more liberal ICM have in conjunction with fourth-generation IRM. And the point of this presentation is just simply to sensitize everybody to the issue.

I don't actually have answers. I have a problem that we feel is an important problem that has to be addressed. And we're hoping that people will deal with it in their submissions on September 25th and that, given the number of number-crunchers around the room, some people will actually go into more details on the data than we have been able to and come up with some interesting results.

So let's start with -- we just got the 2012 yearbook data that was just released, and here is what we see. For the whole industry, capital additions were 238 percent of depreciation, remembering that the threshold is somewhere around 130 for 2012.

We looked at -- we wanted to make sure that that isn't skewed by the bigger utilities, so we looked at it first as a simple average, and that's -- it's actually higher, which tends to mean that the smaller utilities spent a higher percentage than the larger utilities, but not by much.

And we also looked at that number, excluding Toronto Hydro and Hydro One, because we know that the total factor productivity was calculated excluding them, so we'd better do that too. And it's exactly the same, 238 percent.

So the result is that if you just looked at 2012 -- and I'm going to get to the other years in a second. But if you just looked at 2012, $854 million of capital additions qualified for ICM treatment. 854 million.

The -- if you convert that into a rate impact, it's somewhere around 2.6 percent. You can do a detailed calculation. We just took a fairly straightforward, simple calculation.

But the reality is that more than 60 LDCs in 2012 would have qualified for ICM treatment at 130 percent threshold. And the threshold was actually lower than that by a little bit, but it varied from one utility to the other depending on their growth rate.

So we're concerned about this implicitly additional rate increase that is available to anybody on IRM of 2.6 percent. So then we looked, okay, let's look at the previous years, and the previous years, in fact -- and I'm going to get to a table of the data in a second, but in the previous years the ratio was 192 percent of depreciation, as opposed to the 238 that we see in 2012.

And it was somewhat influenced by Hydro One and Toronto because, as you see, if you exclude them, the ratio is lower. But in every case, in every case, it's still much higher than the threshold.

And so if you then go with the table, you'll see, here's the data for all eight years that we have available to us, because we can only look at the yearbook data, and so that's the only place where we can get this data. I think the data for the prior years is available. But we weren't able to access it easily, so we just go through these eight years, which show a pretty clear trend.

And what those eight years say is -- and by the way, Dr. Cronin, this may be the answer to your question, why is total factor productivity declining in the last few years. Well, you just need to take a look at the big increases in capital spending to know why that is likely to be.

You'll notice the capital spending increased at a seven-year rate of 11.7 percent per year, compounded annually. Even if you exclude Toronto Hydro and Hydro One, who we know had big capital plans -- capital programs, it was still 9.4 percent for the entire rest of the industry.

You'll see some anomalies in 2011 and 2012, so for example, depreciation goes down in 2011 and 2012, and our guess is -- we could find it out, but we just haven't had the time to do it -- our guess is that that's because of IFRS. Depreciation went down. As people started to kick in IFRS their depreciation amounts went down.

We also see in 2012 a slight dip in capital spending, and that's probably also IFRS, because of the reduced ability to capitalize overheads.

But in any case, what we see is a huge increase over the last eight years in capital spending, no matter how you look at it, and what appears to be a new normal of capital spending somewhere between 225 and 250 percent of depreciation.

And if nobody gets any message out of my presentation today but this one, I want to make sure everybody gets this message. Those numbers are really scary for ratepayers. 10 percent a year or 11 percent or whatever a year in capital additions increases, and 225 or 250 percent of depreciation are very scary numbers for us.

All right. So what does that mean from a rate point of view? Well, let's assume that trend in capital spending increasing every year is going to level off, that the ratio with depreciation is going to stay roughly where it is now.

And there is no indication, as Mr. Fenrick said about something else, there is no indication that's going to happen, but let's assume that that happens.

The Board is proposing an inflation rate of about 1.7 percent. It's actually -- for 2012 it's 1.9 -- or 2014 it's 1.9 percent. But we actually average 1.6 and 1.9 and then dropped off the 5 -- it doesn't matter -- and a productivity of zero and an average stretch factor of 0.3. And by the way, I don't understand where Mr. Fenrick got .37, because my math -- and maybe -- I'm not a mathematician, but my math was 0.3 as the average stretch factor.

But in any case, roughly 1.4 percent is what the formula would give to everybody on fourth-generation IRM. Then we add an average of 2.6 percent for ICM, which almost everybody qualifies for.

And you'll see, by the way, if you go back to the previous slide, you'll see that in every single year, whether the industry includes Toronto Hydro or Hydro One or not, capital spending on average has been higher -- in most cases, significantly higher -- than the threshold.

So the result is that there is an average rate increase currently proposed by the Board in the Board's report, because of the ICM being included in this more liberal form, of four percent or more per year. And by the way, if four percent isn't enough you can apply for custom IR and get more than that, or in theory anyway.

So our view is this consultation is really about whether LDCs will get four percent rate increases for each of the next five years or more. That's what this consultation today is really about.

So this raises two issues.

The first, which is sort of the obvious one, is that four percent or more per year on average in the industry is not realistic. I don't think anybody in this room thinks that that could actually happen. Even though the formula, the current policy would suggest that, I don't think anybody believes that could actually happen.

The difference between what the empirical data says is a reasonable rate of increase in the next five years, of around 1.4 percent, and that four percent that includes the ICM is $1.44 billion over the next five years. That's a lot of money.

MS. HARE: Mr. Shepherd, do you mind if I interrupt you now?

MR. SHEPHERD: Yeah. Sure.

MS. HARE: The four percent, does that go back to your earlier slide, which assumes that everybody that qualified applied, but in fact that's not true?

MR. SHEPHERD: I'm going to come to that.

MS. HARE: Okay. Thank you. I'll let you finish, then.

MR. SHEPHERD: Okay. I can tell you one thing, though. We did a brief calculation on that, to see whether that would be a significant impact. And what we found was that if the only people who applied for ICM had capital spending in excess of the threshold of at least $5 million -- so then it's justified to make an application, right? If that's the case, 93 percent of the rate impact is still -- arises. It's an average across the industry of 2.4 percent instead of 2.6 percent. So that, I don't think that's a concern.

So the first issue, obviously, is the size of the rate increases that are implicit in the policy. In 2018 rates would be, if you assume the whole thing, $500 million higher per -- on an annual basis, $500 million higher in 2018 solely as a result of ICM impact.

And I don't think anybody in this room thinks their customers will accept that, because this is an important issue.

Then the other impact -- there is the obvious "this is too much" impact, but then the other impact is the implicit bias in this. The ICM, which would then be about 65 percent of the available rate increase, would be through making an application. If you make an application, you can get basically three times as much as if you don't make an application, because the ICM has such a big impact.

So then the question is who is going to make the applications. Clearly, the smaller utilities can't do this. So this builds in a bias against the smaller utilities, because they're not going to have this ICM available to them in most cases. It's only the larger utilities that have the resources to make ICM applications. They will get four percent or five percent or whatever. The smaller utilities will be stuck with the 1.4 percent. That's not a fair bias.

And by the way, one of the effects of that is that the value of the smaller utilities will drop, and in an area where we know that there is more OM&A activity going to come, probably, they will, as their values drop, they will be more likely to be acquired, but then when rates are harmonized by the acquirer, rates will go up, because -- not because there was spending in the local area of the acquired utility, but because there was capital spending in the acquirer that has caused the average rates to go up.

All right. So what are the solutions? Well, there's really two categories of solutions.

One is that you can treat this as part of the formula. You can say: If this capital spending is screwing up the formula, we can fix it by either increasing the productivity factor -- that is, we can accept that we can't allow this capital spending to continue, so we have to have a higher productivity factor to back out this unusual capital spending trend -- we could increase the stretch factor to accomplish the same result, or we could apply the IRM escalator only to the percentage of costs that is not affected by ICM. So basically accept the fact that capital is on a cost of service basis and shouldn't be escalated; the only amount that should be escalated should be the OM&A component, since that's the part that you can't apply for more money.

There's two problems with that.

One is that we then build in this sort of situation in which there is no incentive to reduce capital expenditures, because you can always ask for more. So why would you be forced to push down your capital expenditures? You're not. OM&A, you're forced to push down, but capital, no, you're not.

And then the second thing is it increases if you -- if the solution is within the formula, then it increases the bias against the smaller utility, because of course then the formula goes down. They're still only going to get the formula. Smaller utilities are still only going to get the formula, because they can't afford to make the ICM application. So then the disparity in rate increases between the larger utilities and the smaller utilities becomes higher.

So we don't think that building it into the formula is the right solution, but it is certainly a possible solution.

The other solution is to limit the ICM, because the real problem is that the ICM has developed into what appears to be now a cost of service for capital.

And the Board has now implemented or has now put forward an alternative for that, which is custom IR, which builds everything in, which says: Sure, we'll let you have cost of service for capital, but only as long as we get -- as we see the impacts on everything else altogether. We're not just going to look at capital in isolation.

So you could say: Okay. Let's fix that problem. And you can fix that problem two ways, either or both of two ways.

First, you can increase the threshold. So if your data, your past data, has an average threshold of or an average spend of, call it, 200 percent of depreciation, then you can say: Fine, that's the new threshold, plus or minus a growth adjustment. And it's only spending above the industry average that is eligible for ICM treatment. If you do that, you make it then consistent with your IRM formula. Or the -- and that would mean many fewer would qualify. Still quite a lot, in fact. I was surprised at how many would still qualify in 2012 if you did that, but their capital spending would have to be substantially above the norm or above the old threshold, if you like.

Secondly, the other possible solution is that you could go back to the original concept of ICM, which was spending out of the ordinary course of business, extraordinary spending.

So yes, if Oakville or Guelph has to build a transformer station, that has to be treated differently from capital spending, but everything else, all your normal capital spending, you should manage. So you can go back to that, and that would also solve the problem.

But right now we don't have any of these solutions in place, and therefore what we're putting out is sort of a menu of options, but more than that, our concern that the result of the interaction of the Board's report that was released last week and the existing ICM is very high and unpalatable rate increases across the industry.

MS. CONBOY: Thank you.

MR. SHEPHERD: I am available for questions.

Q&A SESSION

MS. HARE: I do have some questions. So I'm glad you mentioned Oakville and Guelph, and you could have, I think, thrown in Kingston in there, because I don't believe that any of those went to an oral hearing. I think they were settled. So I -- okay. Correct me.

MR. SHEPHERD: Sorry, Kingston was opposed. Kingston was actually the first of the new concept of ICM.

MS. HARE: My question then is, you say that then the ICM is only available to larger utilities. So how do you define larger utilities? You count Guelph and Oakville as a larger utility?

MR. SHEPHERD: Yes.

MS. HARE: Okay.

MR. SHEPHERD: They have the resources to do it, whereas Hearst does not.

MS. HARE: Okay. I have one other question -- and these are your words -- "10 percent increase, those are scary numbers".

MR. SHEPHERD: Yes.

MS. HARE: And I agree with you. 10 percent increase for ratepayers is a scary number. But are you not also scared with distributors not putting the money into ageing infrastructure where it's needed?

MR. SHEPHERD: Well, indeed, ratepayers are concerned about that, but you just need to look at the numbers. A billion-dollar increase in annual spending in the last eight years means they've already put a lot into ageing infrastructure. How much more do they need? That's the --

MS. HARE: Well, that's the question. How much more is needed?

MR. SHEPHERD: Well, and as Maurice has said, they're just starting. Well, if they're just starting, we can't afford it.

MR. TUCCI: Well --

MS. CONBOY: Okay. Well, let's --

MR. TUCCI: We can't afford the liability then.

MS. CONBOY: Dr. Cronin?

DR. CRONIN: This is a very interesting set of data. And in fact, Jay's earlier presentation, whenever that was, a year ago, actually, got me thinking along some of these lines myself. Now, this is a great example, because I think it's not as bad as it seems.

This data that we're looking at is a result in large part of the incentives that the utilities were facing, so incentive number one was, hold down, reduce, whatever, O&M. So they could do that in two ways. They could over-capitalize, and we know they did that to a dramatic fashion. So they went from 10 percent to 35 percent.

Secondly, they could actually add capital, and there is an elasticity of substitution, where they can shift from one input to another, so they can add more capital to legitimately reduce O&M.

Now, they may go more than they should have, you know, in an attempt to reduce it even further, so that's why I'm saying they are non-optimal capital input shares now.

But the bottom line is, if they hadn't been incented to increase capital so much, these numbers wouldn't be as large as they are. If those incentives are removed there will be a dampening effect on the capital-additions requirements.

MR. SHEPHERD: My concern is that in fact the opposite may be true, that a recent increasing liberalization of the ICM may mean that in effect the Board is saying to utilities, We'll give you more money for capital, but we're not going to give you more money for operating expenses. So where are they going to spend their money? They're going to spend it on capital.

DR. CRONIN: There is a real danger here that they've gotten into a non-optimal capital/labour ratio, and further progress in that direction or not progress will make costs even worse.

MS. CONBOY: But I'm hoping, going forward, some of that is mitigated by the discretion of what you capitalize, what you don't capitalize. I'm not sure how much, but --

DR. CRONIN: Taking the incentive away to focus on O&M will have a big impact. They will no longer have these non-economic motivations to make input choices. So if you go to total-cost benchmarking or total-cost IR, they won't have the incentives that they've had in the past.

MS. CONBOY: Sure. I guess there is the accounting component of it, and then there is the actual maintenance versus capital expenditure.

DR. CRONIN: Well, see, they can spend more money on capital legitimately, okay? They can take more money from O&M and put it into capital and reduce O&M requirements. So they had two ways of actually increasing their capital, both of which lowered the -- either actual O&M or the perceived O&M.

MS. CONBOY: Thank you.

MS. HARE: At the same time, the Board is asking for five-year asset management plans and capital spending plans. Won't these nicely fit together, in terms of making those optimal decisions?

DR. CRONIN: You know, in the long-run they should.

MS. HARE: Okay.

MR. SHEPHERD: The difficulty is that we've seen some of those capital plans, and they include very big capital spending increases in almost every case.

MS. CONBOY: Maurice, I think you wanted to say something?

MR. TUCCI: I'm just trying to get from Jay a sense of, when you say these are big capital increases, are you

saying that these are not legitimate capital increases?
MR. SHEPHERD: Schools also need capital. Hospitals need capital.
MR. TUCCI: I'm not asking schools. I'm saying to the distributors, do you say that they should not be spending this capital?
MR. SHEPHERD: That's not how it works. There's only so much money available from the public.
MS. CONBOY: Maurice, let him -- if you can ask him a question, let him finish.
MR. SHEPHERD: There is only so much money available from the public. The process is a process of prioritization, and the job of the Board, in my view and in my client's view, is to make sure that the amount spent on these things within the electricity sector in this case is not excessive relative to the rest of the economy.
MR. TUCCI: And that's my understanding of the five-year plan, is to make that balance and those tradeoffs and consult with customers about what is reasonable and what is acceptable to them, in terms of the tradeoffs. Do you -- do we improve the assets now, do we delay them, take the risk of having higher, you know, higher outages? You know, the idea is to talk to customers and get those tradeoffs and then incorporate that in a five-year plan.
MR. SHEPHERD: So -- and indeed, go to the customers and say, We want to charge you $500 million more in 2018, and you're going to get 18 minutes, less outages, less forced outages, each year as a result of that, and how many

do you think will say, Yeah, $500 million. Great. Let's do it? Zero.

MR. FENRICK: Well, certainly if you phrase it that way.

[Laughter]

But if you phrase it like, Hey, 500 million, and you share is going to be $40, or whatever the math comes out to, you know, that's -- if you phrase it correctly to where -- out of their pocketbook.

MR. SHEPHERD: You might pay $100. So $100 for 18 minutes. Will you do it? No.

MR. FENRICK: Well, I think there has been a number of surveys, and --

DR. CRONIN: Well, we've talked about that today, that the WTA in Ontario was profoundly -- in direction of, we don't want degradation in our service.

MS. CONBOY: Thank you. Other...?

MR. FENRICK: Another question: Are smart-meter expenses, capital additions, in here?

MR. SHEPHERD: Yes, they are. They're mostly in 2010, and I think some are in 2011, but I think they're mostly in 2010. And I think that actually explains the jump between 2009 and 2010, but I don't know. Other people can tell me better.

I mean, one of the things that I'm hoping to do by putting this data out is get the people in the room who are looking in detail at the data to parse those things out. I'm a lawyer, I'm not a mathematician.

MS. CONBOY: Thank you.

Maurice has posted a question and made a comment on these numbers that have been put forward by Jay. Are there any other distributors that would like to -- yes, thank you.

MS. NANNINGA: I'm just looking at the percentage numbers. There's the 238 percent of depreciation for 2012, and the 192, 2005 to 2011. I just noted the new changes -- with all the changes that were made for IFRS, that the percentage of capital additions really went up as a percentage of depreciation.

Our depreciation in Kitchener-Wilmot went 50 percent, basically, of what it was last year in 2011. So I just think that the jump that it shows here of 45 percent or whatever, it might be a bit inflated because of the changes due to IFRS.

MR. SHEPHERD: I think that's probably true, and -- but I think it's also true that the 2012 numbers are probably the new normal, because they probably have most of the utilities, or at least all of the big ones, on IFRS in those 2012 numbers. I think.

MS. CONBOY: Okay. Thank you, Margaret.

MS. SOUCIE: Michelle Soucie from Essex Powerlines. Was there any analysis done to show that 1 billion increase in capital costs? Is it 10 percent of all utilities are what's doing that, or is it 20 percent? Is any, you know -- so are we making changes to the IRM calculation that's going to affect everybody for 10 or 20 percent of the utilities that are causing an increase?

MR. SHEPHERD: Well, we didn't look at the increase from 2005 to 2012 on a per-utility basis, although we could. That would be a good idea. We did look at 2012 to see what how many utilities were spending at a substantially higher rate than depreciation. And as I said, 62 -- I think is the number -- would have qualified for ICM. That means they would be over 130 percent of depreciation in 2012.

MS. SOUCIE: So probably the ICM adjustment makes a lot more sense than the regular calculations. You're only hitting the ones who are actually affecting those numbers.

MR. SHEPHERD: Well, no, because that's not the ones who applied. That's the ones who qualified. In fact, only a few applied last year.

But we're already seeing the applications coming in for next year, and now with the sort of more liberal approach we expect more.

MS. CONBOY: Are there any other questions? Okay. Well, I think you've –– oh, sorry, go ahead.

MR. FENRICK: Jay, wouldn't you expect –– you kind of had a slide -- I forgot what number it was, but on the IRM, and you were kind of changing the productivity factor and the implications with ICM.

If you do increase the productivity or increase the stretch factor, I think you made a comment it does disproportionately hurt the smaller distributors.

MR. SHEPHERD: Yeah.

MR. FENRICK: And doesn't that also increase the incentive to apply to ICM?

MR. SHEPHERD: Sure.

MR. FENRICK: If you increase the productivity factor, you're going to have even more ICM applications as it kind of moves that?

MR. SHEPHERD: I was trying to be clear -- and inelegantly, probably -- that I don't think the first set of solutions are obviously the best, but you have to look at the whole menu of possible options before you can test what the direction is the Board should go in.

And so I was sort of putting them all out there so that when people in their submissions can look at the solution, maybe come up with some other solutions, and say: This one doesn't work, this one does, et cetera.

MS. CONBOY: Carm?

MR. ALTOMARE: This is probably a question for Larry.

Because one of my learnings was that Toronto Hydro and Hydro One Networks, they're using the US GAAP for their accounting, and the rest of the utilities -- as I'm understanding today and before -- they're on IFRS.

So does this create an inconsistency when you're looking at costs across the utilities, because the accounting is different for those two systems?

DR. KAUFMANN: The biggest thing we found was that it does create an inconsistency with respect to capital measurement in 2012. So that's the real implication of IFRS.

So we did have to go to a different capital measure for a number of companies that adopted IFRS. And it wasn't industry-wide, but I think we counted 15; 15 that we know for sure went to IFRS.

So that's the real implication in terms of IFRS for that type of accounting. I'm not aware of any implications in terms of comparability between the two companies that are still on GAAP and the ones that went to IFRS.

If it's only impacting capital too, then it would only impact the capital additions for one year. It would have a relatively minor effect.

MR. SHEPHERD: Carm, I can tell you that both Toronto Hydro and Hydro One have said that their capitalization policy and their depreciation rates would be the same under US GAAP and under IFRS, so I don't think it has an impact, that that difference has an impact.

The other differences that Larry is talking about do have an impact in 2012, a minor one, but choice of US GAAP does not, I don't believe.

MS. CONBOY: Bill, and then David.

MR. HARPER: Some of the conversation that's been around this has been, I know -- like, what about ongoing capital renewal projects, and people who need capital on an ongoing basis.

And it seems to me there is another tool in the toolbox, which is the custom IRM. I'm just offering a thought, that it seems to me that if the ICM is restricted for what is truly a one-off, and if somebody actually is going to renew their capital, they're hopefully not going to spend it all in one year; they have a plan, a five-year plan to do it. And they have five years' worth of capital spending that's in excess of the threshold. Hopefully -- that seems to be more amenable to a custom IR, because they want to look at capital spending over a number of years and get approval for it that way.

Maybe we're on the cusp right now of moving from the old system to the new system, and if we can be clear maybe in the new system as to what's ICM -- maybe we need -- Jay has used the word "extraordinary." Maybe "one-off" is more the word you should be using, for which there's a more ongoing need that's in excess of what you think you can measure.

That's the custom IR. That's just a thought I offer as a...

MS. CONBOY: Thank you. David?

MR. PROCTOR: David Proctor. I just want to make the point that the adoption of IFRS is not mandatory for regulated utilities until 2015. And I hear around the room talk about the adoption of IFRS.

In 2012, some utilities may have changed their depreciation amounts based on the Kinectrics study, but didn't in fact adopt IFRS, which would require a change in capitalization policies, for example, how much overhead you can capitalize and so on.

So I don't believe that impact of the adoption of IFRS is all there in 2012, as has been mentioned here so far. I think there is a much bigger impact coming for IFRS if there is no further deferral beyond 2015.

MR. SHEPHERD: Can I respond to that?

MS. CONBOY: Yes.

MR. SHEPHERD: The Board set out a policy that required that the two major changes that IFRS would require have to be implemented by everybody whether they go to IFRS or not. And those two major changes are the two that affect capital, overhead capitalization and depreciation rates.

And so I do believe that, with the exception of some that didn't implement until 2013, which were usually smaller ones, I do believe that most of the impact is in 2012.

MS. CONBOY: So maybe it's the terminology, in terms of you've made these two changes, and it goes to the issue of the standardization, if you will, of capitalization policy, versus the complete move over to, conversion over to IFRS.

MR. SHEPHERD: Yes.

MS. CONBOY: Still no questions on the Internet?

MS. BRICKENDEN: There is a question, Paula, but it might wait until -- it's a more general question.

MS. CONBOY: Okay. If there are no more questions of Jay, thank you very much.

Do you want me to bring up the -- what we talked about? Do you want to talk about the general question now, Lisa, or look at the comparison numbers?

MS. BRICKENDEN: Actually, I think Shelley's question is a good segue, so I'll read out Shelley Grice's question that she sent in.

She's interested in getting Larry's comments on two statements, one made by Adonis this morning, and one made by Steve.

Start with Adonis's, his comment that he is not optimistic that one could uncover sources and causes of negative productivity to determine the right explanatory variables. And if Larry couldn't find them, then they're not easily found.

Does Larry agree it would be difficult to do further analysis?

DR. KAUFMANN: Well, I do think a kind of forensic TFP examination would be difficult, but I think especially -- and I think this is a great, completely unintentional segue from the conversation we just had, which is, to me, if there was going to be an investigation of what happened at our IRM 3, it shouldn't just be limited to TFP.

It should be to look at the whole regulatory framework, the incentives that were created, the implications for customers, the ICM, how it operated, were there any unintentional incentives, the impact on reliability.

There have been a whole host of issues that have been mentioned here, and it would be possible to do an assessment of the IRM plan. I did more of those for the gas IRM plans, and that assessment was pretty favourable --

in fact, extremely favourable –- that it was good for customers, good for the companies, good for service quality, et cetera.

It seems to me the evidence for IRM 3 is much more mixed, and I think if there is any interest in really pursuing this, I would -- I would be in favour, I would recommend undertaking a similar sort of assessment for the IRM 3 plan, as opposed to just focusing specifically on TFP.

MS. BRICKENDEN: Shelley also asked, in response to Steve's comments, about the inclusion of insignificant business conditions in the PEG model versus PSE's approach. She was seeking some clarification on that.

DR. KAUFMANN: Yeah. I think it's important to recognize that because we -- our model does not make any restrictions and any assumptions on the extent of scale economies in the industry, to estimate scale economies you need to have certain other variables in the model to pick up that impact. And because of that, we have more variables in our model, to essentially pick up the impact of scale economies and the interaction of different variables with each other.

So in that sense it's a more general model, it's a richer model, but it's also a model that has to include more variables that are really just combinations of the variables, kind of what we think of as the basic output variables: customers, volumes, system peak, kilometres of line, and then percentage of customers added in the last 10 years.

So those were the five variables that were significant, but we have a number of those variables interacting with each other and are squared, and those are the sort of things you need to estimate scale economies.

So the reason we're not -- the reason it becomes more difficult to identify statistically significant impacts of other variables is because the model is already so rich, it already has a lot of different variables, and if you assume away the scale-economy issue, which is essentially what PSE does, then you do make it easier to introduce variables, new variables, in the model and make them significant.

But that doesn't mean they're really significant. It's -- that's really a reflection of the poverty, in a sense, of the specification and the fact that it's assumed so much of the -- what's really interesting about the cost structure away from the analysis.

So I don't know if that answers your question, but...

MS. CONBOY: Okay.

MR. PROCTOR: I have a general question. I don't know if this is the appropriate time, or is there another time would be better?

MS. CONBOY: Go ahead.

MR. PROCTOR: Okay.

MS. CONBOY: Have you got your mic on? They're very difficult to turn on, so you might as well go.

MR. PROCTOR: All right. Thank you.

And this is not a high-level economic question. This is a practical calculation question, which typically is the thing I get involved with. So my question is, I've tried to -- and maybe it's my -- not my ability to do the correct calculations, but I have tried to take the PEG equation and come up with the predicted value and compare that to the actual value to basically come up with the ratios that are used for purposes of calculating the stretch factor groups.

I have not been able to break the code, to be blunt. So I was wondering, is there an example that someone has put together to show how the PEG equation actually does the prediction? And is that something I'm missing, I haven't seen it anywhere, or...

DR. KAUFMANN: It's not anything you're missing. We don't have any explicit tables or steps that we go through to do the calculation, but unfortunately this is a very technical issue, but what we do is, you can't -- you will get close to the prediction if you use the co -- just the coefficients from the model and you substitute your own business conditions in there. You'll get close, but you won't get there exactly, because we do -- we use all the information in the model, and we use essentially an out-of-sample prediction. We don't use the company's own values to generate the model parameters that we use to predict the company, so that we can have an external projection for that company. And also, it makes it easier to estimate the standard errors.

Very technical issues. I don't want to get into it. But that's the way we do it. So the model parameters we actually use for each company's prediction are going to be a little bit different than the industry-wide model parameters that we report in the tables.

MS. CONBOY: Indeed.

MR. PROCTOR: It does make it a little difficult to try and predict where you're going to be, which sometimes is helpful when you're trying to manage those costs. So it's just a -- I know it's a detail, and I apologize for that, but it's something that -- it doesn't allow the LDC to basically predict their costs, and that's a difficult thing.

DR. KAUFMANN: And I can sympathize with that statement and that issue, but as I said, it will get -- I think it will get you fairly close. It just will not give you a, you know, a dead set on 100 percent prediction.

MR. PROCTOR: Okay. Thank you.

MS. CONBOY: Thank you.

I'm sorry, I remember Toronto Hydro, but I do forget your name.

MR. BALASHOV: Well, it's my first time speaking here. Dimitry Balashov. And I want to go back to something before lunch, so apologies for that. Something Bill Harper had mentioned about the B.C. utility, about Fortis undertaking essentially to take a positive productivity factor in lieu of the fact that the actual analysis shows that TFB is around zero.

So I just kind of wanted to ask a bit of a clarifying question, I guess, or potentially put it into context.

It's my understanding from looking at that application that, first of all, there is no stretch factor involved, and second of all, I believe that Fortis is actually asking for a number of costs to be treated as pass-throughs, so things that in Ontario would be included within the I minus X formula, I believe things like pension costs, insurance costs, as well as costs of capital, I believe. I think they're actually asking for that to be kind of flowed through at the natural rates of increase, if I'm not mistaken, and I would like to get Bill's take on that, but I guess essentially what I'm trying to make is that under those conditions I guess it would be a little bit more bearable or it would change one's perception as to what is and what isn't an appropriate productivity factor they can live with.

MS. CONBOY: Thank you. Bill, do you want to...

MR. HARPER: No, he is correct in a sense. I mean, everybody has got a sense of what's handled through deferral accounts versus what's handled through the revenue requirement, and there are certain costs that they're looking to pass through. These are unknown costs like future pension costs. They've also got, I'd put it something akin to a permutation or combination on the ICM, in terms of very large capital would be outside the plan, which I view as being somewhat akin to the ICM module we have here, where very large caps outside the plant, so, you know, no two plants are precisely the same, in terms of the -- and exactly how specific costs are being treated on a conceptual basis.

And you're right, there is no stretch factor, like, you know, so that you could use their .5 as being equivalent to the zero plus the stretch factors we'll be dealing with here sort of thing. No, you're right.

MR. BALASHOV: No, the point I was trying to make is that it just seems that there was a much larger portion of the cost that here would be viewed within a distributor's control and thus expected to be offset elsewhere, that they are being passed through, so perhaps...

MS. CONBOY: So be cautious when you're making comparisons in two different jurisdictions --

MR. BALASHOV: Indeed. Absolutely. Thank you.

MS. CONBOY: Okay. Thank you.

We have no more questions at the end?

MR. FERGUSON: Dave Ferguson, with Entegrus Powerlines. This is a general question for Dr. Kaufmann. It has been suggested by Mr. Fenrick that the cohort should be divided into quintiles, as opposed to scoring break points. I note that in one of the Excel files on the Board's website a scenario was also run with a more symmetrical, quintile-like approach. Could you provide insights on why the score-range approach was selected instead of the quintile approach?

DR. KAUFMANN: I believe that's a Board issue. That's not a question for me.

MS. CONBOY: Thank you.

MR. FERGUSON: Is there someone who could answer that question?

MS. HARE: I actually think the report speaks for itself. We looked at different models and decided that the best comparison was not to compare utility to another utility, because we heard a lot about that, but to compare to what the projected costs should be. So utility then is competing against itself, and that's the approach that we're suggesting.

MR. FERGUSON: Thank you.

MS. HARE: Subject to comments, though. I think that was made very clear in the report that this is somewhat unusual, that it is a Board report, but it is a draft, because we would like to hear further comments.

MS. CONBOY: David?

MR. PROCTOR: I just want to follow up on Larry's response to Bruce earlier about the prediction model there. Larry, you talk about it being an out-of-sample prediction process, and I was hoping today that I would go home with the -- some kind of calculation where I could show the utilities how to predict these costs, and when you responded to us I didn't quite get that. You said you could come close, but I didn't understand what I would have to do to get close.

DR. KAUFMANN: Maybe what we could do is we could -- this is a diff -- well, when you're talking math it's difficult to verbalize it. Maybe what we could do is we could develop an algorithm, something like that, that would be helpful to the industry so that they could input their data and generate a prediction, and that they could get a sense of where they are, and, you know -- so they have a sense of where the benchmark is and what they're managing towards.

So we can -- I don't think that would take a lot of work, but, you know, I would be happy to try to do that if it's important enough to the industry to understand that.

MR. PROCTOR: I think that would be helpful.

MS. CONBOY: Thank you. And then Bruce can give his business card too.

Jay?

MR. SHEPHERD: Can I go back to what Bill and -- Dimitry, is it -- were talking about. So surely you can't compare apples to oranges, and the Fortis situation is not the same as here. But we have an example closer to home -- that is, Union Gas -- that has already agreed to the next five years with an X factor of 60 percent of inflation, so give or take 1.1, 1.2 percent, a combination of stretch and productivity, in the face of looking at their productivity and the productivity of the gas industry, which Enbridge has filed evidence at zero.

So this suggests that I'll get a much more comparable situation, much, much more comparable. A substantial productivity factor is still reasonable, because a big utility has agreed to it.

MS. CONBOY: Thank you. Well, it –- Jane?

MS. SCOTT: I'm not sure if it's on the website, but were we going to get to see the adjustments that were made to the 2012 data, in terms of the IFRS and the smart meters?

DR. KAUFMANN: The smart meter adjust -– is this on?

MS. CONBOY: It is on. It's off.

[Laughter]

DR. KAUFMANN: The smart meter adjustment is in the data set, so that's already there. You can trace that through. So that's there.

The adjustments to the data, there were a very small number, and I don't know that we have itemized those anywhere on -- within the data set that we provided. We can probably do that. That might be a better thing to do, just to submit it to the Board and they can put that on, put that on the site.

MS. CONBOY: Okay. There's one more thing we wanted to put up on the screens, and I will hand it over to Lisa and Larry.

There's been a significant amount of talk between the -- three of the experts in terms of what their efficiency rankings yield, and a comparison of whether distributors are very different in terms of where they're ranked.

And I believe it was Larry who ran the numbers, and has some results to put up and have a bit of discussion about.

DR. KAUFMANN: Yes, thank you.

Everybody should be getting a copy of this, but it's on the screen and hopefully it's not too difficult to read.

But what this is is it just brings together the three models, the PEG model, the PSE model, and Prof. Yatchew's model for EDA.

It shows, company by company, where the company is ranked on each of these three models. And the ranks start from 1 to 73, and these are only the econometric models.

So a rank of number 1 would mean that the difference between your actual costs and your predicted costs was the lowest in the industry. And then obviously the converse would be true for 73.

So what we have here are the rankings. Just the rankings, not that actual predicted value, but the rankings for PEG, the rankings for PSE, the rankings for EDA.

And then at the bottom of the second page just performed some simple correlation coefficients. A correlation coefficient is a number between zero and one, which kind of shows how closely two series are interrelated.

And as you get closer to one -- one would be perfect correlation, perfect interrelation -- as you get closer to that, then you get a number that shows that the two series are more highly correlated.

And what you can see is that the PEG and EDA numbers, there's about a 90 percent correlation. So in other words, there's a very strong -- even though the models are different, and it's true that there are challenges about benchmarking and identifying performers, about 90 percent of the time the PEG and EDA more or less agree on the rankings and who is –– and where they rank, where the companies rank.

You can just kind of start here at the top and just see, if you take a few examples -- and I'm not trying to pick on anyone or praise anyone. This is just -- these are the numbers that are out there on the different models.

Algoma Power, PEG had got them at 72; PSE has them at 73; EDA has them at 73.

Atikokan, PEG at 52; PSE 55; EDA 54. Very similar. There are a few differences.

But I just thought it would be instructive. Given the talk and all the potential uncertainty that's been created around benchmarking -- and we shouldn't underestimate the challenges around doing benchmarking correctly or appropriately, but I just thought it would be instructive for people to actually see how these models compared, and see that there is, in fact, a pretty high degree of coincidence in terms of the rankings that come out of the models.

There are some differences, and you can go through here and identify the differences, you know, on your own, but I think a few patterns will be evident, but...

That's all I wanted to say. I wanted to make this information available to everyone before we left tonight.

MS. CONBOY: Thank you.

Are there any questions on...

MR. SHEPHERD: I was going to ask whoever from CLD wants to answer -- maybe Mr. Fenrick or maybe some of the members -- why is it that the PSE ranking in every single case ranks the CLD members better than either of the other rankings. And what is it in the model that does that?

MR. FENRICK: I think with PEG's new rankings, with the 2012 -- I think these are 2011 results, right, Larry?

Right. So if you look at Larry's new results, you probably --

MS. CONBOY: Sorry, could you repeat your answer, Larry, for the court reporter?

DR. KAUFMANN: Yeah. These are results through 2011, because with the 2012 data you won't be able to compare, because they will be using different data that PSE and EDA used.

MR. FENRICK: Right, so for a fair comparison to 2011, you can look in 2011, but if you look at 2012 PEG's rankings, you know, for instance, I know Horizon goes from 22 to number 8, I believe, in PEG's model. So the question might be: What changed there also?

And probably the same explanation of why PEG's ranking from 2011 to 2012 changed, it's likely due to the scale economies, that PEG's model changed the assumptions -- or not the assumptions, the results. Given their flexible form, it changed from 2011 to 2012, and so that was the movement.

MR. SHEPHERD: All three of these columns are 2011, right?

MR. FENRICK: Right.

MR. SHEPHERD: So have you done 2012?

MR. FENRICK: No.

MR. SHEPHERD: So then this is an apples-to-apples comparison. And if you did 2012, then we could compare yours to Larry's, but you haven't?

MR. FENRICK: Correct. Yeah, then we could compare it.

I would also add to that answer I think this is very informative. It shows the power of econometric benchmarking. Even -- yes, there's differences between models, but in general they are agreeing a good deal of the time.

I would say a ranking, you know, one of the explanations can be we're adjusting for more things in our rankings, so the fact that ours are a little different from PEG's or EDA's, that's to be expected, given that we're correcting and adjusting for Board variables.

MR. SHEPHERD: I'm just wondering whether you -- you had a thing about economies of scale, where you said that economies of scale would not be treated as a business condition or would be treated as -- different than Larry, anyway.

Is that the reason why you have this difference? How you treat economies of scale?

MR. FENRICK: There's a couple differences.

Number one, we're making assumption on returns of scale, whereas Larry's model keeps that flexible and lets the data determine the economies of scale. So we're making an assumption there.

We're also adding more business conditions into the model, so that's another difference going on. I believe there's five more business conditions, four or five, somewhere around there, that our model is adjusting for that PEG or EDA is not.

So there's -- along with the 2012 difference, as well. So there's, you know, a number of differences going on. I can't really pinpoint --

MR. SHEPHERD: That helps me.

MR. FENRICK: -- why, but...

MS. CONBOY: Thank you very much.

DR. KAUFMANN: I just wanted to add I know Adonis ran the numbers again with 2012. And I just took a quick look at them the other day, but he didn't want to present them yet because he wanted to follow up with Larry about trying to figure out what's causing these differences, because he is trying to do the same analysis as you are but he finds -- you know, he's finding again there's little anomalies. Like you said, it's like 90 percent are there but there's these other 10 percent that are off for some reason, and he doesn't know why and he is trying to figure that out.

So it still raises questions about what's going on, what is it -- like he wants to know why it is that there's these -- 10 percent of the utilities are moving around to different places.

MS. CONBOY: Thank you. David?

MR. PROCTOR: I just have one last observation to make. You mentioned this morning that you don't want to hear anyone out in the hall at the end of the day, saying:

Jeez, I wish I brought something up.

Anyway, there is an issue with the smart meter information. I know the OM&A and depreciation expense have been captured in Account 1556. It was supposed to be captured in Account 1556 for the LDCs. And some of the regulatory accounting instructions, I won't say they're not clear but they're not handled the same way in all utilities.

So maybe a lot of the OM&A costs maybe didn't get into Account 1556, and that may present some issues for some utilities where smart meter costs are included in the benchmarking.

But there was a RRR report required by the Board, and I think it's after the smart meters are taken into rate base they have to prepare a RRR reporting of all their OM&A costs and capital, and I just wondered maybe if the Board could consider comparing that RRR reporting to the, what they use in account 1556. There may be some changes there. I'm not sure how significant they might be, but if it could be.

MS. CONBOY: Thank you. Okay. Go ahead.

MR. FENRICK: also, to follow up to Jay's comment about the CLD members doing better in our model, kind of, you know, maybe to insinuate there was some sort of bias there, I would say that the CLD members in PEG rankings did quite poorly in the initial rankings. If you took the average, it was well over in positive territory. I forget what the number is. 10 to 20 percent over costs was the average benchmark.

And so I would just say initially that that doesn't pass the smell test, as far as being right. So it kind of came from a point where the CLD distributors were kind of being biased against -- and in our model I think -- I feel it corrects that. If you look, there's a good mix. It's not like the CLD members are all in the top 10 or all in the top 20. I think we just kind of corrected something that was going on there that might have been flawed.

MR. SHEPHERD: Yes, I'm not sure that's actually correct. I do believe the correct answer is that in the PEG rankings Hydro One Networks and Toronto Hydro are last and second-last, but everybody else in the CLD is -- I guess Hydro Ottawa is around the middle, and then the other three are in the upper categories. So I don't think it's correct to say that there is a bias downwards of CLD.

MS. CONBOY: Thank you. Well, unless -- there are no further questions. We would like to thank you very much for your time, your presentations, your thoughtful questions. You've certainly given us a lot to think about, and we look forward to your submissions on the 25th of September.

--- Whereupon proceedings adjourned at 3:11 p.m.