

# ONTARIO

## ENERGY

BOARD

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| **FILE NO.:** | EB‑2010-0379 |  |
| **VOLUME:**  **DATE:** | **Encouraging Electricity Distributor Efficiency**  **Stakeholder Conference: "Empirical Work in Support of Incentive Rate Setting in Ontario"**  **1**  **May 27, 2013** |  |

**EB-2010-0379**

#### THE ONTARIO ENERGY BOARD

**ENCOURAGING ELECTRICITY DISTRIBUTOR EFFICIENCY**

**STAKEHOLDER CONFERENCE:**

**"EMPIRICAL WORK IN SUPPORT**

**OF INCENTIVE RATE SETTING**

**IN ONTARIO"**

Held at 2300 Yonge Street,

25th Floor, Toronto, Ontario,

on Monday, May 27th, 2013,

commencing at 9:36 a.m.

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VOLUME 1

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ROSEMARIE LECLAIR Board Chair

CYNTHIA CHAPLIN Board Member and Vice-Chair

MARIKA HARE Board Member

PAULA CONBOY Board Member

KEN QUESNELLE Board Member

LISA BRICKENDEN Board Staff

DUNCAN SKINNER

AJIRO WINTHORPE

BRIAN HEWSON

LAURIE KLEIN

PETER FRASER

PRESENTERS:

ADONIS YATCHEW Electricity Distributors' Association (EDA)

STEVE FENRICK Coalition of Large Distributors (CLD)

DR. LAWRENCE KAUFMANN Pacific Economics Group

ALSO PRESENT:

GRANT BROOKER Cambridge and North Dumfries Hydro

MORRIS TUCCI Electricity Distributors' Association (EDA)

DWAYNE QUINN Federation of Rental-housing Providers of Ontario (FRPO)

CARM ALTOMARE Hydro One Distribution

PHIL MARLEY Midland Power Utility Corporation

JUDY KWIK Power Workers' Union/Elenchus Research Associates

JAY SHEPHERD School Energy Coalition (SEC)

BILL HARPER Vulnerable Energy Consumers' Coalition (VECC)

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NO EXHIBITS WERE FILED IN THIS PROCEEDING

NO UNDERTAKINGS WERE FILED IN THIS PROCEEDING

Monday, May 27, 2013

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

Opening Remarks by Ms. Conboy, Ontario Energy Board

MS. CONBOY: Good morning, everyone. Thank you for participating in today's stakeholder conference to discuss the report prepared by Board Staff's expert consultant, Dr. Lawrence Kaufmann and his team at the Pacific Economics Research Group entitled "Empirical Work in Support of Incentive Rate Setting in Ontario", affectionately known as the PEG report.

My name is Paula Conboy, and I am a Board member at the Ontario Energy Board. With me today is Marika Hare, Cynthia Chaplin, Rosemarie Leclair, our chair, Ken Quesnelle, and I don't see any of the other Board members here yet.

With us today on Staff, beside me is Lisa Brickenden, in front of me Duncan Skinner, Ajiro Winthorpe, Brian Hewson, Laurie Klein. I see Peter Fraser at the back, and we will have other Board members joining us over the next two days coming in and out of the conference as their schedules permit.

This is a stakeholder conference, meaning that it's not a hearing, but a consultation convened by our Chair to support consideration by Board members of policy proposals that are formally before us.

This proceeding is to provide you with the opportunity to make oral representations to the Board and allow us to obtain information and views to inform our consideration of the proposed policies.

Marika and I are the Board member advisors to this policy initiative, which means, in part, that we will be here throughout the next two days, but it also means that we will be reporting back to the full Board on what transpires over the two days. And, as I mentioned, you will see some of the other Board members coming in and out as their schedules permit.

So what are we hoping to gain from the next two days? We would like to get an understanding, through your presentations and discussions, of your views on the PEG report. The PEG report makes specific recommendations for the inflation, productivity and stretch factor parameters for the Board's incentive rate setting. The PEG report also makes specific recommendations for the benchmarking of electricity distributors' total costs.

We would like to get an understanding of your views on the report, as well as any alternatives or other options participants may have.

As you know, the Board provided its policy direction for matters with respect to the inflation productivity benchmarking in the RRFE report. We are not going to be revisiting those over the next two days.

Furthermore, we are not revisiting the three rate-setting methods and other policies set out in the report. Lisa and I can outline those, if you would like, or just commit to interrupt people and remind participants if we do venture into issues which the Board has already rendered determinations on.

We had initially put forward an agenda that you will have noticed has been posted on the website. We would like to make some changes, some schedule changes, to that agenda and here is why. We understand there are two other experts that will be presenting over the next two days.

The Coalition of Large Distributors has retained Steve Fenrick, and the EDA, I believe, has retained Dr. Yatchew. We only received the slide deck of Mr. Fenrick and the CLD late on Friday and the slide deck of Dr. Yatchew this morning, and that puts us in a bit of an awkward position in terms of getting a good understanding of what their comments on the PEG report, on the PEG analysis, as well as any alternatives that they may be putting forward.

So here is what we are going to do. We are going to start the presentations today with Dr. Yatchew going through his slide deck. We will ask participants -- we will get participants to ask any questions of clarification of Dr. Yatchew's work, similar, I believe, to what we did on May 16th for the PEG report.

We won't get into debate over the merits, looking at alternatives to what Dr. Yatchew has proposed. That, we need some time to appropriately consider what he is putting forward. But certainly questions of clarification are welcome after Dr. Yatchew is finished.

We will then move to Mr. Fenrick, who will give his presentation. Mr. Fenrick, we are wondering whether there is a report following the slide deck that we have? Perhaps you could address that when you make your presentation.

We will open up the floor to questions, again, of clarification of Mr. Fenrick's presentation. Following that, we will have Dr. Kaufmann come up and make a presentation of his work. At that point, we will venture in a little further, shall we say, than questions of clarification, because parties have had the opportunity to review Dr. Kaufmann's work in greater detail, and then we will adjourn for the day and we will reconvene tomorrow, where we will have the three experts sitting up here.

We will ask questions, perhaps that go beyond questions of clarification, of the three experts, and we will see where we are at at that point by the end of day tomorrow when we are done with questioning the three experts. So, for example, there will be a question to one of the experts. The other two will have a chance to answer, as well, similar to what we have done in other type of experts' conferences.

And, as I said, then we will see where we are. Are there any questions on what I have said so far?

MR. SHEPHERD: Yes. First of all, do we know when we will get Mr. Fenrick's report, and does Mr. Yatchew -- Dr. Yatchew also have a report, because it's going to take some time to look at this?

MS. CONBOY: I understand what you are saying, and I did ask Mr. Fenrick -- when he comes up to make his presentation, both of them will be in a position to say whether there is a full report that is attached to the work they have done.

MR. SHEPHERD: Will we have a chance to ask questions on those reports at some point before we make our submissions in writing?

MS. CONBOY: That is what we are going to revisit tomorrow, Mr. Shepherd. We will have questions of them tomorrow. It will give you some time to internalize what it is they have presented to you today, and then we will see where we are at. But we do want to give adequate time to consider the other two experts.

So if there are no other questions, I am going to hand it over to Lisa Brickenden, who has become the expert in moderating these sessions, and I will leave you to it, Lisa.

MS. BRICKENDEN: Thank you, Paula.

I just have a few minor logistics matters I would like to cover off with you before Mr. Fenrick comes up and does his presentation.

As you know, we are being transcribed, and our transcriber, Lisa, my namesake, is to my left. Please identify yourself when you have a question for her. And our session today is also being broadcast via the web. The people who are listening in remotely are invited to send in their questions to e-mail. Laurie Klein here is monitoring the RRF account and will read out your questions as they come in.

Additional microphones are available, so later on when we do have Q&A, please don't hesitate to ask them. Perhaps my colleagues with can walk around with them at that point to make it easier to for you to ask your questions.

With respect to how the presentations are set out, as Paula has indicated, we have asked our experts to present for 30 minutes, and then open up for clarifying questions of an hour or so. I will keep track of the time, to the best of my ability, without unduly interrupting the process and keep things on schedule.

Any of you who would like to make a brief presentation tomorrow after we have had the opportunity to have the expert panel discussion, please let me know at any point throughout the day. We have set aside some time tomorrow afternoon for that.

Finally, I want to speak briefly to the evacuation procedure. I see some new faces in the room. In the case of an emergency, if you hear an alarm, there will be a general alarm in the building. I will suspend this meeting and provide you with the necessary instructions to follow in order to achieve an orderly evacuation if necessary, okay?

Aside from that, if there aren't any questions with respect to logistical matters, I would like to invite Mr. Fenrick up -- oh, I am sorry, Adonis.

EDA Presentation by Dr. Yatchew:

DR. YATCHEW: Thank you so much for inviting us back. My name is Adonis Yatchew. I teach at the University of Toronto, and I have been involved in Ontario's electricity industry for more than 30 years. I see quite a number of faces here that I recognize back from the last time we had a proceeding of this type in 2008, and my presentation will be relatively straightforward, I think.

However, I should point out that underlying the actual qualitative descriptions that will be provided this morning, we have actually written software that -- written code that does a similar type of data analysis to that that was done by Dr. Kaufmann and his team at the PEG group.

So let me begin with the numbers. The updated numbers are an inflation factor of 0.5 percent, a productivity factor that is just a little bit above zero, at 0.1 percent, and proposed stretch factors ranging from zero to .6 percent, divided into five efficiency cohorts. Some of these numbers have been updated from the original report that PEG provided on May 3rd and that we have had the opportunity to look at more recently.

Applying these components to the incentive regulation formula, we get an allowable rate increase that is the usual rate of price inflation minus a productivity factor, minus a stretch factor, and this results in a range of rate increases from minus 0.2 percent to plus 0.4 percent. For example, the median utility would receive a rate increase of 0.1 percent, basically a rate freeze.

Let me comment a little bit about the changes that have been put in place from the previous proceeding in 2008 to those that are in place now. The first one has to do with the kinds of data that are being used to calibrate the incentive regulation mechanism.

We are now relying on Ontario data, rather than on US data. This has involved a massive data development effort on the part of the OEB, its advisors, various stakeholders, and of course utilities, and I think that this has been an excellent step in trying to disentangle an industry that is not only complex in the kinds of variations that we observe in it, but also complicated by the dynamic nature of the industry at this point in history.

And with that, to the second point - under 1 there on the slide - even more, this reliance on Ontario data is even more critical now as Ontario policies diverge from US policies. So in 2008, we argued that there is sufficient similarity between the US electricity environment, electricity industry environment in Ontario, that we could plausibly transfer their parameters into our setting under the circumstances, since we didn't have sufficient data on capital in this province. That possibility for transfer weakens considerably now that Ontario has taken on a very different path from much of the United States.

The second important difference is that we have now turned to total cost benchmarking rather than benchmarking simply variable or OM&A costs, a very important step for reasons that we set out in 2008, that many parties set out in 2008, and I am very happy that the Board did expend the resources in moving in this direction to try to assemble this data set.

There is a slightly more subtle point for the technically oriented. The models that are being estimated now, the cost models that are being estimated, not only include costs, but also have a component that deals with factor shares, so the shares of the various factors of production.

This turns out to be -- again, it's a technical point, but it turns out to be a very important one if one wants to get more accurate, more reliable estimates of the parameters of this industry.

And a third very important difference has to deal with the industry-specific price index that the Board, or at least the Board consultant, has now developed in proposing for the industry.

I would like to spend some time on the productivity factor. The PEG report proposes two methodologies. One is based on total factor productivity, an index-type model. The second involves estimation of costs using an econometric model. And PEG has done considerable and detailed empirical analysis using each of these two techniques.

The index-based calculation of total factor productivity obtained by PEG for the period 2002 to 2011 for Ontario, if one includes all the utilities for which we have reasonable data, the productivity factor is minus 1.24 percent per year, which would appear to suggest that the industry is somehow becoming less productive, which I am going to argue is not the case a little bit later.

If you exclude Toronto Hydro and Hydro One, the initial estimate in the May 3rd report was that productivity growth was close to zero, minus 0.5 percent. We received updated numbers on Friday, an estimated productivity factor of 0.1 percent.

I understand that there is a corresponding number, which includes Toronto Hydro and Hydro One; in other words, all utilities. But that can be made available - as I understand it, it is not yet available - using the updated data.

And PEG proposes to exclude Toronto Hydro and Hydro One from the TFP index-model calculations, essentially because of the large impact on calculated TFP.

Let me turn now to the second tool available here for trying to disentangle the productivity and cost pressures in this industry. And that's -- that consists of these cost models that are estimated using fairly standard econometric and statistical techniques.

Using these Ontario data for the same period, PEG estimates a distributor cost model which captures the effect of a range of factors. First of all, prices of inputs, capital and labour. This is an industry which produces various outputs. It's a multi-product industry, three of which we know we can measure: number of customers, capacity and energy, various business conditions, such as -- that differentiate utilities from each other, the percent of lines that are underground, the service area, the line length, which in turn implies a density when you combine that with the number of customers, and recent rates of growth of the industry -- recent rates of growth by each distributor -- within each distributor.

And, lastly, there is a variable that is intended to capture cost trends in the industry. It is referred to as the trend variable in tables in the PEG report. That's the coefficient I would like to focus on.

The estimated trend coefficient indicates that after controlling for numerous factors, there has been upward pressure on costs in this province in excess of 1 percent per year over this period.

So how does one interpret this kind of empirical result? And, by the way, the estimate, there is some variation in the estimate. The fine print on this slide points out that the estimated trend coefficient is about 1.4 percent. If you include all utilities, it drops slightly to 1.1 percent. If you exclude Toronto Hydro and Hydro One, we have now received a revised data set on Friday, and the numbers there suggested that the trend coefficient is about 1.2 percent.

So there is some variation, but not a lot, and that coefficient is estimated reasonably precisely. It's statistically significant and it's material.

Normally one would expect a negative trend coefficient due to improvements in technology and more efficient use of resources. And one interpretation is that this reversal is due to slowing growth in sales driven by economic conditions particularly since 2008, subsequent to the last proceeding, and conservation programs and so forth.

There have been dramatic changes in the Ontario electricity industry, and these have led to significant cost increases, additional responsibilities undertaken by distributors, as a result of the, for example, Green Energy Act, FIT programs, smart meters and other initiatives have also contributed to cost increases, and these cost increases do not have a corresponding measured output that would appear in the cost model.

This finding that is an upward trend in costs is broadly consistent with cost pressures in other jurisdictions which have implemented aggressive agendas for promoting conservation and renewables; for example, FIT programs.

So which approach is more appropriate, TFP modelling, index modelling or cost function modelling? I would submit that there are strong arguments in support of the use of cost models over index models.

First, cost models rely on detailed utility-specific data, much of which is not incorporated in TFP index models.

Second, cost models do not give disproportionate weight to large utilities. So if you estimate the cost model with and without Toronto Hydro and Hydro One, the parameters don't change very much. A good example is the trend coefficient. There is some variation. In fact, in the updated data, both whether you estimate with or without Toronto Hydro and Hydro One, you still get a trend coefficient of about 1.2 percent per year.

So there is not a lot of variation in the parameters that you get when you omit or include large utilities. So I don't see the argument or the necessity of excluding observations on the basis of size, as has been done in the implementation of the TFP index model.

I think, and this is very important, cost models can better identify forthcoming trends in the industry because they systematically adjust for a series of factors that affect costs. TFP index models relied upon for purposes of setting the productivity factor during third generation incentive regulation, they have not proved to be a good guide.

And what we have here, this is actually from the EDA report in 2008. The line that is quite volatile, actually, traces the productivity factors on an annual basis from, I believe, late 1980s until 2006, and the smooth line is really just sort of a local averaging, a smooth trend. What we were observing in 2008 was that even at that time, the trend was for decreasing productivity factors in US data at the time.

The facile argument is that we have observed what appears to be declining productivity as a result of two major changes since 2008. The first one is the economic problems that befell much of the world in 2008 came to many as a big surprise. The magnitude of these difficulties has not been matched since the Great Depression. This is the closest example of a potentially very major meltdown that we have experienced since the 1930s.

The second easy answer is that there have been shifts in Ontario electricity policy beginning in 2009. I would suggest that these changes argue for greater attention to careful modelling of recent cost trends in Ontario, which are better captured by these cost models, rather than by TFP.

One additional point. I have started to look back at, a little bit more carefully, about when these cost trends began to emerge, and our preliminary analysis suggests that the upward cost pressures in distribution began before 2008. We just didn't have the data in 2008 to recognize that they were there, because we didn't have sufficiently reliable detailed or even consistent capital data, and at that point we were relying on US data.

But now we do have data going back to 2002 that allow us to estimate when these cost changes, trends, pressures began to emerge in Ontario. My point here simply is that our initial analysis - and I have re-run the programs over the weekend using the data that we received on Friday - they suggest that the pressures emerged before 2008.

Let me turn to the inflation factor. Previously, general economy-wide inflation measures were used. Utilities have over the years expressed concerns about industry-specific costs, for example, materials cost. Industry-specific indices tend to exhibit greater volatility. The current report that Dr. Kaufmann has presented proposes to use industry-specific measures and to implement a moving average to smooth the series, and thereby reduce volatility.

The rationale for using an industry-specific factor is that electricity distribution is a very capital intensive business and, therefore, electricity distributor costs evolve differently from general consumer or producer price indices.

And below are the proposed weights assigned to the components of expenditures, and you can see that capital costs dominate. This is not especially surprising that that is the case.

The large share of capital in total costs implies that the inflation factor will be lower than in the general economy if interest rates are stable or falling; will be higher than in the general economy if interest rates are rising.

And this slide in the left column, or the centre column, contains the current three-year industry moving average inflation factor, and you can see that in 2012 it's 0.51 percent. At times, when you compare it to the Ontario annual CPI, which hasn't been smoothed, it's just the current annual CPI, there is considerable discrepancies in certain years.

My understanding is that the low inflation factor at present is due to the decline in the weighted average cost of capital, and I would expect this to continue in the short-term. It is a three-year moving average, and the most recent years in that three-year moving average would tend to put it at this or lower levels, I think, at least for another year.

We have not done a sufficient assessment at this point to conclude definitively whether the proposed mechanism is appropriate, and we will have done so in time for the report.

Utility efficiency rankings. So this deals with stretch factors. And these -- the estimates that are -- the rankings, excuse me, that are being proposed in the PEG report are based on the cost model. The actual assignments to efficiency groups are fairly sensitive to the specification of the model.

We have estimated the cost model using a standard panel data specification. We have not made any significant changes to the structure of the model that is estimated in the PEG report. We have modified the -- this is a little bit technical -- the random structure that's in the residuals. I would be happy to discuss exactly what we did.

In any event, our co-efficient estimates are similar to those obtained by Dr. Kaufmann. Our rankings differ somewhat. There is some migration in and out of the most efficient groups. The so-called least efficient group remains largely unchanged, although the estimated efficiencies are not as extreme as those estimated by PEG.

And the following two slides compare PEG rankings as found in table 11, pages 51 and 52 of our report, to our preliminary rankings based on the earlier data set.

I tried to rerun the programs using the revised data set on Friday, and there appear to be still some inconsistencies in the data. So these are illustrative.

So the left-hand column in this is the identifier for the distributor. I apologize, but the headings have shifted to the left. The middle column in each case is the relative efficiency in the PEG report, and the right-most column is our estimate of the relative efficiency.

And I don't know if it's clear. It's clearer on the screen than it is on my screen here. There should be four coloured panels: A green one, a blue one, a faded peach panel, and then a yellow one.

So the green one -- the green panel consists of the most efficient utilities; the blue panel, the ones that are the second-most efficient, the second cohort. Then the whole sequence of utilities that do not -- are not colour-coded are in the middle cohort, the middle group. The peach one is the fourth cohort, and then the yellow one is the fifth.

Now, put this in an Excel spreadsheet, click the "sort" button for the middle column, you will get this sequencing of utilities. Take that same spreadsheet, click on the column marked "ours", sort that in increasing order, and you get this.

So the purpose of this slide is to illustrate that a relatively minor change in specification of the model, no change in the variables, just a modest change in really the estimation technique for the model, does lead to migration of utilities from one cohort to another.

The yellow cohort seems to be intact. It stays together. Some of the green cohort members stay where they are; others migrate. Even the peach utilities migrate.

The other observation I would make is that in this estimation exercise, if you look at the yellow panel, the relative inefficiency, so to speak, as we have calculated them, those inefficiencies, are generally smaller. In some cases they are slightly larger, in other cases they are quite a bit smaller than they were according to PEG calculations.

Let me underscore once again that this exercise was done using the May 3rd data, not the updated data, because we have as yet been unable to reconcile all the data issues over the weekend.

Let me turn to the peer group analysis. This is a very challenging exercise. Trying to approach the objective of grouping utilities into clusters of similar utilities when you have so many dimensions along which utilities differ, and then basing a relative efficiency analysis on that sort of clustering, that's a very challenging exercise. The assignment to groups can be very contentious.

I think it's a very difficult thing for a regulator to adjudicate and to say, Well, this is the relatively more objective allocation to groups, and that's the relevant one, that's the one we want to look at. And I think it's actually unnecessarily complex.

I also think it's less transparent, rather than more transparent than cost modelling, which simply compares to predicted costs.

Let me point out that the argument that peer group analysis is more transparent is a little bit tricky, because it itself requires you to go back and estimate the cost model in order to arrive at the parameters within this model.

So quite a significant -- certain important modelling and allocation decisions in this process involve the cost benchmarking model as the departure point for selection of parameters to begin with. So to me it's unclear that it provides additional independent evidence upon which stretch factor assignments can be made.

We are still giving careful consideration to the role that peer group analysis could play in the regulatory process. For example, the kind of spatial analysis that Dr. Kaufmann provided, which situates utilities within quadrants, may be helpful to distributors for identifying other distributors that are similar to themselves and to try to understand the reasons why their costs are different. The subsequent unit-cost comparisons may be unnecessary and, as I mentioned earlier, I think potentially contentious.

Conclusions. We have entered a period where productivity growth in the Ontario electricity industry, as measured by conventional variables, may appear to be negative. This is likely because conventional measures do not fully reflect the broader range of activities that utilities are undertaking.

Economic turmoil in recent years has also been an important contributory factor. However, having said that, a greener industry will for the foreseeable future mean a costlier industry, not just in the generation segment of the industry, but also in the distribution, and certainly in the transmission segment of the industry as well.

This is consistent with cost increases in other jurisdictions with ambitious FIT programs. And there is empirical support for that.

The development of Ontario capital and total cost data, as undertaken for this proceeding, constitutes an important step in the determination of regulatory parameters for the industry. Data development is an ongoing exercise. There is continuing need for adjustments and refinements.

However, having said that, especially given the complexities of assembling the data in a dynamic industry - and "dynamic", I don't mean just a forward-looking dynamic as we move to a different policy or have moved to a different policy environment, but the dynamics that have occurred over the last 20 years.

There were many changes, numerous reconfigurations, mergers, acquisitions, and so forth, in the industry. To assemble that data is, in my mind, very impressive. And I think that many contributed to that, the OEB, its advisors, its stakeholders and, of course, utilities.

These data -- and I think we are really very fortunate, because there aren't many jurisdictions that have this level of detail. These data show significant increasing trends in electricity distribution costs. Our best current estimate is that unit costs are increasing in excess of 1 percent per year in addition to the conventionally measured inflationary pressures, and I think it's essential that these cost pressures be reflected in the regulatory regime and the regulatory rule going forward. Thank you.

MS. BRICKENDEN: Thank you, Adonis. I would like to open up the floor for any questions anyone has of Adonis and his presentation. Jay.

Q&A Session:

MR. SHEPHERD: Well, I will start with the obvious one, which Ms. Conboy referred to. Will there be a report, and, if so, when will we see it?

DR. YATCHEW: There will be a report. My understanding, the report is due on June 13th; is that correct?

MR. SHEPHERD: Sorry, your technical report?

DR. YATCHEW: My understanding is the report is due on June 13th.

MS. BRICKENDEN: Written comments, yes, are due on June --

MR. SHEPHERD: Sorry, I am not asking about the EDA's submissions. I am asking about your academic analysis. When is that going to be available?

DR. YATCHEW: My understanding is that the EDA submissions will be my report.

MR. SHEPHERD: So you won't have a separate report?

DR. YATCHEW: No.

MR. SHEPHERD: All right. Then do we know at this point what you are going to propose? For example, you appear to be saying that the formula should be inflation plus 1 percent less a stretch factor. Am I sort of in the ballpark there?

DR. YATCHEW: That's our current thinking, yes. The difficulty in the interpretation I have is that the language of the regulatory rule is that this is a productivity factor, and the appearance that this productivity factor is of the wrong -- the fact that this productivity factor is of the wrong sign would somehow suggest that utilities are being unproductive, are misusing their resources, perhaps sitting around too much, and I don't think that's the case.

And so I have been careful not to use the word "productivity factor" simply because I am struggling with what's going on many this industry. This econometric model has a very convincing trend factor in it that doesn't disappear when I sort of make modifications.

So that number, the adjustment number that you conventionally call the productivity factor, would be in excess of 1 percent.

MR. SHEPHERD: You have re-estimated the PEG models, right -- the econometric model?

DR. YATCHEW: Yes.

MR. SHEPHERD: Do we have that somewhere? Can we look at it, your re-estimation?

DR. YATCHEW: I would be able to provide it. I should point out that one of the reasons I have not actually included that here is because we have had to re-estimate it even -- on the weekend.

MR. SHEPHERD: Understood, and I am not saying it's too late. All I am saying is at some point in the next couple of days, are we going to be able to see it?

DR. YATCHEW: Assuming I can reconcile inconsistencies in the data, let me speak to the EDA, but I have no difficulties with that. I think ultimately I can even provide the code that I wrote. It's written in R- or S-Plus. It's relatively readable as code goes, and it's not very long.

MR. SHEPHERD: Thanks.

MS. BRICKENDEN: Are there any other questions? Dwayne?

MR. QUINN: Yes, thank you, Lisa. Dwayne Quinn on behalf of FRPO. Dr. Yatchew, in your concluding statement number 3, you talk about the greener industry is a costlier industry, and you said there was empirical support from other jurisdictions.

DR. YATCHEW: Yes.

MR. QUINN: Will that information be made available to us, also? If you are making that statement, is there going to be some support for that statement?

DR. YATCHEW: Let me expand on this point a little bit. I have searched and have not yet located data that would allow us to disentangle the increases in costs to the distribution segment of electricity industries arising out of FIT programs.

However, I have done the exercise to look at what's happened to residential rates in other jurisdictions, in certain other jurisdictions, and contrasted those with the share of renewables. Actually, there are a couple of slides out of one of my lectures at the university, and I would certainly be happy to provide that.

These analyses are based on data from the International Energy Agency and can be reproduced. The analysis can be reproduced relatively straightforwardly.

MR. QUINN: That would be helpful. Thank you.

DR. YATCHEW: I probably can show you the slides now if you wanted to see them.

MR. QUINN: Available prior to comment period would be very helpful. Thank you.

MS. BRICKENDEN: I will make note of that, Adonis, and follow up with you. Bill Harper, you had a question?

MR. HARPER: Bill Harper on behalf of VECC. I just want to follow up on a couple of comments that you made, Dr. Yatchew.

The first one is you were saying you used the May 3rd data for the estimation of the cost models when you are redoing your cost estimation models.

DR. YATCHEW: Yes.

MR. HARPER: I know we found out through the stakeholdering process that went on a bit earlier there were some data problems with that that I think PEG has been struggling with to clean up, and I think just recently sort of managed to reproduce a new set of files.

So I was wondering whether the -- I was trying to be sure in my own mind whether the analysis that perhaps you had done using the May 3rd data, to what extent it might be sort of impacted by those same data issues that impacted the earlier results of PEG, and whether or not that's part of what will get picked up in your rerun and we might see some major changes because of that in your rerun that you are trying to do.

DR. YATCHEW: So the main thrust of the argument that I am putting forth here is: What have been the cost pressures in the industry?

Those remain at that over 1 percent level in the new data as of Friday. Now, my understanding, there may still be further adjustments, but the variation is relatively modest. Where there may be substantial changes is in the efficiency rankings, and that is why those colour-coded slides relied upon the older data, because I haven't been quite able to reconcile the data at that level yet.

So there could be substantial changes in the rankings themselves. I also have some issues that I have not resolved completely on the statistical rule that's being used for allocating utilities to cohorts.

MR. HARPER: That's helpful. Sorry, I lost my train of thought. I apologize. I just wanted to pick up on your comment about the 1 percent and that being fairly standard. I understand your arguments about that being continued pressure on FITs and conservation going forward.

One of the areas that seems to me impacts the data over the historical period that we used was the significant amount of expenditures that was made for smart meters, which probably won't be made in the next four years going forward, and could argue would sort of lead to a reduction in cost pressures going forward because we have made this investment.

I just wondered whether, in terms of identifying that as an issue that won't be moving forward, whether you have looked at what the impact of the smart meters was on the trend of your 1 percent. I was just interested in whether you did that or not.

DR. YATCHEW: I have not actually been able to separate the specific impact of smart meters. That's a level of analysis we haven't conducted. What I have done is I have taken a look at what have been the magnitudes of cost shocks in each year, rather than as a trend effect. And there have been significant cost pressures prior to the period of the installation of smart meters.

So I don't see this trend as being driven just by the current programs and the recent economic turmoil. That was something that has concerned me quite a bit, because if it's really just these current events we could argue that, well, we're going to come out of the business cycle, this very deep and extended business cycle, and we will get on a different track with respect to some of these costlier expenditures on the distribution side associated with the Green Energy Act and so on.

There were other instances prior to that that would cause me to worry that that's not all of it.

MR. HARPER: And was this trend variable that you used -- I'll be quite frank with you. I sort of -- this is a change in shift, in terms of when we were looking at Dr. Kaufmann's material, sort of. He used the more simpler approach, and I must admit I didn't spend a lot of time struggling with the economics of how he -- economic models he used, because we used a simpler model, which now seems to be putting more emphasis on the econometric model for doing the TFP.

And is it the 1 percent? Is the trend variable that you used to estimate, is that how you calculate the TFP?

DR. YATCHEW: Yes. Let me also point out again, I have a little bit of difficulty interpreting even the TFP calculations as being simpler and more transparent. In a certain sense, beyond a certain point they are simple and transparent, but that's only because there is a cloth over this cart concealing the mechanics inside. And what's inside is that key parameters of the TFP model are calibrated using the econometric model.

So you first estimate the econometric model, then use certain parameters out of there, and you put them in the TFP model, as I understand it.

So you are already relying on the econometric model to begin with just to get that far. You are also relying on the econometric model to do the unit cost analysis as well, to calibrate certain parameters there.

And yet all of a sudden -- all these other parameters seem to be very important, but this trend parameter disappears, and that's what I find difficult to reconcile, and what I have been struggling with is, what is the source of this significant and materially -- statistically significant and material trend in cost pressures in this industry.

MS. BRICKENDEN: Larry?

DR. KAUFMANN: Larry Kaufmann, PEG. I just have a few questions. On slide 9 -- and you have talked a lot about the trend coefficient, and on slide 9 you say your interpretation is that the reversal is due to slowing growth and sales driving by economic conditions and conservation programs.

I know you are aware that we have sales directly reflected in the model; is that correct?

DR. YATCHEW: Yes.

DR. KAUFMANN: And I am just curious why you are interpreting -- why a measured variable that's in the model is also reflected in the trend variable, which is unquantified.

DR. YATCHEW: First of all, this trend variable is over a ten-year period, part of which is -- encompasses the economic slowdown. There may be that -- it may be that the trend variable is actually picking up some of that effect. If it's not, if all of the sales slowdown is being captured by the sales variable, then the trend coefficient, being as large as it is and the sign that it is, would be even more concerning to me.

DR. KAUFMANN: So you are saying that the direct measure on sales is for some reason not picking up all the impact of the change in sales on conservation?

DR. YATCHEW: That may be the case. I mean, these coefficient estimates are often not as precise as one would like them to be, and I have not conducted sufficient robustness analysis to see when I do vary the specification of the model how much these coefficients differ.

But, for example, when I estimated the deliveries coefficient, it was -- that coefficient was somewhat lower than the coefficient that you had, for example, on tables 10 and 12. So there is some variation there.

DR. KAUFMANN: Okay. I also have a question on slide 26, and that's where you show the differences in rankings between the PEG report and your rankings, and this is a technical issue, but - and I am not going to get into the technical details - but you ran -- your analysis and our analysis were both run on the same data with the same variables, and the only difference was a difference in the assumptions regarding the residual structure and what you called the random structure.

DR. YATCHEW: Yes.

DR. KAUFMANN: And my question is -- and you are putting a lot of emphasis on the use of econometrics going forward to set the productivity factor and the stretch factor, and I am wondering what your opinion is of the fact that the sensitivity of these results is -- as this shows, can be very -- well, the results can be very sensitive to very technical issues about -- between two completely reasonable specifications, but they just differ in terms of some highly technical issues, and whether that gives you any pause about relying on econometrics to develop robust estimates of the productivity factor and the stretch factors.

DR. YATCHEW: Two comments. First of all, this illustrates that there is some considerable sensitivity in group allocation in implementing the slightly different variations in the model.

What I find reassuring is that, while these allocations jump around a fair amount, the trend coefficient hasn't changed. The trend coefficient that I get is quite similar to the one that you get. That I find reassuring.

Furthermore, there are many ways that one can decide on how to establish cutoffs between cohorts. What this suggests to me is that our ability to allocate individuals to groups is much more difficult than the sort of more general problem of actually just estimating a productivity factor.

So here you do see a fair amount of variation, but that's because you are trying to sequence 73 numbers, and it's that sequence that's changed here. When you are trying to estimate a productivity or a cost pressure factor, that's one number that you are trying to estimate from the entirety of the data.

So I do have more confidence in our ability to estimate more general parameters like productivity factors than our ability to allocate individual utilities to groups.

DR. KAUFMANN: Okay. And that's an opinion that you think is linked to reliance on econometrics as a basis for both? Let me rephrase that. Is it your opinion that econometrics leads to relatively more robust inferences on productivity than on relative efficiency among distributors?

DR. YATCHEW: Yes.

DR. KAUFMANN: Okay. Just one final question. And this is on your final slide, where you talk about the regulatory regime and why it's important for that to reflect the cost pressures that are happening in this industry.

I am wondering whether your recommendations regarding how best to reflect these cost pressures -- whether you have given any thought to kind of the bigger picture, and the fact that there is a renewed regulatory framework and there are various options available to distributors to accommodate the cost pressures that they are facing, and what we are talking about here primarily are the parameters that would apply to fourth generation incentive regulation, which is supposed to, according to the Board's guidance in the IRF report, is supposed to be appropriate for most distributors.

I am just wondering whether your general views and opinion about the cost pressures that you have -- that we have both recognized, whether you've considered the overall regulatory regime and whether there are other avenues available to distributors to potentially accommodate those pressures and have those be reflected in their rates.

DR. YATCHEW: Let's say that a utility is given a certain RPI minus X minus stretch factor rule, and let's say that that one is over-constraining, in the sense that it's not realistic in the current cost-pressured environment for utilities to meet those. What's going to happen?

The utility is then going to come in for rebasing at some point, or perhaps take another one of the other options with respect to capital expenditures, and so on, and you will then still observe cost increases that, in some cases, may be more of a cost shock, perhaps even an unanticipated cost impact on customers.

So there are these other avenues, and you do provide the opportunity for rebasing, but if the objective is to try to reflect cost pressures as we see them to the best of our abilities at a given point in time, I think that you'd want to try to smooth those rate impacts over time, rather than wait for discrete jumps that are more likely to occur.

DR. KAUFMANN: My question wasn't really about rebasing, though. It was about the fact that the IRF has more than one -- there is the 4th Gen IR, and then there is the custom IR and there is an annual IR. So there are three different options available to distributors.

Within the 4th Gen IR, there is an incremental capital module. So I am just curious. I wasn't specifically asking about rebasing, but just given the fact that within the framework there are various regulatory approaches, whether that impacts on your recommendations regarding 4th Gen IR and what sort of empirical analysis we should use to set the parameters of 4th Gen IR.

DR. YATCHEW: Let me try to suggest an example from a different industry that hopefully will lead to an answer to the question. If we are talking about the healthcare industry right now, and if somebody went out and estimated productivity factors in the industry there, you would get huge positive numbers.

Why is that? Our simple answer would be the population is aging. It's demographics that are driving these costs. The costs are going to go up.

In the present industry, there are cost pressures, and I think that if you want to have a regulatory rule that captures much of the distributor population in a relatively simple way, one is better off reflecting realistically the cost pressures that they face in that regulatory rule rather than those utilities then having to take the other perhaps more onerous options available to them.

DR. KAUFMANN: Okay, thank you.

MS. BRICKENDEN: Are there any further questions? Dwayne?

MR. QUINN: Yes. Dwayne Quinn on behalf of FRPO. Thank, Lisa.

Dr. Yatchew, I was just considering your response and your willingness, I appreciate, to provide us some empirical data on other jurisdictions.

I just want the make sure, in terms of being helpful to ourselves and to the Board, that these cost increases from these other jurisdictions, these are distribution-related costs increases, or are they actually generation?

DR. YATCHEW: I hope that I was -- I hope I stated this clearly in the previous response. The data at the distribution level is not available. These are broad depictions of what's happened to residential rates in several jurisdictions where there have been forward-looking, ambitious renewables programs. So it's really just residential rates and the share of renewables in each of those cases.

Now, this is just suggestive, and that's why I didn't include it in this slide deck, because it does involve the whole industry rather than just the distribution segment, but I think that it does contain relevant information for us, as well.

MR. QUINN: Well, I will certainly rely on your experience to tell us if this would be pertinent to the discussions at hand. So whatever you have that would be pertinent to the distribution or at least informative, that would be helpful to see. Thank you.

MS. CONBOY: Paula Conboy with the Board. I would like to go back to two of the slides that Dr. Kaufmann took you to, and that's 26 and 25. And if I understand correctly, the differences between the two analyses was model specification, but, in particular, the assumptions that you made on the random factor; is that correct?

So I understand your conclusions and that it's sensitive to the assumptions that you make. What can we take from that? I mean, you are doing more work on this. It doesn't really help me very much in terms of what conclusion I can draw with respect to stretch factors for the industry.

DR. YATCHEW: So one of the conclusions I draw from this simple illustration is that when we speak of 95 percent or 90 percent confidence that so and so is above or outside this central range, it's not really 90 or 95 percent.

So, now, I appreciate Dr. Kaufmann has tried to put a transparent ordering rule in place. Perhaps an alternative would be to simply to order utilities by their ranking and draw lines -- ultimately, there will be some arbitrariness involved -- err on the side of the benefit of the doubt, so to speak, giving utilities the benefit of the doubt where there is some uncertainty as to sort of where they are relative to the line.

So I hope to be able to suggest an alternative or perhaps more than one alternative for how to group utilities. The purpose of this was simply to illustrate that the groupings are quite sensitive.

MS. BRICKENDEN: Cynthia?

MS. CHAPLIN: Cynthia Chaplin. Dr. Yatchew, I have a question back on the trend analysis. Just looking at slide 9 where you make some of your observations, you say normally you would expect a negative trend because of improvements in technology and more efficient use of resources.

So is your conclusion that those things are happening, but that there are other things that are happening that are leading to the trend?

DR. YATCHEW: Yes.

MS. CHAPLIN: Okay. And so from -- is there stuff in your data or in PEG's data that substantiate that there are improvements in technology being -- in other words, that there are some underlying productivity improvements, and where do we see those?

DR. YATCHEW: That is the ultimate puzzle here, because you are asking whether it's possible to identify, in the statistical sense, two effects separately. One of them is productivity improvements on the one hand; on the other hand, the cost pressures arising out of, let's say, to keep this sort of at a modelling type level, what are the outputs that are not being measured here that are excluded, simply because we don't have good measures for them, that are driving costs?

I have asked members of the EDA to at least provide me with a qualitative list of the kinds of activities that they have been involved in that they weren't involved in, let's say, five years ago or ten years ago, but to actually disentangle statistically these two effects I think, at this point, I don't see the data that would allow us to do that.

MS. CHAPLIN: So what makes you so sure that there is the first -- that there is the productivity improvements?

DR. YATCHEW: I guess, to begin with, I think the institutional structure gives me some comfort that there are productivity improvements in this industry, and the institutional structure involves an incentive regulatory mechanism. That's the first thing. The second thing is there are lots of utilities. The third thing is they compare themselves to each other.

So I have reason to believe that the institutional structure is what we want.

On the specific productivity measure side, I don't think that we can assemble variable -- I have not seen variables yet that we could assemble that would be able again to distinguish those two effects. That's certainly worth thinking about.

MS. CHAPLIN: And on this issue of outputs, have you done any -- and I am sorry, some of this may have been done and I am just not aware of it at the moment, but looking at distinguishing customers from, for example, the number of renewable generation connections as a separate and distinct output for a distributor?

DR. YATCHEW: I have not done that type of analysis.

MS. CHAPLIN: I am just in my own mind trying to determine sort of the, oh, there is other outputs and conservation and the FIT program, and trying to link that to distributors. I mean, I can see how FIT programs raise residential rates.

DR. YATCHEW: Mm-hmm.

MS. CHAPLIN: It's not clear to me how they increase distributor costs unless those generators are being connected at the distribution system.

DR. YATCHEW: Certainly there are also the CDM programs that have involved -- that the utilities have been involved in, and we are at this point trying to assemble sort of a list of activities that -- I don't imagine that this will be something that will be quantifiable at this point, in the sense of, at fourth generation...

MS. CHAPLIN: Okay. Thank you.

MS. BRICKENDEN: Are there any further questions? Jay.

MR. SHEPHERD: Yes, I just have one. I am still confused, Dr. Yatchew, about your role here. Are you here as an advocate or as an expert? The reason I ask is, normally an expert will give an expert report separate from the advocacy report of their client, and I don't understand why you are not.

DR. YATCHEW: I believe in the last proceeding I prepared one report -- actually, there was an initial presentation and a subsequent report that I presented on behalf of the EDA.

MR. SHEPHERD: The fact that it happened last time doesn't really help me. The expert reports normally are -- we have a chance to look at them and review them, and it sounds like you are saying we won't see your report until we have already written our submissions, and I guess I am concerned about that.

When will it actually be ready? Maybe that's the better question. When is the earliest date it could be ready?

DR. YATCHEW: At this point, realistically, the time that the EDA's submissions are due.

MR. SHEPHERD: Thanks.

DR. YATCHEW: Please appreciate that we've just received data on Friday that has yet again been revised, and we anticipate changes still in those data.

MS. BRICKENDEN: Before we go along too far, I wanted to remind folks who might be listening in over the Web that they are invited to e-mail any questions they might have to the RRF at ontarioenergyboard.ca account, and we will read them in.

Having said that, are there any more questions in the room? Carm?

MR. ALTOMARE: Thanks, Lisa. Carm Altomare, Hydro One. Just based on what Adonis said about not getting the data in time to improve or update his model, is it possible that the schedule can be adjusted so that we allow Adonis to come forward with the report and, along with that, the updated model, so we can look at this in balance to what Larry has done?

DR. YATCHEW: I did not use the word -- I did not get the data in time. I appreciate the enormous data development effort that has been done by Larry, by the Board, by distributors, and so forth, so I am just suggesting that we are still working with the data.

MR. ALTOMARE: Sorry, I realize that Adonis -- and maybe that was an incorrection (sic) on my part, but realizing that there is a lot of data, I think based on what you're presenting and what you have brought forward would warrant us to be more objective to what you are doing and then what Larry is doing so that as participants and as utilities we can see what are the differences and what are the directions, or at least what is being contemplated.

MS. CONBOY: I think we get your point, and also, Jay, yours is well-taken. And why don't we go back, and we will talk about it among the Board members at lunchtime and discuss it later. Thank you.

MS. BRICKENDEN: Thank you, Paula.

Are there any further questions for Professor Yatchew? No? Okay. Shall we take a five-, ten-minute break, and then we will be up for our next presentation -- the clock is not working. It is currently, I guess, almost ten to. Should we start again at -- all right. Come back at five after?

--- Recess taken at 10:51 a.m.

--- On resuming at 11:14 a.m.

MS. BRICKENDEN: Just inviting Mr. Fenrick up to start his presentation. Steve, over to you.

CLD Presentation by Mr. Fenrick:

MR. FENRICK: Can everyone hear me? Thank you for inviting me, first of all, to this stakeholder conference. For those of you who don't know me, I am Steve Fenrick. I lead Power System Engineering's benchmarking and productivity practice area, as well as the economic studies area of the company. We're based on in Madison, Wisconsin.

I have been at this a number of years, and we'll kind of just go through these slides. If anyone has any of clarifying questions, free to ask them, and then we'll take some questions at the end, just like Adonis did.

So kind of three sections I am going to kind of talk about today, first just provide an overview of what our findings are. We looked at PEG's data set and their work and the data that the Board put together, and did some analysis of our own, so just kind of provide those, a kind of high level overview of our findings.

Then we are going to get into the nuts and bolts, look at the research on the productivity factor, the cost benchmarking, and also kind of get into the inflation factor a little bit. At the end, we will just summarize the recommendations that we have.

So here is the overview of what we are finding. Just looking at the empirical data, looking at the data that the Board put together, that PEG put together, we are really noticing all measures, the different ways that we look at productivity and TFP, that it seems like the industry number is between negative 0.71 percent and negative 1.32 percent, and that really is just based on the empirical evidence of productivity growth, both using the econometric model and the indexing approach.

The second thing is the inflation factor. The RRFE states that it should be industry specific. And so, you know, we wanted to follow that as closely and as best we could, but we feel including the cost of capital into the calculations is really going to make that inflation factor volatile, and Adonis kind of pointed out that 0.51 percent in 2012, that measure is really going to go up and down quite a bit based on interest rates.

So we kind of provide an alternative measure for the Board to consider on an inflation factor that is less volatile, but is still industry specific, still meets the qualifications for that.

The third point is the cost benchmarking, and we will kind of go into the cost benchmarking. We are going to put forth kind of an alternative model that we think is more transparent, simpler to understand. We were able to include a number of more variables into the model, and we think it better accomplishes the Board's policy of promoting efficiency gains and cost effectiveness within the industry. We will get into that point a little bit more, but right now we just believe the current methodology of the benchmarking is really holding distributors to two different standards -- actually, multiple different standards.

If you a larger utility, say you have 50,000, 100,000 customers, you are held to a higher standard than those utilities at 10,000 or 2,000 customers. So there is multiple standards in the benchmarking that we would really think should be corrected. Everyone should kind of be on a level playing field and look at unit costs and not prejudge efficiency gains.

Then the stretch factors, we will kind of put forth a recommendation on what we think the best approach for stretch factors are. We are going to put forth a unit cost econometric model, is what we are calling our econometric model, and we think that really is -- given the simplicity, given that it combines the unit cost indexing and econometric approach, we think this model is robust enough to stand on its own and use it as the sole basis of stretch factors.

All right, kind of getting into the TFP research, again, that's -- as Adonis talked about, that's the indexing and also the econometrics. I am going to kind of use the word "productivity factor" loosely here. What I mean by productivity factor is the relationship between the outputs - customers, capacity, volume - and the inputs, which is capital and OM&A.

So, you know, as Adonis pointed out, there is a number of outputs that we are really not capturing right now and are quite difficult, if not impossible, to capture, whether it's the FIT programs, smart meters, aging infrastructure, all these sorts of things that we are really not necessarily capturing in the model.

First of all, I would just like to say, looking through the data set, this is quite an impressive data set. Gathering the cost data, going back historically, I think that is really useful, really beneficial to Ontario.

To be able to look at productivity trends in the Ontario-specific industry is really beneficial and is really going to be useful for 4th Gen IR and moving forward beyond that.

Just in general, we agree with PEG's calculations for the TFP indexing approach. The data transformations, the assumptions, we kind of looked through those, and we think those are solid and on solid academic grounds, and so we really aren't taking any issue with how they are approaching the TFP indexing approach.

Just kind of a little review -- and, again, this is the May 3rd report. We didn't have time to update our slides when the new data came out on Friday, obviously. So all the numbers here, when I reference PEG's numbers, that is going to be the May 3rd report, and obviously things will have to be updated at some point.

So PEG calculated the full industry. If you look at the full TFP trend of the industry, they calculate a negative 1.24 percent, and then if they take out Hydro One and Toronto Hydro, the TFP goes down -- or goes up, I guess, to negative 0.05 percent. It appears the primary motivation for the subtraction of Toronto Hydro and Hydro One is to have an external measure of TFP. You don't want one utility's productivity to influence their own trend.

And so that appears to be the primary motivation from going to the full or complete industry to one that's less than complete.

I believe there is some merit to looking at an external measure. You don't want a large utility to influence its own productivity trend. That's not an external. That's not really what incentive regulation should be about.

But, you know, in the RRFE, it does call for an industry productivity trend. So we think -- you know, it's our stance that this restriction should be minimized to the extent possible. But, okay, maybe we go to an external measure and externalize it, but let's minimize that impact on the industry, on that industry TFP trend, to the best of our ability.

So what we did is if we systematically exclude, one by one by one, each distributor from the TFP, the industry TFP trend, we do that, so that's certainly an external measure to each one of those distributors when we exclude their own data, and then rerun the analysis.

What you get is a range of TFP index growth rates of negative 0.71 percent to negative 1.32 percent.

And this is really going to found our recommendation that the productivity factor should really be in this range. This is an external measure that includes more of the industry.

So we put together a table. Again, this is using all of PEG's data, the May 3rd data and their calculations, but the only modification being we systematically exclude one distributor at a time.

So on top, for instance, Algoma Power, there we just pulled them, complete industry. We pulled Algoma Power out of the sample. What's the industry TFP trend minus Algoma? And you get my minus 1.23 percent. I just kind of did that on down for all of the distributors.

You see here Enersource. Enersource has the lowest external productivity factor. So if you pull out Enersource from the data, the industry productivity factor then becomes negative 1.32 percent, and then Hydro One is kind of the highest external factor at negative 0.71 percent.

So that's -- if you do this, that's -- all of these observations are within that range of negative 0.71 percent to negative 1.32 percent.

So here is the summary on the TFP index and what we are finding. Again, if you use the full industry, you know, you are including the complete industry, full industry TFP trend; you get a negative 1.24 percent.

Is that an external measure? Hydro One is influencing a little bit. You know, it goes down to negative .7 percent. If Hydro One is taken out, Toronto Hydro is taken out, you know, it goes down to negative .95 percent. Not a huge change, but it does impact it.

On the flip side, if Enersource is taken out it goes down further to negative 1.32 percent. So not a completely -- the full industry isn't a completely external measure, but it's not -- you know, I wouldn't say things vary drastically either.

If you do kind of PEG's recommended approach, where you take out Hydro One and Toronto Hydro from the industry, then you go down to a negative .05 percent productivity factor, keeping in mind now we are only dealing with 60 percent of the industry.

So we make this adjustment, we take out these two large distributors who do our part of the industry, we are down to 60 percent of the industry. So our TFP trend, I don't know if we can consider that an industry TFP trend any more. It's just kind of a small distributor or non-large distributor TFP trend, and that's where we get the negative .05 percent.

Then if we kind of go through the analysis that I walked you through where we systematically exclude one distributor at a time, you know, this is an external measure. By definition we are excluding each utility's data. We are including more of the industry, kind of ranging from 75 percent when -- excuse me. When Hydro One is excluded is 75 percent, versus when the smaller distributors are excluded you are at 99.98 percent.

So certainly an external measure, and there we have got a TFP range between negative .71 percent and negative 1.32 percent. And again, that's what forms our basis for our recommendation.

On to the econometric TFP projections. So PEG in the May 3rd report is recommending -- they recommended a zero productivity factor, kind of on two bases: The TFP indexing, which we just went through, and then also the econometric results found in table 19 and table 20 of the report.

An as Adonis mentioned, you know, this is -- the econometric model could be seen as just as important, if not more important, than the TFP indexing. And as Adonis mentioned, there is this trend variable that kind of has a different sign than what one might anticipate going into the analysis, where you have a positive cost pressure situation to the tune of plus 1 percent.

And so in PEG's table 19 and table 20, they say their econometric model essentially implies a negative .03 percent projection. We believe this is inconsistent with our cost model, that their table -- essentially, their table 19 is not consistent with the econometric model and simply cost theory as well.

MS. BRICKENDEN: Sorry, my apologies, Steve. It turns out we have stopped sharing remotely, so I apologize for the interruption. We are trying to get it hooked up again so that people remotely can follow along with your presentation.

MR. FENRICK: They didn't all go to sleep, did they?

MS. BRICKENDEN: There we go.

MR. FENRICK: Are we back on?

MS. BRICKENDEN: Yes, thank you, Steve.

MR. FENRICK: So again, so the situation essentially is, we believe table 19 in the PEG report is inconsistent with their cost model and cost theory, and when you correct that table 19 you essentially get a TFP projection of negative .97 percent, which again substantiates their TFP indexing and that trend coefficient that Adonis was talking about in the model. It's much more consistent -- the corrected version is much more consistent with all the other indicators that we looked at.

MS. BRICKENDEN: Pardon the break. If we could take five minutes, please, and we will get ourselves up and running. A moment, please.

--- Recess taken at 11:29 a.m.

--- On resuming at 11:31 a.m.

MS. BRICKENDEN: Thank you for your patience. We are now hooked up and I am handing the mic back over to Steve Fenrick.

MR. FENRICK: Thanks, Lisa. So just a review. We went through the TFP indexing systematically excluding one distributor. We kind of found that external measure of TFP to be between negative 0.71 percent and negative 1.32 percent. Again, that's the indexing method, the TFP or productivity factor.

Moving on to the econometric TFP projections which Adonis spent some time on, here PEG is coming up with negative 0.03 percent econometric TFP projection. Again, that is on table 20 of their report, again the May 3rd report.

We believe, when corrected, these cost projections actually lead to a negative 0.97 percent TFP projection, which is consistent again with TFP indexing and with that trend variable in the actual econometric models that Adonis was mentioning.

To kind of get the flows of how this works, table 19 is essentially using the econometric model to project cost, and that flows into table 20, which then figures out: Given that cost projection, what is the implied TFP trend?

We agree table 20 is perfect. We have no problem with table 20. It's table 19 which we think is inconsistent with PEG's model, economic theory, and also the PEG's prior practices for the Board, which were tested and reviewed by the Board back in 2007. We believe they have departed from those practices, and so kind of all that is inconsistent. So we still kind of have a number of questions surrounding that.

We believe the key issue is essentially table 19 omits OM&A input price inflation, and that's the reason they get a negative 0.03 percent TFP projection is because of that omission.

If you kind of go through table 19 in the PEG report, you will notice there is no term for OM&A input price inflation. It shows up nowhere in there, even though in their model OM&A input price is found in the model. In the model variables, it plays a part.

So OM&A inflation could have been zero, could have been 10 percent, could have been 100 percent, and if you run through those calculations in table 19 you are going to get the same exact cost projection of 2.73 percent. Nowhere does it show up in that table 19.

I think all would agree, if wages go up 10 percent or materials and services go up 10 percent, that's cost pressure. You know, utilities, distributors are going to have higher costs when wages go up by 10 percent or 20 percent or even 2 percent.

The average annual growth rate of OM&A input price over this period was actually 2.3 percent. That's calculated by PEG, and that's a good number that we agree with.

What we are leaving out is essentially the cost share of OM&A, which is 41 percent, right around that ballpark of 41 percent, times that growth rate, which is essentially 0.94 percent of cost growth in table 19.

So we kind of have two issues here. The PEG table 19 essentially shows 2.73 percent, which is highly relevant. As Adonis mentioned, he actually puts more stock in the econometric TFP projection, so this is pretty important to get right and make sure everyone is comfortable, all the stakeholders are comfortable with these calculations.

So the PEG table 19 essentially shows a cost projection of 2.73 percent, which implies a TFP projection of negative 0.03 percent.

What we believe the corrected table 19 should show is a projected cost rate of 3.67 percent, which would imply a TFP projection of negative 0.97 percent. And, again, that same difference of 0.94 percent is where the difference is.

We believe the corrected version actually accounts for that OM&A input price inflation over the 2002 to 2011 period.

So I could sit up here and we could go over the math and have a math contest, math debate, which might not be all that helpful for the majority of the people in the room. But what we did, we thought let's just do a -- let's conduct a couple of diagnostic tests, kind of smell tests, if you will, looking at: What number does look more reasonable? What do we think looks reasonable?

So we conducted four tests. And I should mention, in the appendix, I do have some math if people want to -- maybe that would be great for tomorrow or at some point to kind of go over that if people actually do want to go through some of the math. But I thought, for this presentation, let's just look at four tests.

Test 1 is: What's the actual growth, cost growth rate, in the data from 2002 to 2011? What does the actual cost say? One would think with the econometric model, when you are fitting coefficients to actual cost data, you would get somewhere in the ballpark of what the actual data shows it to be. And there you get a 3.74 percent cost growth, if you look at the actual cost data in the PEG benchmarking. Again, that's the May 3rd data. It's probably changed slightly.

So you get 3.74 percent, which I would argue is much closer to the 3.67 percent in the corrected table 19.

The second test is: Okay, what did PEG do back in 2007 in the natural gas incentive regulation? What was their calculation method for TFP projections back then?

So we went back, looked at those tables, looked at that methodology, and basically essentially recreated using that exact same calculation method, but now inserting the 2013 coefficient estimates and the 2013 growth rates for the electric industry, and recreated that methodology. And we will show you kind of those results, what the PEG 2007 methodology would be.

Test 3 is: Okay, what if you now included business conditions? Back in the 2007, they didn't include the business conditions, for instance, the change in percent undergrounding, into those TFP projections; whereas now, in table 19, PEG is looking at those business conditions.

So what if you include those back in and do the 2007 method, but include the business conditions in there? What result do you get?

And then test 4 is -- I was driving home from work, I guess this is probably a couple of weeks ago, and I had some traffic. And I was thinking, What's a simpler method to do an econometric TFP projection? There has got to be a simpler way to do this to project costs than this convoluted way that only economists can really wrap their heads around.

So what I came up with was, essentially, let's just take the average variable values in 2002, just the average values in 2002, put that into the estimated equation. What do we get for costs in 2002? If we take the average values in the industry, what do we get for costs? And let's take the average values in 2011, plug that into the model. What do we get in 2011 for the average values and what's that growth rate? Kind of a simple -- a far simpler way to doing an econometric cost projection, I would argue.

So what does that test show? What's the growth rate in that kind of alternative econometric projection? So we are going to show all four of those tests.

Again, as we said, one would assume that the actual cost growth should match somewhat with an econometric cost projection, if we are doing everything properly. Again, the PEG table 19 shows 2.73 percent. We believe the corrected version is 3.67 percent. And, again, the actual average annual growth rate in costs is equal to 3.74 percent when you look at the actual data.

Test 2 and 3, again, I kind of talked about this before, but in 2007 PEG put forth a report for the Board in the gas distribution industry, and they did the same sort of thing where they are projecting TFP growth using an econometric model.

So if we simply insert now the kind of the electric 2013 model coefficients and the electric variable growth rates into that exact same methodology, we get a negative 0.85 percent TFP growth using that exact same calculation. Just following A, B, C, following that whole math stream, you get a negative 0.85 percent.

I should say not only was this put forth on behalf of the Board, but it was also published in a peer-reviewed journal article by the president of PEG, Dr. Mark Lowry, and also Lullit Getachew, who works with me at my firm.

So here is the table. I am using the 2007 methodology. Again, we took this -- everything straight from the 2007 report and used the same calculation methods, just input the new coefficients in the PEG model and the new growth rates.

As you can see, you get a negative 0.85 percent TFP projection using the econometric model.

If you just go through here, back in 2007 PEG stated TFP essentially comes from two sources, the trend variable, the technology change, which is the negative 1.15 percent, and that's what Adonis was alluding to, kind of the cost pressures beyond inflation and beyond output growth being kind of that negative 1.2 range, you know, 1.4, 1.1, depending on what model you look at.

So there you have that, you know, that influence on TFP is essentially negative 1.15 percent in the May 3rd report. And then you also have this other thing that kind of balances that out a little bit, is the returns to scale. You know, as the industry grows, you can kind of capture -- the distributors can capture some of those economies of scale along the way.

To get to -- I would say, though, to get to a zero productivity those economies of scale would have to be pretty large, with that negative 1.15 trend coefficient. If you actually look at the model coefficients and the output growth over the time using PEG's 2007 methodology, they would say they -- returns of scale essentially added .3 percent to the TFP growth.

And so you simply add up the technology change, add up the returns of scale, and you get that negative .85 percent. We're hard-pressed, and we've been kind of wracking our brains to try to figure out how you go from that negative 1.15 percent to zero, with only returns to scale or business condition changes, and so we have been kind of unable to figure that out.

If you include the business conditions, which I haven't put on this table, the TFP projection goes down to negative .93 percent. So if you include, like, the change in percent undergrounding, I think is the one big change -- or not really big change. It adds .08 -- you get a TFP projection of negative .93 percent.

In that alternative approach, kind of the traffic-jam approach, where if you take the 2002 average of all the variables, plug that average into the model, you basically get a cost prediction at that average utility distributor of 37.1 million in 2002.

Do that same thing in 2011, take the average of all the variables in 2011, plug that into the model, you kind of say the average distributor should have costs of 51.4 million, according to the model, do the math, and that's a growth rate of 3.63 percent. And then, you know, if inserted into table 20, PEG's table 20, if that new cost projection was inserted in PEG's table 20, you'd get a negative .93 percent TFP projection.

Here is kind of the summary of our tests. Again, we are kind of trying to decide, you know, what is the appropriate measure, the econometric result, what is the econometric TFP result. You kind of that negative .03 percent in the PEG May 3rd report, versus the negative .97 percent, which we think is the corrected, most appropriate, proper version to use.

And you have got the four different tests there, you know. Test 1, again, I think aligns much better with the kind of that ballpark of negative 1 percent TFP productivity. PEG's 2007 method again was in that ballpark of negative 1. If you add the business conditions, test 3, again the ballpark of negative 1, and if you kind of use that simpler econometric cost-projection approach, that again applies, kind of in the same ballpark of negative 1 percent.

So that's the TFP portion, kind of moving into the inflation factor research. We kind of looked at PEG's recommended approach, and we are still sorting through some things, what that might look like. It did show quite a bit of volatility. And as Adonis pointed out in the previous presentation, in 2012 that .51 percent with the three-year moving average, where the inflation factor would be .51 percent, you know, if you add that to -- subtract out a .1 percent productivity factor and then take the stretch factor off, you know, some distributors likely would have rates that would decline using this methodology and the productivity factor that PEG put forth.

Moving forward, with a three-year moving average, this really does amount to a rate-freeze plan for the next year to two at least, maybe two to three years, and then, you know, if interest rates or inflation shoot up, I mean, you could have a rate freeze, and then, you know, prices that skyrocket as well. You know, it can work in both directions.

And so, you know, this has some volatility, so we kind of thought about this a little bit, and what would make -- what would be a plan or alternative inflation factor that we think would make more sense for the Ontario industry but still be consistent with the renewed regulatory framework, be industry specific, I mean, all those sorts of things.

The key reason why the volatility in the recommendation is because the cost of capital is in there. And so you have the interest rate changes over time, and that can lead -- can tend to have higher fluctuation and also lead to double-counting inflation.

A lot of times interest rates and inflation will be moving in the same direction. Right now they are low. Historically speaking, interest rates are low, and so is inflation. You know, that could turn around and they could both turn around, so you don't really want to double-count those types of things.

In Alberta PEG put forth -- they were working for the Consumers Coalition of Alberta, and so in the Alberta performance-based regulation initiative they kind of took a stand against including cost of capital in the inflation factor, and for the purposes -- or for the reasons cited in this quote here, you know, it could lead to fluctuation, double-counting, those types of things.

So what did PEG propose in Alberta? Just like here, is a three factor index. There is a non-labour component, which is that they put forth the GDP-IPI; a labour component, the average weekly earnings; and then the capital component.

But here is where the difference is. Rather than including the capital service price index, which PEG is recommending now, they put forth what's called the triangulized weighted average of the electric utility construction price index, and that kind of sounds complex, but all it really is is a weighted average of the asset prices historically.

So what have utilities been paying for their assets, going back 40 years? What have those prices been, and can we wait? Can we just wait? How much is left of each one of those assets? Weight that up and what's that price, what's that capital price.

So essentially what is the price in the rate base that electric utilities have faced from a historical perspective. That's what PEG proposed in Alberta, and we think it makes a lot of sense here in Ontario. You know, it's -- again, it's industry-specific, captures the three factors of non-labour, labour, and capital.

And again, the only real difference relative to what PEG is putting forth is the capital component. We kind of like to strip away those costs of capital changes, because that's where the volatility is coming from, is those costs of capital changes, and just move to a weighted average of the prices paid for assets that are now in the rate base, just kind of weight that up, looking historically.

So, you know, why is this inflation factor appropriate in the Ontario context? Again, I mentioned this a couple times. It's industry-specific. Far less volatility than the PEG recommendation. You avoid any issue of double-counting interest rate and inflation measures. It's actually a simpler calculation, even though the name might not suggest it. We can come up with a better name, maybe.

But, you know, the calculation is -- the PEG capital service price, this is actually a subset of that whole calculation. You know, this is in there, if I am not mistaken, and so it's just kind of a subset of what's been put forth. So it's actually a simpler calculation, and we can actually use the annual number. It can be more relevant or more current than needing to smooth it over three years due to the volatility.

Here is how you would actually calculate it. I kind of won't spend too much time on this slide, but you can kind of see -- go back 40 years, so in the current year, year T, the measure is essentially built up over kind of a 40-year period.

So in year T minus 40, kind of that top row, the EUCPI value is 24.1, for instance, but you would see in that current year kind of one-fortieth, you know, that capital that the utility put in 40 years ago, about one-fortieth might still be around, kind of that one-fortieth amount, whereas year T minus 20, the next row, you know, about half of that capital is still around after depreciation, and so you just kind of add all those up and weigh it, and come up with a weighted average to come up with that TWA price. That's all it really is, is just a weighted average of the historical asset prices put into the rate base.

So kind of looking at the summary of the inflation factors, you know, 3rd third Gen IR was using the GDP-IPI, and you kind of see those values there along with the standard deviation, and the standard deviation was essentially .39 percent from 2006 and 2012.

PEG's recommendation, you can kind of see a little bit more volatility going on. You are also averaging over three years to smooth. You still have higher volatility, higher fluctuation.

The -- our recommendation, still three factors, still industry-specific, but using the TWA calculation, and just on the annual basis, your table is slightly lower standard deviation than what was used in 3rd Gen IR, and so you have a little less volatility with this index.

And you will notice that index does tend to be higher than GDP-IPI during this period, but there is no guarantee that if interest rates and inflation start to pick up in 2015, 2016, whenever that might be, given that standard deviation of PEG's recommendation, you can have essentially a rate freeze for the next couple of years, and then price shock future years.

I am no macro economist projecting the future, but that certainly could be one scenario that could occur. So we think this is a much more stable index and industry-specific, as well.

Moving to the cost benchmarking, so that was the inflation factor research that we did, the cost benchmarking. So we kind of took a step back, took a step back and said, Okay, this model, this framework during 3Gen IR was certainly cutting edge, certainly better than most jurisdictions around the world, but how can we improve it? How can we improve this framework.

So we kind of took a step back and said, How can we improve this? We found kind of -- we would like to put forth a new alternative that we think accomplishes six things. It's kind of far easier to understand and explain rather than -- a lot of people with econometric model that currently exists and is in the May 3rd report, there is a lot of thing there; it is kind of a black box in a way that a lot of people don't exactly know what's going into there.

Can we make it simpler? Can we simplify things, but still get a good result out? We would like to make it neutral rather than disincentivizing distributors for efficiency gains of increasing in size.

I will get into this. I have a couple of slides -- kind of show the current PEG proposal for the model essentially provides disincentives for efficiency gains, and we think this is kind of contrary to Board policy as far as incentivizing efficiency gains, incentivizing cost effectiveness. We kind of walk through -- you know, walk through that and how our model is neutral.

And I know everyone is on the edge of your seats for those slides, but, essentially, if you have a distributor that is 100,000 customers versus 10,000 customers, there is two different standards. That 100,000 customer distributor is being held to a higher standard, a much higher standard, than those smaller distributors. The same thing for a 20,000 versus a 10,000. There is two different standards. That 20,000 distributor is being held to a much more challenging cost benchmark than that 10,000 customer distributor, and we just think that provides disincentives to accomplish the things that Ontario has set out to accomplish.

The third thing is we thought with a new -- with 4th Gen IR we would really like to make it easier – quote-unquote easier -- for distributors to move between the stretch factors. We think that would increase the efficiency incentives. Right now a lot of distributors kind of feel trapped. Due to the peer group approach and, to a lesser extent, the econometric approach, they kind of feel trapped in their cohort group. Like, there is no way we can get out of here.

We would like to increase the ability for distributors to move both up and down, because I think that would just increase the incentives and kind of benefit all stakeholders.

This new methodology provides key information to managers about the cost levels and how high are they in actual dollar terms, kind of unit cost dollar terms? Can we simplify this? Can managers actually know what's going into this black box so they can manage towards it and actually have a hope of moving between the stretch factors?

We also increased, I would actually say substantially increased, the number of business conditions variables in the model. So we believe -- I believe we added five different variables in the model that -- so we think this a much more accurate depiction of performance.

And we kind of show that because it has tighter results. You know, you don't see the huge range. In the current PEG model, you have from minus 60 percent to positive 60 percent. We have kind of tightened that down with this new model so we are more accurately portraying the cost levels of distributors.

And we think this alternative approach essentially eliminates the need for the peer group or unit cost indexing approach. We have sort of combined the two approaches into one approach, so we believe this alternative approach eliminates that need.

Just kind of walk through some of that stuff that I just talked about. We took the unit cost indexing. That's kind of an intuitive concept, unit costs, costs per customer. That's seen within the industry, both the electric industry, gas industry, and we combine that with the econometric approach into one benchmarking framework. We kind of call it the unit cost econometric benchmark or model.

Looking through the PEG data and the cost data and the variables that they put together, there is some grey areas. Experts can disagree should this cost -- can contributions in aid of construction be included, low voltage, et cetera, et cetera. You can kind of debate those types of things, but, in general, we thought those are kind of grey-area issues, and we didn't really want to get into those types of -- we are kind of fine, especially now with the correction with the low voltage.

So we kind of used PEG's exact cost data in this and the variables they put together. So we didn't change any of the underlying data, cost data, if you will.

We did add a couple of business condition variables into the model that weren't there previously.

So what does this model look like? Kind of getting into what the unit cost model looks like, all we are doing is simply saying costs per customer. So you have costs per customer and that is driven by or equals -- is a function of a number of variables. Kilometres of line per customer is one variable.

So cost per customer equals kilometres of line per customer, peak capacity per customer, area per customer, customer growth and a time trend. Those are all areas that are currently in the PEG model.

Since we simplified the model, we took out kind of the prejudgment of economies of scale that was in the model. That allowed us a whole bunch more degrees of freedom, much more explanatory power of the model so we could get a number of other variables into this framework.

We put a wind variable in. That's kind of windy conditions. So we mapped all distributors to the nearest wind weather station and looked at hourly wind data and created a wind variable. So obviously distributors that are facing more windy conditions off of one of the lakes, or those types of things, are going to have higher challenges. They are going to have to construct more robust assets. They are going to be dealing likely with more outages, which is going to drive up cost. So we put that variable in the model.

Load factor we put into the model. A utility with a higher load factor is going to have lower cost as their load is flatter versus a more peaky system. Distribution transformers per customer, as you have more transformers on the system, and as your system just needs to be configured to have more or less transformers per customer, that is going to drive up cost.

Percent single-phase lines, distributors that are able to have all single-phase lines are just naturally going to have lower costs than those distributors with three-phase lines. Three-phase lines are substantially more costly to construct, and so we have a variable for single-phase lines in there.

And we are also able to get an age variable in there, as well, which is defined as the accumulated depreciation divided by gross plant. So we were able to get an age variable in there, you know, how old is the system, and then age squared, which is kind of a really interesting finding.

Age tends to decrease costs up to a limit, and then when you get to a certain point, age actually increases cost. So we kind of have that variable in there, as well, and then the time trend which is in there.

The kind of variables we didn't have the time to gather or aren't available is that percent embedded KW for the host distributor and the embedded distributors. Right now the cost definition has those low voltage costs in there, but there is no -- the cost drivers, the KW or the KM of line that is driving those costs, that's not actually in kind of explaining those costs.

So, ideally, it would be nice to have a variable that adjusted for that or controlled for that kind of miscongruity between the costs and the cost drivers.

And also forestation variable using GIS, if we had more time, we could attempt to try to get that forestation variable in there and look at the canopy issues and forestation of distributors, but given the tight time lines, there is just not time to get that in.

So kind of keep it simple. This model is simply looking at cost per customer and explained by a number of factors. So there is no natural logs in here, no interaction terms, no quadratic terms, just variables and their impact on cost per customer. It's all in dollar terms.

If you see the equation down below, that's essentially the equation that we're dealing with. You know, cost per customer is equal to A1, which is a constant, plus A2 times peak times N.

So for instance, you know, peak divided by N, you know, this is kind of an unrealistic value for this variable, but say it's 1, just assuming, you know, peak divided by number of customers equals 1.

That would say that the cost per customer is expected to increase by the value of A2. So whatever the regression model says A2 equals, you just times that by that peak divided by number of customers, and that's what that variable is contributing to the benchmark.

So a distributor then maybe has double the average of peak divided by customer, is basically going to have two times A2 of unit costs, of costs per customer, into the benchmark.

So you kind of see, you know, this is a lot more straightforward, and you can see the impacts of each of the variables. Distributors can actually go in, know their variable values, plug in, and kind of see, What is driving my cost benchmark? Where is that driving? What's going on here?

And actually, if I just skip to that slide right there, for the average impacts of each variable, so this is at the average, if you take the average of all the variables, this is what each one of those variables is contributing to the unit cost, which were defined as costs per customer. So you kind of see at the average, peak divided by customer is contributing basically $125 to cost per customer. You know, distributor that maybe has double that variable value, so kind of double peak divided by N, you know, essentially, their peak is going to be costing them, you know, $250 in costs per customer, and you kind of go down the line and look at each one of those -- each one of those values and kind of see what it's contributing for each individual distributor, and this is kind of at the average of the values.

Just backing up one slide, there is the model. You kind of see again, we are just trying to explain cost per customer. So cost per customer, and then here is the variables that go into that.

And these coefficients are simply -- can simply be defined as, the variable value goes up by one. This is how much the costs per customer is going to go up. So capacity divided by N, if that goes up by 1, the unit costs is expected to go up by 29-point -- $29.53 is essentially what that is saying.

And all these variables -- I should mention all these variables are statistically significant at 99 percent confidence level. So we have added five new business conditions, all significant, at a 99 percent confidence level. There is that table.

I also alluded to the fact, you know, our range of scores has kind of drastically improved over PEG's methodology. We have a range of negative 31.7 percent to positive 42 percent, kind of in the cost of the unit cost evaluations, compared to -- and again, this is the May 3rd report -- a range of scores from negative 64 to 69.2 percent. So we have got a much tighter range, which I think should enable distributors if this alternative is -- if we go down this road, will allow distributors to move more easily between cohorts. There is not the huge gap in cost between the distributors. So, you know, it's going to make it easier to move between one ranking to another ranking.

Okay. Here is the part where you are all on your edge of your seats, I am sure, kind of incentives for efficiency gains. We really think this unit-cost econometric model better aligns itself with the Board's objective of promoting economic efficiency and cost-effectiveness within the distribution industry.

You know, and I could talk about that more, but I thought a simple example might illustrate that point. So if we just assume there is two distributors out there, they're average -- average distributors, you know, average size, average cost, average business conditions, just two average distributors, and say they are sitting out there, and, like, Hey, maybe there is come cost efficiencies if we merge. Maybe we should -- you know, our service territories are somewhat close to each other in proximity. Let's merge. There is cost efficiencies there.

One would think if they actually do find cost efficiencies, the benchmark evaluation should show an improvement. You know, if they find those cost efficiencies, customers benefit from finding those cost-effective efficiencies, kind of those synergies, that they would move up the rankings.

Now, if we use the unit-cost econometric model, PSEs, that's exactly what would happen. Pre-merger, that kind of that average distributor, their 2011 unit-cost benchmark would be $723.19, so that's their cost per customer, would be -- you know, that's their benchmark. You know, if they beat that, they are above average; if they don't beat that, they are below average.

Post-merger, you know, so these two average distributors come together, merge, so they are going to have twice the size, but all the same, you know, percent undergrounding is going to be the same, kind of all those same business conditions, but they merge, so they double in size. Again, the benchmark is going to be the same, again, $732.19, so they are not going to be held to a different standard than when they were separate.

So any efficiency gain that they might be able to find, say they're able to find $10 million in efficiency gains, that is going to be reflected into the benchmark ranking. Their benchmark is actually going to improve, and they are going to move up the rankings and maybe move up the cohort groupings.

So there is kind of incentives there. If we can find those efficiency gains, customers gain. Let's find those and move up the rankings. You know, we think that's -- this model is neutral to that. You know, if they find them, great. It's going to be put into their score. If not, you know, that's -- there is going to be no change.

Now, if we flip it to kind of the current methodology in PEG's proposed approach with the econometric model, again, kind of same exact situation. Assume two average distributors, and they decide to merge. Again, they are exactly average in the industry, as far as all their variables are concerned.

Pre-merger, kind of looking -- and we did the calculations. If you look at their 2011 total cost benchmark, would equal 51.4 million. So for this distributor, distributor A, their benchmark is 51.4 million, so that's their benchmark, so that's what they have to be to become an above-average distributor, and this one here, also average, their benchmark is 51.4 million using the PEG benchmarking model.

So say they come together. What's the new benchmark with this distributor that -- double in size, but all the other business conditions stay the same? The total cost benchmark now goes down -- it goes up to 88.6 million, but that's not 51.4 million and 51.4 million added together. They are actually held to a higher standard now that they have merged, and so essentially the PEG benchmark is taking away 14.2 million in efficiency gains. Rather than adding 51.4 million and 51.4 million and coming up with 102.8 million benchmark, now the model is basically pre-judging what those efficiency gains are and saying, Well, you should find 14.2 million in efficiency gains, and now we are going to hold you to a more difficult standard now that you have merged.

And so say in this example, a utility -- these two utilities only find 10 million in efficiency gains. You know, that's going to benefit customers. That's going to benefit the province. You know, that makes the industry more efficient, you know, finding those 10 million. But in this example they would actually decline in the benchmarking rankings, given the current methodology. Their benchmarking ranking would actually go down. They could possibly move to a much -- a worse cohort where the stretch factor is more difficult, and also in the peer grouping approach it might push them into a new peer group that's more challenging as well.

So for all these reasons we think the current proposal out there is providing disincentives for distributors to uncover these efficiency gains, you know, through mergers. And it's just holding distributors to different standards throughout the province, and we think there should be one consistent standard across all distributors.

Okay. Just finishing up here.

This just shows the results when you use the unit-cost econometric model. You kind of see unit-cost benchmark, unit-cost actual, and then the difference. So you just kind of get a flavour for what would pop out of here. Again, this is all in dollar terms, so people can -- transparent and see what they have to do to move.

And one caveat to all this is there is one distributor, Toronto Hydro, that we know is kind of ill-served by using Ontario-only data set, you know. Given that they serve the only urban core, really the only urban core in the province, and they are essentially an extreme outlier along with Hydro One, you know, there is really no fair way to use an Ontario-only model to depict their performance, because you can't get an urban core with only one observation in there, and any econometric model. Whether it's the unit-cost econometric model or PEG's econometric model, you know, the centre of gravity of that model, given Ontario-only, is going to be right in that small distributor range of 30, 35,000, 40,000 customers. It's very difficult, if not impossible, to extrapolate that to a utility that has 700,000 customers.

So you just kind of get -- it's ill-suited for -- in Toronto Hydro and Hydro One's case, especially Toronto Hydro, given that they are serving an urban core and those cost pressures can't be accounted for.

A possible solution for Toronto Hydro would be comparing them to US data and putting in an urban core variable. I just show this. We have done work for Toronto Hydro last year and into this year, and just when you compare them to the US model, you get drastically different results, simply because you can put an urban core variable in there and those distributors are of like size and have kind of similarly-situated circumstances.

And so there you get kind of 14 percent below total costs for Toronto Hydro, whereas in the econometric models that PEG put together and also ours, they are kind of -- a different story is being told.

So under the recommendations, it shows a picture. That's my three-year-old. I love that picture.

Back to the productivity factors, we simply think all empirical evidence shows that that ratio between customers, volumes, capacity and those inputs, that ratio, that productivity ratio, is declining throughout the 2002 to 2011 period by -- in the ballpark of negative 1 percent. Both the TFP indexing and the econometric TFP estimates seem to show that this is the case throughout this period.

Again, if you go to the external TFP trends, you are kind of in the range of negative 0.71 to negative 1.32 percent, with the full complete industry at negative 1.42 percent. So kind of on this basis, our recommendation is a productivity factor in that external range of negative 0.7 to negative 1.3. We think in that range is kind of what -- an appropriate productivity factor that aligns itself with the actual empirical evidence that has been shown and all the data that's been gathered on the capital and all those types of things in the province. That appears to us to be what the data shows.

Inflation factor, again, using that TWA calculation, the weighted average of the asset prices, that's going to be less volatile. It's going to be more transparent, and it doesn't double count the interest rate and input price inflation. But, at the same time, it still accomplishes the objectives of being industry-specific, stable and reflective of the historical asset costs of the industry.

On this basis, our proposal or our alternative is to basically use what PEG recommended in Alberta, except substituting the Ontario indexes or Canadian, depending on the scheduling, and using that TWA approach.

Cost benchmarking, we believe that unit cost econometric model is more intuitive. It's simpler and includes many more explanatory variables that increases the power of the model. And it also is neutral or rewards distributors when they find efficiency gains and benefit the customers.

So we think this model should be used kind of as the sole basis of evaluating stretch factors going forward in 4th Gen IR.

Stretch factors, you know, using the unit cost econometric model I think is going to enhance the ability of distributors to move from one cohort to another cohort, and thus one stretch factor to another stretch factor. It's going to do that -- eliminating the unit cost indexing approach, which does trap, quote-unquote, trap a number of distributors and kind of makes any sort of cost cutting irrelevant from a regulatory stretch factor perspective.

It's going to substantially increase the ability of distributors to move from one cohort to another, and the type of range of the unit cost econometric model is also going to make it easier to move between the cohorts in the stretch factor rankings.

We recommend using, on the sole basis, the unit cost econometric approach, with the range of stretch factors kind of going from zero to those top distributors on down to a 0.5 percent stretch factor.

We kind of lay that out here kind of separating the distributors into six different cohort groups just dividing 73 by 6, and then adding one extra somewhere. Kind of number 1 through number 12, we get a zero percent stretch factor, kind of saying, you know, that, Hey, those are the distributors that are in top of the industry. They appear to be most cost efficient. We are not going to give them any stretch factor. They are going to try to hit that average productivity trend, productivity factor in this industry, and we are not going to put any added productivity expectation on them, and moving on down in increments of 0.1 percent on down to 0.5 percent.

Summary of recommendations, productivity factor, negative 0.7 to negative 1.3; inflation factor, using that the three factor TWA approach; cost benchmarking, unit cost econometric model; and those stretch factors as I just laid out. That's the end of my presentation.

MS. BRICKENDEN: Thank you, Steve. Any questions, sorry, Larry.

Q&A Session

DR. KAUFMANN: Actually, I have a number of questions and I don't want to use up anyone's time before lunch, but I do have -- rather than questions, I have two factual statements I would like to make in terms of correcting what was said about PEG's previous work.

On slide 24, slide 24 says that what PEG proposed in Alberta does not include cost of capital changes. That's not true. That recommendation does include cost of capital changes. In fact, it's identical. It's the weighted average cost of capital that we proposed here. So that's factually incorrect.

On slide 22, this quote from Mark implies that he believes that there is double counting when you include cost of capital changes in an industry-specific inflation factor. And, one, that's -- and this is from the same proceeding. I mean, that's obviously not the case, because he did propose that, but if you look at the transcript here and you look at the context for this quote, what you see is what he is referring to is that there are two elements of the adjustment mechanism that they are talking about.

One is an industry-specific inflation factor, just like we are proposing here, and the other is a Y factor. One of the companies there, ATCO Gas, proposed an inflation factor and a Y factor or a pass-through to reflect financing rate changes.

So that was the reference to the double counting, very different. That's not the issue here.

So just to correct the record there, both of those slides are factually incorrect.

MS. BRICKENDEN: Thank you, Larry. Are there -- Jay, you have a question?

MR. SHEPHERD: I actually have four questions. And I am not an economist, so that's sort of my indirect way of saying give me a break.

MR. FENRICK: I play one on TV, so...

MR. SHEPHERD: Let me start with your calculation of the external TFP where you do 73 runs, right, and you take out one utility in each one so that they are not self-referential; right?

MR. FENRICK: Right.

MR. SHEPHERD: Tell me whether this is right, that what the data shows quite clearly is the dominance of Hydro One and Toronto Hydro, because those are the only ones that are outliers on the list; right? They are all between a very narrow range except for those two.

MR. FENRICK: It depends on how you define "narrow range". So, yeah, Hydro One, when you exclude them, the trend then becomes negative 0.71 percent, and Toronto Hydro is negative 0.95 percent. That's kind of within the range of our -- that's why our recommendation range is between those two --

MR. SHEPHERD: My question was a different one. For all the other runs, the ones that include both of them, they are between 1.24 and 1.32; right?

MR. FENRICK: Correct.

MR. SHEPHERD: And it's only the ones where those two are taken out that they are outside that very narrow range, and the right conclusion from that is that they are dominant; right?

MR. FENRICK: That they are what?

MR. SHEPHERD: That they are dominant.

MR. FENRICK: Yes, certainly. I mean, Toronto Hydro and Hydro One are part of the industry. If you took -- if you took 20 distributors at random and added them up to where they equal Toronto Hydro and excluded them, I bet you would have a different TFP industry, TFP calculation, as well.

Just because Toronto Hydro historically has merged six distributors into Toronto Hydro, I don't think that's any reason to exclude them, just because if you look at 20 or you look at ten and take them at random, yeah, it's going to change. They are part of the industry.

MR. SHEPHERD: The difference between your model and Larry's model in this is that you have removed one-seventy-third of the impact of Toronto Hydro and Hydro One, and he has removed all of the impact; is that right? Mathematically, is that right?

MR. FENRICK: I don't believe that would be the right way to think about it. One-seventy-third of the impact to Toronto Hydro...

MR. SHEPHERD: Yeah, because you do 73 runs and you only remove them in one.

MR. FENRICK: Right. So in that one, right, they are removed in that one, and the rest of them they are in, if that's what you're saying. Yes, so out of the 73 runs, Toronto Hydro is in there 72 times out of the 73 runs.

MR. SHEPHERD: Then the second thing is, my second question is, you are talking about Larry's table 19, and I am not sure I understood what you are saying. Are you saying that there is an error in his calculations?

MR. FENRICK: Yes.

MR. SHEPHERD: Okay. Then the third question is, you talked about your technique number 4 for applying a smell test. You said you averaged the variables in 2002 and 2011. Is that a common practice to do that?

MR. FENRICK: None of this is really common practice.

MR. SHEPHERD: Would I find that technique in the literature somewhere?

MR. FENRICK: No, of course you wouldn't find PEG's table 19 technique in the literature, if I am not mistaken, anywhere either. So this is kind of just a simple test to look at, okay, what would the econometric model say if you average 2002, average 2011 --

MR. SHEPHERD: I am just trying to understand the theoretical basis for using averaging as if it tells you something, and I am not sure I understand why averaging would tell you anything.

MR. FENRICK: I think it tells you what the econometric model says, as far as what its average cost expectations are, both in 2002 and 2011, for that average - "average distributor". And I would add, the only thing that actually has shown up in the literature that I am aware of is the 2007 PEG method, which actually has shown up in a peer-reviewed journal article, and we showed those results.

MR. SHEPHERD: But that didn't use averaging either.

MR. FENRICK: No, that didn't use that test --

MR. SHEPHERD: And the econometrics normally don't average the variables, right? You wouldn't normally do that.

MR. FENRICK: It depends on what you are trying to figure out. If you are trying to figure out what is the average cost for the average distributor, you would.

MR. SHEPHERD: Okay. And then my last question is, on your cost benchmarking you said you got rid of all logs and quadratics and other more complex relationships. Am I right in understanding that the result of that is that you have assumed that the relationship between every business condition and cost is linear?

MR. FENRICK: Yes, I believe that's -- except for, we have an H-squared variable in there, but that's the only exception.

MR. SHEPHERD: And is there some reason to believe that that's true, that the relationship between business conditions and costs is always linear?

MR. FENRICK: It's --

MR. SHEPHERD: Sorry, is there something in the literature that would tell me that?

MR. FENRICK: I mean, I haven't done a full literature review. I am sure there is a number of models that are out there in the literature review. I mean, these are types of industries that have been studied, well-studied.

I would say, you know, if you do a literature review, you are likely to find the translog cost function much more prevalent that the PEG is using. You know, that is much prevalent in the literature, because usually the literature is trying to figure out, what is the impact of the economies of scale. They are trying to figure out what -- how do number of customers impact costs, you know, how do the different interactions of the variables impact costs, so --

MR. SHEPHERD: And those are not always going to be linear.

MR. FENRICK: And those are not always going to be linear, exactly. But in this context, where we are trying to incent efficiency gains, incent cost-effectiveness, and incent utilities to find cost advantages that they can pass on to customers, you know, we need a different model than what's in the literature. You need a model that levels the playing field and doesn't take account of those non-linearities in the variables, because when you do account for those you get different standards across the province, and one distributor is being held, you know, just like that example I showed. One distributor is being held to a higher standard versus the other one.

So, yes, you are taking away that which is in the literature, but I think you are doing it for a purpose. You are doing it for the purpose of coming up with a fair model that treats all distributors the same across the province.

MR. SHEPHERD: You are removing economies of scale, basically.

MR. FENRICK: Yes.

MR. SHEPHERD: Your client is the CLD?

MR. FENRICK: Correct.

MR. SHEPHERD: Thanks.

DR. KAUFMANN: Can I just follow up quickly? When you remove economies of scale, what you do is you assume constant returns to scale for all companies in the industry, correct? You are imposing that restriction on all companies. Yes or no?

MR. FENRICK: Yes.

DR. KAUFMANN: Okay.

MS. CONBOY: Are there any additional questions? Bill?

MR. HARPER: Bill Harper for VECC. I had three. Thanks to Jay I now have two questions.

The first one has to do -- and maybe with Mark's clarification it isn't an issue any more, but you are basically proposing a different capital price escalator which -- and I was wondering, like, in both the -- in the cost estimation model and in the TFP indexing analysis that PEG did, I mean, the price escalation, including how you formulated the capital price escalation, was -- was inherent in both of those, in terms of helping to determine what the quantity of inputs was and what the -- relative to the quantity of outputs, and I guess I was wondering, because in your analysis you relied on PEG's -- and your comments, in terms of TFP, you have relied on PEG's analysis, which views their definition of the capital price index, and I was wondering, if you would change the definition of "capital inflation" that was used during -- for the historical period, wouldn't that change all of the TFP analysis that was done, and you'd come up with a different set of results? And if that is the case, based on your recommendation, would it be appropriate to do that, given that you are proposing a different capital price escalator going forward?

MR. FENRICK: Let me try to tackle that question. So in the TFP indexing, for instance, you are looking at the ratio of outputs to the ratio of input quantity, and so in that input-quantity calculation is -- you start with the benchmark year, which is that TWA value, and so that is your starting point for the quantity, the capital quantity, and then you build it up using kind of the EUCPI changes and planned additions, but nowhere in that quantity does the rate of return show up.

The only place it does show up is in the weighting. So how you weight the capital quantity and weight the OM&A input quantity, how you weight that, that's where it does show up. And so I would suggest probably if the Board wanted to move to this, you know, maybe change those weights. I don't think it's going to change the result too much. You are just kind of changing -- my guess is you could have a 62 percent weight now, and it's going to be 61.5 or, you know, 63. Anyway, I am not going to take a guess, but it's going to tweak it slightly. But that's the only place where that would show up. I think that -- does that answer...

MR. HARPER: Yes.

My second question is, is you were talking about moving just to the econometric model for purposes of determining the, you know, the cohorts, and if I understand it, though, it's not only moving to the econometric model, but you are using it in a fundamentally different way than PEG was, because PEG was talking about using the results of the econometric model, and basically whether the actual costs were statistically different from the projected costs, and it was only then that you might end up in an inferior group or superior group, whereas you are just talking about ranking everybody sort of from 1 to 73 or whatever, and so that -- and depending upon where you fall in that ranking, you would end up in group 1, 2, 3 4, or 5.

So under your approach, correctly, we could find that even if none of the utilities were statistically significantly different, in terms of their cost projections from their actual costs, they were all pretty close to what they should be, you would still be ranking them and putting some people in an inferior group and a superior group simply because of the way they fell out in that numerical ordering; is that correct?

MR. FENRICK: Yes, that's correct. So, yes, with the ranking you are simply saying, yes, the top 12 -- we kind of did that just to simplify. Like, no one really knows except for the, you know, the economists in the room, what does "really statistically significant" mean, and does it have any sort of meaning beyond what we kind of assign it to?

And so let's just, you know, let's just go by the rankings, number 1 through number 12. Let's just split them to 6, number 1 to 12, cohort 1, 2, 3, 4 on down.

I will say in the unit-cost econometric model we did look at what was statistically significant, and there was 11 distributors that were kind of statistically significant at the top, so -- and that aligned pretty well with the 12, so it's kind of a simplifying thing. And, you know, how much stock can you really put in statistical significance? You know, Adonis kind of walked us through how things changed.

So if you kind of just use the relative ranking of things, we thought that was just simpler to understand, more transparent, and it's still providing incentives. I don't think we want to get away from providing incentives to distributors to move up stretch-factor rankings and cohort groups. I think that's kind of a neat thing about Ontario and Ontario regulation, and, you know, we didn't really want to eliminate that, and we thought this would just simplify it.

MR. HARPER: One final question. I think this came out Dr. Yatchew's presentation, in terms of minor specifications of the model seemed to be able to, I mean, change the rankings of the utilities considerably, and I guess that would -- that issue or concern, would that apply maybe even more so to your approach, where you're not necessarily -- you don't have to be statistically significantly different. It's just a matter of where they fall in the ordering is what's going to impact them. So a minor specification in the model could -- as we saw earlier, could end up having a material difference in terms of where people fell from 1 to 73.

MR. FENRICK: It certainly is -- with any model, there will be changes as you change things, so you add a variable, change a specification. But I don't think our model would suffer from that any more than any other model would.

We haven't tested it. We haven't looked at it, but I have no reason to think that -- I would actually -- again, I haven't looked at this, so this is -- I would think our model would be less prone to that, because we are not making those economies of scale inferences that can change quite drastically depending on the specification and the way you are doing those random effects and those types of things.

But we haven't looked at it. But I have no reason to think that you our model would suffer more from that.

MR. HARPER: I wasn't suggesting it would suffer more. I was suggesting different models give different results, and that was all.

MR. FENRICK: I can't argue that.

MR. ALTOMARE: Yes. My first question is on slide 10, I believe. It's a little difficult considering the slides aren't numbered.

MR. FENRICK: Yes, they are. We just hide it.

MR. ALTOMARE: Thank you. On slide 12, then, the second bullet, you mentioned that cost theory, the model is inconsistent with cost theory. Could you elaborate on that?

MR. FENRICK: Sure. Cost theory essentially states, as input prices -- if all input prices go up by a given percentage, say 5 percent, you would expect costs to also go up 5 percent. If you have 100 employees and you have to pay them 5 percent more, the labour costs are going to go up by 5 percent. It's kind of a mathematical relationship.

And so what the current PEG table doesn't account for is OM&A and inflation could be zero, could be 100 percent. There is no change in the cost projection in there, whereas cost theory says that relationship should be what the cost share of the OM&A is, so how much OM&A expense does the utility have, in relation to the capital -- and there, it's around 40 percent or so.

And so it doesn't account for that 40 percent and the inflation that's occurred from 2002 to 2011 of that 40 percent chunk of costs. It's completely ignoring that piece. Cost theory says, no, it should actually be going up 40 percent times the growth rate in that chunk of the utility business.

So it's kind of ignoring, if you will, that chunk of cost.

MR. ALTOMARE: Okay. And the next question is on slide 31. When you looked at the unit cost econometric model and you looked at other, I suppose, drivers or business conditions, did you consider the mix of customers, like, seasonal, industrial, small commercial?

MR. FENRICK: We did try that, yes. We tried kind of percent residential, but I believe that was based on the number of customers. No, we did try -- no, sorry. It went through a few runs, but we did try percent industrial and percent general service. That did not come in statistically significant.

I think because there is a load factor variable in there already, a lot of times industrial and residential is going to be pretty correlated with load factor. If you are more industrial, you are going to be flatter and you have a higher load factor.

So we did attempt that and it didn't come in.

MR. ALTOMARE: And the other question, you have brought in the wind variable, but if you take an LDC that is large that it does see or doesn't get exposed to different types of winds, velocity, et cetera, and also the shifts depending on the Colorado highs and Colorado lows, did you take that into account?

MR. FENRICK: For instance like in Hydro One's case?

MR. ALTOMARE: Yes.

MR. FENRICK: For Hydro One, for instance, for a large distributor there, we took the average across the province.

MR. ALTOMARE: And the other question is you have kilometres of line per customer. Did you do any analysis using peak capacity per kilometre or bringing kilometres in as a normalizer as opposed to customers? The reason why I'm asking that is you also get into that quagmire or that discussion of urban versus rural, and then you get the mix.

So how did you take that into account in your assessment?

MR. FENRICK: That is accounted for in the KM of line per customer. Obviously, more rural utilities are going to have a higher value there, and you are going to have more KM of line per customer, so it is going to be a substantially larger variable.

So, for instance, in there, that coefficient number, you are going to take your variable and times that by the coefficient, and since, for instance, Hydro One is going to have a much higher variable value, you are going to have -- the model is going to say, okay, Hydro One's unit costs are going to be much higher because of that variable alone, isolated that variable, than an average distributor or a distributor that is more suburban or urban that isn't as rural.

So that variable is going to adjust for kind of that ruralness, if you will.

MR. ALTOMARE: Okay, thank you.

MS. BRICKENDEN: Are there any further questions? None on the e-mail. I have a very basic question, if I might ask it. It's on slide 27. I wondered if perhaps you might, at some point in this process, give us an estimate of what the 2012 inflation might work out to be. I'm just curious just comparing; that's all.

MR. FENRICK: We kind of ran out of time.

MS. BRICKENDEN: Yes, I understand. That's good.

MR. FENRICK: Yes.

MS. BRICKENDEN: Okay, thank you. Sorry, Larry.

DR. KAUFMANN: I have several questions. This may take 15 minutes or so, if you are okay with that.

Okay, slide 7. Slide 7, you talk about this approach to developing an external TFP trend. Is this something that you developed on your own?

MR. FENRICK: The what?

DR. KAUFMANN: Did you develop this approach on your own?

MR. FENRICK: No, I used PEG data, PEG calculations.

DR. KAUFMANN: No, I mean the approach of developing an external TFP trend by going through the industry and systematically dropping one company after another. Is that an idea that you came up with on your own? I am just curious.

MR. FENRICK: It's simply kind of an alteration from excluding two at the same time.

DR. KAUFMANN: Well, it's yes or no --

MS. BRICKENDEN: Larry, I don't see that as a clarifying question with respect to Steve's presentation.

DR. KAUFMANN: I was just curious whether there is any economic or regulatory support for this, or whether it's something -- an idea that you developed on your own.

MR. FENRICK: I would argue that typically -- say, if we weren't in Ontario and say we are trying to develop -- set a regulation plan for a US distributor. What you would do is you would look at the industry and whether you want to do a regional or you want to do the whole country, you would look at the TFP trend, but you would exclude -- what's typically done is you would exclude their own data from that FTP measurement, because you don't want the TFP measurement to impact their own parameter in their plan.

So that's typically what's done. If you are going to do it for any sort of distributor or electric utility, you would take them out of the data, figure out an external measure, and then apply that to the parameters of the plan.

So I think it's pretty well established that that would be kind of a proper method to develop an incentive regulation plan.

DR. KAUFMANN: Okay. So on slides 8 or 9, you have a number of different TFP measures, and are you saying that every one of these measures is external?

MR. FENRICK: External to each one of the distributors, yes.

DR. KAUFMANN: Okay. Let's see. Slide 32, you talked about a cost theory and having that cost model being consistent with cost theory. And you have a unit cost model here on this page. Do you believe that this is a well-specified model that is consistent with cost theory?

MR. FENRICK: Define "consistent with cost theory".

DR. KAUFMANN: Well, there are cost models in the literature and there are variables that have to appear in cost models. Does this model include all those variables?

MR. FENRICK: It includes a number of variables. I am not sure what variables you are alluding to.

DR. KAUFMANN: Does it include input prices?

MR. FENRICK: Yes, that is actually in the cost. It is kind of cost divided by input prices. So it's kind of the real cost.

DR. KAUFMANN: So you have here cost divided by N, but it's really cost divided by N plus an input price index?

MR. FENRICK: It's cost divided by the input price index divided by N. So it's kind of real cost divided by N.

DR. KAUFMANN: It is?

MR. FENRICK: Yes.

DR. KAUFMANN: Okay. On slides 36 and 37, you talk about the benchmarks that you create, and you are saying that this leads to better inferences or more accurate measures of efficiency. Do these measures reflect -- what you have here on these slides, do they reflect efficiency or some combination of efficiency and scale economies?

MR. FENRICK: I mean, I would argue that utilities that find scale economies, those are efficiencies. They are lowering cost. They are lowering their cost structure by either growing larger or merging, and those that they can pass on to customers. So, I mean, I would argue economies of scale and being able to identify those and have managers manage towards finding those efficiencies, you know, is cost efficiency.

DR. KAUFMANN: So you don't think economies of scale and efficiencies are distinct concepts?

MR. FENRICK: I mean, they are certainly different subsets of the same concept, is lowering cost for -- of the operations of the industry.

DR. KAUFMANN: Okay. Slide 13. In slide 13 you talk about PEG's prior practices on -- with respect to TFP decomposition and TPP projection, and you reference -- I guess this isn't on this slide, but on another slide you reference the 2009 report. On this slide you say that our projection of TFP using an econometric model is incorrect because we omit one of the input prices, so we have two input prices in the data set. We have capital and OM&A. But you make reference to other PEG work that you say is correct.

And is it your understanding that those PEG models also include all the input prices that are reflected in those studies, those projections?

MR. FENRICK: So if I could rephrase, so you are essentially saying the PEG 2007 methodology, does that include the different input prices? Is that what you are asking?

DR. KAUFMANN: Yes, there are three input prices there. Are all three of those input prices reflected in the TFP projection?

MR. FENRICK: Essentially, yes. In the 2007 methodology they are, because you are not -- in that methodology there is no cost projection going on. It's actually just a TFP projection. And so you are looking at, what's the technology trying to say, which is kind of that negative 1.2 percent, then what's the economies of scale that the model would expect. Then you add those two up to get the TFP projection.

So, you know, it's not really intended to have OM&A, because you are not really projecting costs in any way.

DR. KAUFMANN: But I was talking about the 2009 paper, which you also referenced. Does that include input prices?

MR. FENRICK: In the -- I would have to double-check that.

DR. KAUFMANN: Well, okay. I will just leave that as something to check, and whether or not that includes two or all three of those input prices. And again, that is the same methodology that was used in 2007.

And I would also like to go to slide 54, which you didn't go through. But this is central to your claim that we somehow got the calculation wrong. Maybe this is -- did you take this out? There was a -- I had an earlier version which had "hide the calculators". Is that still here? Okay. 55. Okay.

Now, here is where you say that we are getting the calculation wrong. Let's start with the second box. You have got the dependent variables cost divided by the price of OM&A, correct?

MR. FENRICK: Correct.

DR. KAUFMANN: And we have a number of different variables on the right-hand side. And the coefficients that are estimated on the right-hand side obviously depend on the value of the left-hand-side variable, correct?

MR. FENRICK: Say that again?

DR. KAUFMANN: We are estimating coefficients, and the coefficients that we estimate depend on the value of what's on the left-hand side, the cost measure, and that's a deflated cost measure, and if that changed, the coefficients on the right-hand side would also change; is that correct?

MR. FENRICK: No. If I understand your econometric approach correctly, you are using a system, SUR approach, so a system of regressions, in which case that capital input price is is actually the capital cost share. It's basically given. So .59 is the capital cost share in there.

So it's not really given by the left-hand side. It's given by the data that's -- 59 percent is the capital cost share due to the system of equations that you have. I know that's technical, but...

DR. KAUFMANN: No, this a more general question. It's just, if you change what's on the left-hand side of a regression and you are estimating coefficients and you have a number of variables explaining that, does that affect the coefficients that are estimated throughout the regression? It's not just the cost of capital variable.

MR. FENRICK: So the .59 would not change, right?

DR. KAUFMANN: I am not asking about that. I am asking about all the coefficients.

MR. FENRICK: Yes.

DR. KAUFMANN: Yes, so they would. So when you said that, for example, we have OM&A growing by about 2.3 percent, and it doesn't control for the fact that if it was growing by 10 percent then that wouldn't be reflected in our model, but if it was growing by 10 percent, then this - the left-hand side would change, which would mean everything else in the model would change; is that correct?

MR. FENRICK: Except where OM&A shows up.

DR. KAUFMANN: Well, let's deal with that. So now we get down to -- but you are agreeing it would change the coefficients of the model.

MR. FENRICK: It is going to change some coefficients, but not where the input price shows up. So it's going to change the coefficient on your number of customers, for instance, or volumes, but it's -- you know, the cost model, as I understand it, is constrained so that the elasticities of the input prices add up to 1, because it wants to conform to cost theory, which your cost model does. So all those have to add up to 1, so it is constrained, those coefficients are constrained, to add up to 1.

DR. KAUFMANN: Okay. Let's go to the fifth square here. You have the change in cost multiplied by the change in the capital price, plus this inferred change in the OM&A input price, which is something that you inferred, just by looking at the impact of the capital price, and then you have "stuff".

The question is -- and the reason we have this is that the capital price was divided by the OM&A price in this model. The question to you is, is the "stuff" that you are now talking about in this equation, does that stuff also include the capital price divided by the OM&A price? Is that anywhere in these models -- in any of these terms that you didn't consider?

MR. FENRICK: No, not at the mean.

DR. KAUFMANN: Well, it is. There are -- if you go through and you go through the math, what you will find is if you add up all those coefficients everywhere where these terms appear, what you get is 1. -- you have got minus the OM&A price on the left-hand side. If you add up all those coefficients on the right-hand side, you get 1.022.

So in other words. this .41 you get, the only reason - and remember, this is the math that you are using to justify your claim that there is an error - the only reason this is happening is because you stopped at one variable and you didn't essentially complete the math.

MR. FENRICK: Can I comment now?

DR. KAUFMANN: Yes.

MR. FENRICK: Where do those show up on table 19, all those other variables you are saying?

DR. KAUFMANN: They show up in table 12 --

MR. FENRICK: Right. Table 12. Where do they show up on table 19?

DR. KAUFMANN: They don't have to. This is a variable -- this is what you are using. It's just a question to you whether or not there are variables -- this is the algebra that you are using to infer the fact that we made an error, and you are using the coefficients from table 12, so the question is whether there are other coefficients in table 12 in this "stuff" term which include the price of labour divided by the price of OM&A.

MR. FENRICK: You are aware that your model's mean-scaled, right?

DR. KAUFMANN: Yes.

MR. FENRICK: And so at the mean, all those quadratics, interaction terms, are going to fall out, because the natural log of 1 equals zero.

DR. KAUFMANN: Well, now, that's just not true.

MR. FENRICK: It actually is.

DR. KAUFMANN: You have to follow -- okay. Well, let's debate this tomorrow if you like, but the point is that there are other terms, there are other terms here, that are reflected in this that are not reflected in this calculation.

MR. FENRICK: And all I would say to that is -- well, then you have made a different error, because those then should show up in table 19.

MS. BRICKENDEN: Maybe it would be helpful if --

DR. KAUFMANN: Let's talk about this tomorrow, but --

MS. BRICKENDEN: Well, yeah, or at lunch maybe the three of us can sit down and try to understand what the issue is here, because I don't -- I think this happened last time. I think there might be three people, maybe four -- I'm looking at Jay -- three and a half that might understand the technical details here.

MS. CONBOY: You are giving him too much credit here, Lisa.

MR. SHEPHERD: Much too much.

DR. KAUFMANN: I'm just trying to clarify. I really am just trying to clarify the calculations that appear in the table, so that's fine for now.

MS. BRICKENDEN: I think, though -- yeah, I'm not -- I take a light leap that I am not the only one that's not following all of this, so perhaps over lunch, as you suggest, you could go through it and explain to us what it is that perhaps the rest of us are missing, and if not this afternoon, then tomorrow, but I think Dwayne had a question.

MR. QUINN: Thank you. I just -- I don't want to hold us up for lunch, but maybe I'm going to lob you one like you did to your three-year-old, because I struggle with this in the PEG report, in terms of the impact of age, and you have two age variables. One is age, and then age squared. But the coefficients -- sorry, they were on the screen before -- the coefficients seemed to go in different directions, negative and positive, you know, to a large extent.

Can you just help us at a very high level what it is you believe this is telling us?

MR. FENRICK: Sure. It's actually a really interesting finding. So essentially it's saying age, kind of first age term. You know, as distributors get older they are going to save on costs, right, so you are not -- your assets are depreciating. You are going to save on costs as you get older and older, simply because you are not putting new capital in and you are kind of taking advantage of a system growing older.

Where the age squared comes in is there is a certain turning point there where, if you get old enough -- quote-unquote, old enough -- at a certain age that starts turning around, and there is going to be different cost pressures, higher maintenance. You are going to have to start replacing things, where you are actually going to be facing higher cost pressures at some point along that spectrum, of the age spectrum.

So if you a brand new utility, say, greenfield, you just built all new assets, you are one year old, well, you are going to benefit from going from one year old to two year old. You shouldn't be replacing your whole system after one year. There is going to be benefits there from one year to two years, and two to three years, three to four on down.

But there is certain point where that age starts catching up to you and is going to start -- that old age is actually going to start increasing the cost pressure on you. So that's kind of the quadratic term. Does that help?

MR. QUINN: That is very helpful. I appreciate the understanding. Just one more point of clarification, if I may, then. I see the asterisk here says, "all variables are statistically significant". So they are significant each to themselves, and yet when, as you see, as you have just described, age tends to change in terms of its effect, but you still are able to get a statistical significance for either of them on their own. When you put them both together, is it statistically significant?

MR. FENRICK: So, basically, if you went to one variable?

MR. QUINN: Yes, one that tried to capture the two effects, or an equation that captured the two effects because you have got a squared equation.

MR. FENRICK: I believe if you do one variable -- this isn't definitive, because I would have to go back and check what actually happens, but I believe it would go statistically insignificant, because you are not separating out those two impacts.

So if you just have age in there, because some distributors in the province are so old -- you know, they are old, so they are past that turning point already. So their costs are going up. There are other ones that are younger.

So that kind of gets all meshed up if you just go to one variable, but if you separate the two impacts, then you get statistically significant. I probably wasn't as clear as the last answer but...

MR. QUINN: No, and I wasn't as clear in my question, so I am going to ponder that and see if I can be more specific in my question. Thank you.

MS. BRICKENDEN: Thank you, Dwayne. Are there any further questions, anything that's come in through e-mail?

Well, thank you, Steve. I think at this point it would be good time to break for lunch for an hour. Our clock isn't working, so it's about five to 1:00 now. Shall we reconvene at 2 o'clock?

--- Luncheon recess taken at 12:55 p.m.

--- On resuming at 2:02 p.m.

MS. BRICKENDEN: Good afternoon, everyone. We are back on air. This afternoon Larry Kaufmann will be presenting, and if you recall, those of you who participated in the Q&A on May 16th, a number of questions were raised at that time, and we suggested they may more appropriately be addressed at this event.

So those questions, I have made note of some of them here, and I trust, those of you who did raise certain questions, please feel free to ask today additional clarifying questions to Dr. Kaufmann.

Are there any questions before we proceed? Then I pass the mic over to Larry.

Presentation by Dr. Kaufmann:

DR. KAUFMANN: Okay. Thank you, Lisa.

I have been through this a couple times before. I have talked about the results. I have answered questions. So my plan for today is to go through this fairly rapidly to leave as much time as possible for questions.

So I am mostly going to focus on the impact of the data changes on the results, present the updated results, talk very briefly about what we did. Again, I have been through this a couple times before. I think most people in the room have heard the presentation. So rather than repeat what's been heard, again, I am just going to focus on the update and the changes.

But before I get there, I would like to say something very briefly about the overview and the big picture, because I think this is important, and this was important to me as I worked on this and as I the developed the recommendations, and I was keeping the big picture in mind.

And the big picture is the renewed regulatory framework. The Board has established a new regulatory framework for electricity distribution. It has a number of different elements, and within rate-making there are three rate-making options that have been established under the RRF, and one is what we are spending most of our time talking about, which is the fourth generation incentive regulation plan.

And in the RRF report the Board said that fourth generation incentive regulation should be suitable for most distributors, and that includes -- and that pertains to companies that have some incremental capital expenditures expected during the term of fourth generation IR.

There is also two other options. One is a custom incentive rate-setting option, and that's designed to be suitable for distributors with large or highly variable capital requirements.

And then the annual incentive rate-setting option is suitable for distributors with very limited incremental capital needs. And the Board described this a bit in terms of the framework and the fact that it established flexibility, it created options for distributors, mostly to accommodate differences in lumpy investments, and I think that's important to keep in mind.

There are a number of different elements of the RRF, and today we are focused on the empirical research that's primarily an element and an input into the fourth generation incentive regulation option, which, again, is suitable -- is designed to be suitable for most distributors in the province.

So when I put together the recommendations for this case, the recommendations for inflation, productivity, and stretch factors, here is what guided my work. One, I obviously wanted these recommendations to use the best possible empirical research that we could develop. I also wanted it to be consistent with the principles for effective incentive regulation. I think both of those should be relatively non-controversial. And I wanted it to be compatible with Board policy direction, as set out in the RRF report. And part of that direction was that fourth generation IR would be appropriate for most distributors in Ontario.

So I think, again, it's important to keep this in mind, to keep in mind that this is a flexible framework, it allows for diversity within the regulatory options, and we should be aware of that when we think about this particular option and what's appropriate for most distributors in the province.

So we have talked a lot about the data. I don't think I am going to go into that much more. There was a lot of data -- effort involved in this project. We pulled together data from the past, from the relatively distant past, and from a lot of different sources, including a supplemental data request.

And part of what we did is we developed separate cost measures for the TFP and benchmarking analyses, and this was important because the TFP cost measure is designed to apply to the costs that are going to be subject to the fourth-gen IR mechanism, and some of those costs could potentially lead to non-comparabilities in cost because of -- particularly for differences in high-voltage transformation.

Some -- a relatively small number of distributors in the province perform high-voltage transformation, and if there are no controls for that in the benchmarking, then that can lead to inaccurate inferences on how relatively efficient one distributor is.

So the cost measure that we developed for TFP was designed to be one that was focused on the set of costs that are going to be subject to the rate adjustment mechanism under fourth generation IR, but the benchmarking cost measure was designed to control for differences in companies so that we could make the best apples-to-apples inferences on efficiency that we could.

So we have these three adjustments, high-voltage transformation, that was taken out of the TFP cost measure for benchmarking. We added in contributions in aid of construction to the capital stock, and we added in the low-voltage charges.

And here is a slide that briefly summarizes those, the differences in those measures.

So three sets of recommendations. One is on the inflation factor. We are recommending a three factor inflation factor with separate indices for capital labour and non-labour OM&A input prices. The capital input price is a relatively simple capital service price that includes rate of return, depreciation, which is constant, assumed to be constant for all firms in the industry and over the entire sample period, and the EUCPI, which is an asset price index, a construction cost index.

The labour price index was the average weekly earnings for workers in Ontario, and the non-labour price index was the GDP-IPI for Canada. And because volatility is an issue -- and the Board was aware that going to an industry-specific price index, which was part of their guidance for this consultation -- they were aware that that would likely be a more volatile index than the GDPIPI, which is being used right now in third generation.

So we wanted to be -- to examine the volatility issue and come up with some way to mitigate that so that this doesn't lead to excessive volatility while this inflation index is in effect, and our recommendation is pretty straightforward and pretty simple. It's just a three-year moving average of the inflation that's calculated annually by this three factor inflation factor.

And here is a table that most of you have seen. This presents changes, annual growth in the recommended inflation factor, and the three-year moving average, how the three-year moving average of this inflation factor -- what values would have been produced by it if it would have been in effect from 2002 through 2011, and then we compare that with the actual inflation factors that were used in 2010/2011.

And the biggest change, obviously, is what's happening in 2012, which was something we added. Our report looked at 2002 through 2011, but since we issued the reports the 2012 data became available. We calculated that, the inflation that would have been generated by this IPI, and it shows that there would have been a significant negative inflation number for the 2012 year.

And when you roll that in for the three-year moving average, that would bring the inflation factor down for this year.

Productivity factor, we present two types of analyses in our report, and I think it's really important to remember that in its guidance for this consultation, the Board said in its RRF report that an index-based measure of productivity will be used for the basis for the productivity factor.

That's a statement in the report. Given that, we put by far the most emphasis on the index-based measure of productivity growth in our report and throughout the working group meetings and throughout this whole process. So that was always going to be the basis for a recommendation.

But there was some concern about the sample period, because it was relatively short. There were a lot of things that happened during it. There was a very severe recession. Companies went off the rate freeze that they had been on for years. A lot of events took place, and there was potentially some concern that an index-based measure, for whatever reason, may not be -- it may not be capturing everything that happened in the sample period.

So just as a sanity check -- and that was a term that was used many times during the working group, the working group process. Just as a sanity check, we decided to do an econometric back-cast to supplement the index-based estimate of TFP, but, again, the index-based estimate is our measure, and the econometrics estimate tended to confirm it. So in that sense, it was a piece of confirming evidence.

And in both of these estimates, we removed Toronto Hydro and Hydro One from the definition of the industry, and we ran formal statistical tests which showed that if Toronto Hydro and Hydro One are in the sample, then there will be a statistically significant difference finance on the industry TFP trend in at least two ways. One is the impact on the cost elasticities.

Our output index a weighted average of the growth in customers and capacity and deliveries, kilowatt-hour deliveries, and the weights are based on the relative -- based on, basically, the cost elasticities that are associated with each of those outputs in the cost function, but those cost elasticities are weighted so that they add up to one.

So what we found was that -- so there is a direct link between that element of the econometric work and the TFP estimate. If the cost elasticities change, then the TFP estimate will probably change, because that puts different weights on customers, volumes and capacity and also on the industry cost trend.

We have talked about that a bit this morning and potentially the implications for that, and what we found was that -- we did formal tests and found that when they are in, they will be -- they will impact the cost elasticities and they will impact the industry TFP trend. So that's formal statistical evidence to show that when these two companies are in, they are -- they are having a statistically significant and material impact on TFP.

But I think common sense and just understanding of the industry would also support the idea that when you have two companies that are about 40 percent of the industry and they have very different TFP trends than the other 60 percent, then when you just add them -- when you take an average for the whole industry that includes them, those two companies, then that will have a significant impact on the TFP estimate. And that's what we found.

And that's important, because in incentive regulation the TFP trend that's used should not be materially impacted by one or two utilities in the industry, and the reason is you don't want one or two companies -- you don't want the experience of one or two companies to be setting essentially the TFP target for the rest of the industry.

And, remember, fourth generation incentive regulation is supposed to be suitable for most distributors in the industry. So if we have one or two distributors that are significantly impacting the TFP trend and that would change the TFP trend that applies to the other 71 by something like 1 percent, well, to me that's strong evidence that that is a TFP trend that is not external to the performance of the dominant companies in the industry, dominant in terms of size.

So our original TFP estimate, the index-based estimate, was zero. There were some problems with the low voltage data, and I think what happened there was we had a fairly significant change in our data set in about mid-March and we had to kind of collate -- because of that, we had to re-collate all the data series in our data set, and we obviously picked the wrong low voltage data when re-established the data set.

So my apologies for that, but we have it fixed. And when we do that, what we find is, when we correct that data, that the TFP growth estimate is now changed from zero to -- or at least my recommendation is changed from zero to 0.1 percent. And the reason for that is -- I will get to that in just a second. The reason is because of what's happening on output.

Remember, the cost elasticities that are measured from the econometric model factor directly into the estimated growth in output, because output quantity growth is a weighted average of the growth of these three specific outputs, and those weights depend on the cost elasticities.

And the low voltage data does not enter directly into the cost data we use for TFP, but it does enter into the benchmarking data; and that, in turn, will impact the econometric results and the unit cost benchmarking results.

So what we found was when we changed the data, we re-ran the model, the weight on customer numbers increased fairly significantly. Now I believe the weight is now 0.44. That's the coefficient. I can't recall, but I think it gets about a 50 percent weight right now.

Peak demand is still the second biggest driver. Deliveries are much lower. The weight on deliveries is much lower than it was before, and, in fact, that's because the coefficient on deliveries is much lower. And, in fact, the kilowatt-hour variable in the model is now not significant at the 5 percent level, but it is significant at the 10 percent level.

So there is much less weight on -- when we changed the data, when we got the correct data in there, there is much less weight on kilowatt-hours, and in fact kilowatt-hours is less statistically significant than it was.

So the impact of all that is is now there is greater weight on customer growth. As you can see, here customers are growing more rapidly than peak or kilowatt-hours, so when you put more weight on that, that raises the overall growth on output.

The impact on output is it raises it by 15 basis points. So the previous growth rate was 1.21 percent in our May report, and that's now 1.36 percent. So when you make that change, nothing else changes about the TFP estimate, but because output growth went up by 15 basis point, TFP goes up by 15 basis points. So the indexed-based estimate for TFP is now 0.1 percent instead of what it was estimated before, negative 0.05.

Again, capital didn't change, and I have talked about that. OM&A didn't change, and the TFP changed only with respect to the output quantity index. And, again, that flowed directly to the TFP growth rate. So that's the productivity factor.

The total cost benchmarking recommendations, as I think most of you know, we developed two models, an econometric and a unit cost peer group model. The econometric model, I think there is general -- at least general understanding of what econometric models do.

And what we did is we estimated the main drivers of electricity distribution costs. We used that model to predict the cost of each distributor, and then we constructed confidence intervals around that prediction and looked at the actual cost relative to predicted costs, plus or minus the confidence interval.

If you are outside of the interval, then you are either statistically superior or interior, depending on whether your costs were above or below the interval.

And the unit-cost peer group model, that is looking -- that's constructed unit costs for every company and then comparing each company to the mean unit cost for the companies that were deemed to be peers of that distributor.

And we determined those peers based on similarities and cost drivers in a process that I discussed in detail on May 16th and also discuss in the May 3rd report.

So there have been some changes in the econometric model, and these would change, you would expect them to change, because the low-voltage data changed. So whenever you change what's on the left-hand side of an econometric model, that will have implications for the variables on the right-hand side, and that's what we found. And it's also changing the fundamental cost for those distributors. So when you look at benchmark costs minus actual cost, that also changes.

And what we found is we now have 14 distributors who are significantly superior cost performers at a 90 percent confidence level. Nine of them are significantly superior at 95 percent confidence. And that's an increase from what we had before. We are finding more companies are significantly superior, which makes sense to me because, if the costs data are wrong, and they were, then in a sense you are loading too many costs into some of these companies, and obviously it's going to be more difficult for those companies to be identified as superior if their cost measures is too high.

And there are 18 distributors that were significantly inferior cost performers at 90 percent level, nine of those at the 95 percent level. That's very similar to what we found before.

And here is a table presenting those results. I believe there are one or two typos. Professor Yatchew was asking me about this table. And there are no changes in the -- obviously, we are giving anonymous IDs to companies rather than giving their names, and there are no differences between the anonymous IDs that we have here and what we have before, but one or two typos kind of slipped through in the rush to get this done last week, so I apologize for that. We can clean this up.

So for example, there's distributor number 75. There is no distributor 75 in our sample. So that is the econometric results.

The peer group, the peer group unit cost benchmarking, again, we have talked about this. We wanted to select peer groups that were based on similarity in cost drivers. We wanted that selection process to be as transparent as we could, and we also wanted the peer groups to be above a critical size, which was somewhat undefined, but it turned out to be -- ten turned out to be a number that resulted kind of naturally from looking at the data and how the companies got split into different buckets based on the econometric work.

I should also say that I talked about the econometric model and the fact that kilowatt-hours were less significant in the model. We had several other variables in the model, including kilometres, kilometres of the line. The coefficient of kilometres of the line change, now it is a much bigger cost driver than it was before. And kilometres of line is an output, not in the output index, because we didn't have good time-series data on it, but it is an output in the unit cost model.

So that gets more weight in the unit cost analyses. But a couple of the variables turned out to be less significant or insignificant, and those were undergrounding and area.

So we haven't changed the peer groups yet. As I said on May 16th, I have always been open to the idea of refining the peer groups, but as of right now we haven't made any change in the peer groups to reflect the fact that these variables are no longer statistically significant.

I don't know whether, if we perform the same analysis but excluded those variables, whether there would be any changes. I don't know. I don't think they would be major, though.

And Table 23 shows the peer groups that were actually created. Table 24 -- and you may have noticed one difference between these slides and what was presented on May 16th. On May 16th we suppressed company names on this table as well. But one of the things that we were asked to do after that presentation was what was called a mapping of all the steps that went into this calculation.

So in other words, what were the total cost constructions in each of these years, 2009, 2010, 2011? Show how those costs were added in each year, show how the unit costs -- how the comprehensive output that's the denominator of the unit costs, show how that was constructed, show what the unit cost average was for each year, and then what the benchmark -- how that compares to the benchmark.

Well, the reason we didn't do that last time was because we wanted to suppress the names, and we were asked to suppress the names. And if you do all that work and you go directly back to the data, well, it's -- you know, there's no point in -- you can follow the calculations through and determine which company is which in these tables.

So given the fact that we were asked to do that and to make that calculation more transparent, we just went ahead and presented these names in table 24.

Table 25 presents the unit cost evaluations. These are just a ranking of how companies' unit cost, the average for 2009 through 2011 compares to the benchmark for 2009 -- 2009 through 2011, the mean, the mean for the peer group, and we computed those and just ranked those from 1 to 73, where bigger negative differences are evidence of more efficient performance.

And then the stretch-factor recommendations, I recommended five efficiency cohorts, with the stretch-factor values ranging from zero to 0.6, and the cohorts were based -- as in third generation, they were based on how companies did on both of the -- both the econometric and the unit-cost benchmarking models, and here are the criteria for being in one cohort versus another, and the stretch factors that are associated with each.

Compared to third generation, the mean stretch factor was reduced from .4 to .3. The range was increased slightly. In third generation it went from .2 to .6. Now it goes from zero to .6.

And the reason for having five cohorts rather than three, which we have right now, is to make it easier for companies to migrate from one cohort to the other based on their own behaviour and ability to reduce costs.

And here are the -- based on these two tests, here is how the cohorts would shake out. Eight companies in cohort 1, four in cohort 2, four in cohort 4, and 13 in cohort 5.

So not that there is any reason that this necessarily should be normally distributed, although that was a criteria that was considered important in third generation. We wanted the distribution of efficiencies to have kind of a bell curve. This is not exactly a bell curve, because it's a little bit more weighted towards the cohort 5 group, but it's in the neighbourhood.

So just to conclude, we have presented recommendations for the inflation factor, productivity factor, and stretch factor, which we believe are consistent with the Board's direction and the RRF report, and that includes developing parameters for fourth generation that are appropriate for most distributors in the province.

We have an Ontario-specific inflation factor. We believe that's possible. Volatility can be mitigated, but I think one thing we are seeing is that volatility in an industry-specific inflation factor is never going to go away.

This is inherently a more specific metric than the GDPIPI, so you can mitigate that in different ways, but it will be more volatile.

The low value of the productivity factor mostly reflects slow output quantity growth. We have talked about that. But the benchmarking suggests that there still are a number of distributors who can achieve significant efficiency gains through cost cutting, and the framework for fourth generation IR should strengthen companies' incentives to pursue those incremental efficiency gains.

So I think I did that in a half-hour, and now I can take questions.

Q&A Session

MS. BRICKENDEN: Judy?

MS. KWIK: I will start you off on an easy one. I just want to know where I can find the calculations and the data for the input price index calculations for the annual growth. You provide all those worksheets on -- where can I go to find this?

DR. KAUFMANN: Tables 1 through 5 present the details of all that, and it shows -- we have those as a spreadsheet. So that was done in an Excel spreadsheet, and so you can look directly at those tables and see those calculations.

MS. KWIK: Okay.

MS. BRICKENDEN: Carm, and then Bill.

MR. ALTOMARE: Slide number 30, cohort 5, you have distributor 74 and 75.

DR. KAUFMANN: Yes.

MR. ALTOMARE: So those are excluded or is that, like, a trick?

DR. KAUFMANN: I don't know how those numbers got in there. I can't explain that. I will look into that.

MS. BRICKENDEN: Phil?

MR. HARPER: Actually, I just wanted to get sort of a big picture of --

MS. BRICKENDEN: Sorry, Bill, I think Phil --

MR. HARPER: Oh, Phil. I thought you said Bill.

MS. BRICKENDEN: Maybe the microphone isn't on yet. Come up to the...

MS. MARLEY: Sorry, I wanted to talk a bit about low voltage charges. When I looked at -- it's Phil Marley from Midland. When I looked at our costs on the revised report - and thanks very much for doing that - what is included are the LVDS, monthly service charges and the common ST charges. And I am wondering, why are the common ST charges included and the monthly service charges?

DR. KAUFMANN: That is what we agreed during the working group. That was the definition of what should be included and what we included in our cost benchmarking measure.

MS. BRICKENDEN: I think in fairness to the working group, that is what is documented in the material that we circulated after the meeting, and that is what we gave Larry. So we were given a short list of what to include and what we would not include, and the common ST was on that list. So I would throw the question back out to the group. If you do not think that is appropriate, then we need to understand that.

MR. TUCCI: I'm Morris Tucci, EDA. What I recall from that meeting, just prior to the meeting that we had on the scorecard, the PBR working group, we spent a lot of time talking about this, and I guess it's a hard concept to get across.

And it was a discussion I had with Bill Harper, and we finally got some understanding that ST common or sub-transmission costs that are essentially a layer of transmission costs - sub-transmission costs, we call them - hey are lines that are below 50 kW, and they are used to -- in place of transmission lines to connect supply -- connect load, I should say. And they are embedded within Hydro One's territory and they run through.

And we had a long discussion about: Is it appropriate that -- to try to create a level playing field, should we include these costs of lines that are lower voltage that are used to connect distributors? Are they in any way comparable to what a distributor that's connected at a higher voltage would be using within its own territory?

What it came down to is an understanding that within a utility territory, yes, it has these kinds of lines, also, but they are not, and never would be, for a typical utility as long as these lines. These lines are very long lines that essentially work like another layer of transmission to connect certain utilities, a large number of utilities. And it's not an insignificant cost.

Whether it's in or not, does it have a bearing on some utilities? In I think Midland's case, it's something like in the range of 15 percent of their total costs is just the sub-transmission cost.

And so it has a bearing on the benchmarking analysis, whether it's in or not, and we did discuss it. And it's very controversial whether -- what portion of that cost should be in, but the vast majority of that cost should not be in. That's the way I see it, and I think that was the understanding of the working group.

It's not like everybody in the working group completely got their head around this, unfortunately, and it doesn't get translated easily. And maybe you need diagrams to explain it, but Bill worked in this area at Ontario Hydro for a long time and I think he was agreeing with me. Bill?

MR. HARPER: No, I think Morris has got the genesis of it. I think the other issue is the piece that you didn't mention, Larry, that I think would be more obvious to include, would be there is another piece, which is LV specific, which is the lines that are owned by the host distributor. They are actually operating inside the embedded distributor's territory. Those, in my mind, are functioning much more like the lines that a distributor would actually own themselves, because they are inside the distributor's territory.

So maybe there was a mixup in terms of what should be in and what should be out, because it seemed to me that those ones should clearly be in, because they are inside the -- just somebody else happens to own them, but they are moving power around within the service area of the embedded distributor.

The other ones are outside the distributor's boundary. I guess it depends on what you view as the function of the distributor. And if it's supposed to be taking delivery at its boundary at a certain deemed voltage and stepping it down, then you would exclude those, but include the DS stations like you have.

Again, I think this is something I am not too sure whether the group as a whole actually came to consensus on this. I think there were various opinions expressed around the table at the time, and I had an opinion and other people had different opinions. I don't think we ever took a vote or came to any consensus, to be quite honest with you.

DR. KAUFMANN: One thing I can say, I do remember the discussion about the sub-transmission comment, because we talked quite a bit about whether there is a business condition variable that we could use to control for that. And since that was a part of the discussion, that kind of lends support to the idea that we thought it would be in the cost side of the equation, because we did talk about that.

So, I mean, my recollection is that it should be in there. Bill, are you saying that there other charges that we excluded that are LV-specific that are a separate part of that file?

MR. HARPER: I was just going from the costs that you said that you had included, and there is another -- Hydro One being the primary host distributor, it owns lines that are outside of the embedded distributor's territory, that it delivers it to the boundary of the distributor, but also owns lines that are inside the distributor's boundary.

Sometimes the line is running through to somebody else on the other side, to be quite honest with you, and those are called -- I mean, they are LV-specific lines, because they are specific to the LV. I didn't hear you mention those, and that is why it seemed to me, since you didn't mention them, I took the presumption you had excluded them. And I didn't think they should be excluded.

DR. KAUFMANN: Okay. Well, you know, there is no -- there is a lot of -- this is a difficult issue. There is a lot of institutional difference among companies, and these costs don't really get cut up as cleanly as we might think. There is no bright line, I hate to use that pun, but in terms of deciding what should be in or out of the cost measure.

So we could run -- we are going to prepare a supplemental report. We could run some sensitivity tests to use one or two different definitions of low voltage costs and see how things change, in general, and for specific companies.

MS. MARLEY: Just on that note, when I looked at the revised data, I was looking at the common ST charges for various distributors, where they were on your OM&A cost table. I thought, well -- I am trying to figure out, well, why wouldn't this distributor have costs, and why do we have such a large cost?

And some of the costs, when I looked at the table dump from Hydro One, some distributors have the common ST costs, but it didn't appear on the OM&A. So I am wondering if maybe you could just have a re-look at that, as well.

MS. BRICKENDEN: Sorry, I don't know if I understand the question.

MS. MARLEY: The charge that is included for LV includes a common ST charge; right? When I looked at the Hydro One data, some distributors have common ST charges, but it doesn't appear in their OM&A similar to what Midland's is.

DR. KAUFMANN: So you are saying that --

MS. BRICKENDEN: On Larry's table.

MS. SPOEL: Yes.

DR. KAUFMANN: So you are saying that the ST common was not calculated in a comparable way across all distributors?

MS. SPOEL: Yes.

DR. KAUFMANN: Okay. I will look into that.

MS. BRICKENDEN: I think it would be helpful to -- maybe we can circle back with the working group and see if we can get agreement on LV in and out, and I am a little concerned if I hear that Larry might do sensitivity analysis, tweaking this for this utility and tweaking that for another utility. I would like one definition. And perhaps we can circle back with Hydro One if we need further clarification on the data they provided.

Carm, you had a question, or did you forget your question?

MR. ALTOMARE: Bill.

MS. BRICKENDEN: Bill did. All right.

MR. HARPER: Actually, Larry, on the updated data, I just wanted to -- I had a little chart in my mind which has got four boxes in it, because you talked about doing two tests, the index test and the econometric test, with all the distributors, and with all the distributors except Hydro One and Toronto Hydro, and that last box, I understand now, has 0. -- is the 0.1 value -- excuse me, no, the index test, excluding Hydro One and Toronto Hydro, that's the 0.1 that you got in the presentation here.

DR. KAUFMANN: The 0.1 is a TFP trend for the industry, excluding Toronto Hydro and Hydro One.

MR. HARPER: Right, right, and I guess I was just trying to fill in, if you could, because I think it was in the main report, what the other three boxes are. If you did your TFP trend, you know, output minus input, for all the distributors, including Hydro One and Toronto, what would it be, as opposed to the 0.1 in the analysis?

DR. KAUFMANN: Now it's negative 1.1. It was negative 1.24.

MR. HARPER: And I guess -- and you said -- remember you said you used the econometric analysis as your, I guess check, sanity check, if I can put it that way, and the with and without numbers on the econometric analysis, what are they now?

DR. KAUFMANN: I believe the econometric -- I would have to look at that. I believe that is negative .08, so there is more of a discrepancy.

MR. HARPER: Okay. And my second question was -- and it goes back to the two presentations that were made this morning, and to some extent I got the impression that those two consultants, when they looked at your econometric results, for purposes of coming up with the. you know, using of the TFP trend, looked at the coefficient you had on the trend variable, and the coefficient on the trend variable there was 1.1 or 1.2. That was what they were assuming was coming out of -- was the TFP trend coming out of the econometric analysis, and I don't think you used that same approach to come up with a TFP trend based on the econometric analysis, and I was wondering if you could say yes or no to that, and if the answer is no, why using -- why in your view simply using the coefficient on the trend variable isn't the right way to do it.

DR. KAUFMANN: I am happy to do that. I don't know if that's a policy issue or -- for tomorrow. I am happy to do it.

MR. HARPER: Well, I mean, you are the one that's sort of -- was using your analysis to come up with a comment on what you think, using -- resulting from the analysis, personally I don't see as a policy trend. You've got a -- you've got analysis and what -- how you think that analysis informs what the TFP should be.

DR. KAUFMANN: Okay. Well, we didn't use it. We did not use the coefficient on the trend as an estimate of TFP. And in general, the PEG approach and my approach has always been that indexing is approached, is -- it should always be used, unless one of three factors applies, and these are the only cases when PEG has ever used a TFP decomposition approach.

And one is if -- is if you don't have enough companies in the sample to create a TFP trend, and that was the case in -- for the gas distributors in Ontario. There are only two companies, and if we estimated TFP for those two companies, well, you know, I mean, obviously those two companies are going to dominate.

There is no way to create an external TFP trend with just two companies, so what we did in that case was we actually looked to the US, developed some econometric work, and projected that into Ontario. So it's an out-of-sample projection.

And the same -- the other two reasons are, if the future is different from the past, so, you know, you can get an econometric approach, and you can generate some coefficients that tells you in, you know, some sense of what the fundamental drivers are, and then you can kind of get estimates of what the values of those drivers are in the future, and then you can generate predictions going forward. Again, that is out of sample, you know. You have got a historical sample, and now you are projecting into a different time period, even if you are doing that for the same jurisdiction.

And then the third thing is if you want to tailor specific productivity factors for different distributors, so for example, like, within Ontario you could say that there is a rural industry, an urban industry, high-growth industry, low-growth part of the province, and these companies all have different business conditions, and because of that we want to use some econometric information to tailor TFP results that are specific to each of those kind of sub-industries within the industry.

And you might remember in third generation we talked about that quite a bit. And I am planning to talk more about this tomorrow, assuming we get into it, but we walked -- at least I walked right up to the brink of recommending an econometric approach to TFP, and, you know, to using that because of the distribution, because of the diversity issue, and didn't do it at the end, and I am glad I didn't, again for reasons that are policy-related.

But the important thing is that those are the three factors when TFP decomposition is -- those are the three reasons when TFP -- the econometric TFP decomposition approach is warranted.

And none of those three conditions apply here. One, we have a large industry. We have 73 companies. Even if we exclude two we have 71. Two, we are not tailoring different companies -- different productivity factors for different companies. We have one productivity factor for the whole industry. And three, we are not trying to make any allowance for any -- any specific allowance for business conditions in the future. We are not projecting those, and we don't -- we are not, you know, linking those into an econometric projection.

So none of those factors apply, and those are the traditional reasons why PEG has used that approach.

MR. HARPER: Okay. Thank you. I am sure this will come out in the more general discussion tomorrow, but thanks for clarification of where you were coming from.

MS. BRICKENDEN: Are there any further questions?

[Technical difficulties]

MR. TUCCI: Well, maybe -- can you still hear me? Oh, use that one? There you go. Can you hear me?

Larry, you mentioned PEG's typical approach is to use the indexing method. Could you point us to where in PEG's history they have excluded large utilities out of the TFP indexing approach because they did impact the TFP index?

DR. KAUFMANN: Well, I don't think we have ever specifically done that, but we have been sensitive to the need for the TFP approach to be external, and a good example of that is California. Whenever we do TFP estimation in California we do not -- sometimes we'll use regional definitions of the industry, but again, because the California companies, PG&E and Southern California Edison, are so dominant, if you would look at a western US aggregate, they would dominate that.

So we have never used a western aggregate for companies in California. We have for companies in Oregon and others that are small relative to the sample. So we have never had to do it. We have never had a situation like this where there were two companies that were so dominant and so different. Both of those factors matter.

So, no, we haven't done it before, but we have -- but it's certainly consistent with the way we have estimated TFP elsewhere.

MR. FENRICK: So in the California case you would use the entire industry. Would you exclude the individual California utilities, or would you include them all?

DR. KAUFMANN: No, because, I mean, when you do the entire country and, you know, and you get like 60- to 80 million companies -- customers in your sample, then those 5 million customers of any of those -- you know, either of those two companies become small relative to the sample.

MR. FENRICK: Kind of shifting gears a little bit, excluding -- kind of the rationale excluding Toronto Hydro and Hydro One, does it then kind of give you pause to include them in the econometric benchmarking and the unit cost benchmarking results?

DR. KAUFMANN: Hydro One to some extent. Hydro One is different than any other company in the province. I think everyone recognizes that. Toronto Hydro, no, not so much.

I would say, I mean, I think Toronto Hydro is a bigger version of some of the other CLD companies. There are some differences. I will say that in a perfect world we would have more data in this sample for companies that were similar to Toronto Hydro, but that's not what we have.

I would say -- you have talked about the urban core issue. I don't support urban core as a variable, per se, but I do think one thing that I think is worth thinking about going forward is -- what's critical about the urban core is Toronto Hydro has all these assets underground. They have a network, a CBD network, and it's almost all underground. That's very expensive, and there is nothing in the model to reflect that.

So I grant you that that is an issue, but one way we could potentially control for that is, rather than use a percentage of lines that are underground, you could have a percentage of assets that are underground. That data doesn't exist right now, but the Board could start collecting data on companies' assets and how much is underground. And that's one way to potentially control for that and pick up that factor in the model.

MR. FENRICK: I just have one more question. So you said a couple of variables possibly dropped out now that you've changed the cost definition.

What are the business conditions in the model now that are significant?

DR. KAUFMANN: The ones that are significant at the 10 percent level are customers, peak capacity, kilowatt-hour deliveries, kilometres of line, the customer growth proxy, and what am I missing?

MR. FENRICK:  percent underground or...

DR. KAUFMANN:  percent underground and area are out. So there are five variables right now.

MR. FENRICK: Okay, thank you.

MS. BRICKENDEN: Thank you, Steve. Are there other questions?

MR. BROOKER: I am Grant Brooker from Cambridge and North Dumfries Hydro. I will preface what I ask by I am not an economist either, but we have made great pains in talking about the productivity factor excludes Toronto Hydro and Hydro One, and I guess I understand why they are excluded.

But what I don't understand is why they are included in the other unit costs by peer group. If we are excluding them from one area, why are we including them and ranking other utilities on the basis of that by including them in the other one? Can you explain why we include them in one area and not in the other?

DR. KAUFMANN: Yes. The reason is that they are excluded from the estimate of productivity growth for the entire industry, and the reason for that is we want an estimate of productivity growth that is appropriate for most distributors in the province. We have two companies that are dominant and have different productivity trends.

So when you include them, it ratchets down the estimate of TFP growth for everyone. So in that sense, I don't think that's appropriate. But that's different than trying to get inferences on those companies' efficiency, which is what the unit cost analysis is trying to do.

So in one sense, the reason they are excluded is because they are large and they are having an impact on parameters that will impact other distributors in the province. That's why they are excluded.

When you look at just the unit cost work, all we are trying to do is get some estimate of how efficient they are relative to other large distributors in the province, and to do that they need to be in the peer group.

MR. BROOKER: To me it seems like an inconsistency. I understand why you exclude them in one area. You have described it very well.

DR. KAUFMANN: That factor only applies in that area. So when you include them in the peer group, you know, I mean, it's -- they are having much less impact. They are not directly impacting any company's rate adjustment, the formula that will be used to adjust that company's rates, not directly.

MR. BROOKER: But if companies are being ranked according to their efficiencies compared to a factor that includes those two utilities, then, yes, they are being impacted.

DR. KAUFMANN: Indirectly that's one element of the stretch factor assignment.

MR. BROOKER: So companies are being evaluated against Toronto Hydro and Hydro One to determine their stretch factor, as an example, and that does affect what their stretch factor becomes, which then affects -- it runs all the way through it. Anyway, I just don't understand why it's inconsistent.

DR. KAUFMANN: That's the rationale. There is a direct link with the productivity factor. It's much less direct. It doesn't impact the entire industry. It would only impact the companies within that peer group, and it would only have an indirect impact, because that's only one of two tests.

You know, one of the things that was suggested in terms of the peer group benchmarking measures, is not to compare companies to the mean value for their peer group, but to the median value, and, if you do that, then that's something else that can reduce the impact of these outlier sort of companies in terms of unit costs having an impact on the benchmarking evaluations.

So, I mean, that's something that I think is definitely worth considering and something we could potentially look into in our supplemental report.

MR. BROOKER: Thank you.

MS. BRICKENDEN: Chris, I thought you had a question.

MS. AMOS: Just sort of following up on Grant, because I was looking at the same that he was and saying, if you happen to be in the group with Hydro One and Toronto Hydro, your group average is that much higher to be compared against. So, therefore, you would say, Well, they benefit because therefore -- when you compare it. But not only do they benefit there, those percentages which would be higher, which are higher, like, in a probably minus situation than they would be if the two weren't included, are then translated when you calculate the efficiency rankings, so -- and comparing them to other utilities.

So like you just said, maybe if you compare -- I think it was the median, you said, that that may bring it more in line.

DR. KAUFMANN: Right.

MS. AMOS: But it doesn't just impact that group. It does impact all the other utilities, because their percentage, you know, may be shown as less than -- compared to the group average, it shows that they are better off than they would be if the two were excluded.

DR. KAUFMANN: Well, yeah. I mean, it will certainly impact the difference between any given company's unit cost and the mean unit cost for the, I believe, 11 companies in that peer group, peer group A. But that doesn't have any implications on that difference for any of the other five peer groups. So that's a calculation that's internal to the peer group. They do get into the rankings, and it will have, again, an indirect impact that way.

MS. AMOS: But that is where I was going is that impacts the rankings, which then would impact whether you are statistically superior or inferior, would it not?

DR. KAUFMANN: It does have some influence, yes.

MS. AMOS: Okay.

MS. BRICKENDEN: Thank you, Chris. Are there any further questions? Bill.

MR. HARPER: Actually, I just wanted to follow up. Larry, you made a comment about how -- now I guess in response to -- Steve made a comment about how now a couple of the other cost drivers, I think it was undergrounding and area, had dropped out as being statistically -- and you are only left with your four output parameters and effectively customer growth as being the cost drivers.

Now, if I look at how you came up with your peer groupings, we end up with six groups, but you have got output as -- maybe coming the other way, you have got five cost drivers now, four of which you collapse into your output parameter. So effectively we only have two parameters now, output and customer growth. It seems to me we now only have two parameters we are looking at that are drivers. Wouldn't that fundamentally change the way you are looking at your peer group because, one, you wouldn't end up with more than four peer groups, it would seem to me?

MR. KAUFMANN: We could certainly do that. We could now have the quadrants and just use the quadrants directly. So that is a possibility. But, you know, what we looked at here were -- these peer groups are still accurate in the sense that they reflect how companies compare on these business condition variables, right, whether you are above or below the mean or above or below the median.

The only problem is that two of these variables that are used to define these peer groups are now -- they are not statistically significant anymore.

So that doesn't necessarily -- I suppose I can just leave it there, but if people are still comfortable with using these two variables, undergrounding and area, as factors to determine peer groups, if people are still comfortable with those even though they are not statistically significant in the model, then we can retain these peer groups.

MR. HARPER: I guess it's best we just leave it at that then. Okay, thanks.

MS. BRICKENDEN: Thank you, Bill. Are there any further questions for Larry? Well, nothing? Nothing on the e-mail either.

Well, having said that then, perhaps -- I think this morning we said we would do the presentations, and we will call it a day and reconvene tomorrow morning and have a panel discussion, where we will invite Adonis, Larry, and Steve back to have a more general and broad discussion on the matters presented today. Thank you very much.

--- Whereupon the conference adjourned at 3:03 p.m.