BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF THE UTILITIES COMMISSION ACT
R.S.B.C. 1996, CHAPTER 473

And

FortisBC Inc. -
Annual Review for 2019 Delivery Rates

Vancouver, B.C.
October 2nd, 2018

WORKSHOP

BEFORE

R. Mason	**Chairperson**
D. Enns	**Commissioner**

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T. HACKNEY	B.C. Sustainable Energy Association and Sierra Club of B.C. (BCSEA/SCBC)
J. QUAIL S. QUAIL	Counsel for Movement of United Professionals (MoveUP)
L. WORTH	Counsel for British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, Together Against Poverty Society and The Tenant Resource and Advisory Centre (BCOAPO)

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Diane Roy
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VANCOUVER, B.C.

October 2nd, 2018

(PROCEEDINGS RESUMED AT 9:00 a.m.)

Good morning, everyone. Welcome to the workshop for the FortisBC Energy Inc. annual review for 2019 rates.

My name is Richard Mason. I'm the Panel Chair, and I'm joined today by my fellow Commissioner Doug Enns.

Commission staff joining us today are Sarah Walsh, Tanya Lai, and Christelle Irakarama and we're represented by our counsel, Paul Miller.

After introductions, FEI will be following the agenda they distributed on September 24th, which is Exhibit B-7 in this proceeding. For each of the agenda items, they'll be making a short presentation, and then responding to questions on that topic. There will also be an open question period at the end of all the topics.

For the question period, I would ask the interveners present themselves in the sequence that Paul Miller has, I believe, distributed to everyone. Commission Staff will ask their questions after all of the interveners are complete.

I would ask, of course, that all interveners stick to the scope of the proceeding in their questions.

The session will be transcribed for the record, so please use one of the microphones when you're speaking. I believe for interveners there's just the one microphone for questions, yes? Good.

We'll take a break at around 10:30, depending on how the agenda goes, and depending on how close we are to finishing at around noon, we'll either take a break or push on through to the end.

Proceeding Time 9:02 a.m. T2

I would like to start with introductions. And for those introductions, I would ask that you state your name and organization, and spell your surname for the record please. We will do everything in sequence of these names that Paul has distributed.

So, perhaps I could ask for FEI to introduce themselves and anybody on their team that they would like to introduce, please.

MS. ROY: Okay. Thank you, my name is Diane Roy, R-O-Y, from FortisBC. And I think we'll ask the people seated at the T-table here to introduce themselves.

MR. BYSTROM: Chris Bystrom, last name B-Y-S-T-R-O-M, counsel for FortisBC.

MR. GOSSELIN: Richard Gosselin, last name G-O-S-S-E-L-I-N for FortisBC.

MR. WOLFE: Jason Wolfe, W-O-L-F-E, for FortisBC.

MR. CHERNIKHOWSKY: Paul Chernikhowsky, C-H-E-R-N-I-K-H-

O-W-S-K-Y for FortisBC.
MR. WONG: James Wong, W-O-N-G, FortisBC.
MR. ANDERSON: Darwin Anderson, A-N-D-E-R-S-O-N, for FortisBC.
MR. HENDERSON: Brett Henderson, H-E-N-D-E-R-S-O-N, Director of Finance and Accounting for FEI.
MR. LEAVY: Chris Leavy, L-E-A-V-Y, FortisBC.
MR. BAILEY: David Bailey, B-A-I-L-E-Y, FortisBC.
MR. JULYAN: Darren Julyan. J-U-L-Y-A-N, FortisBC.
MR. HIMMEL: John Himmel, H-I-M-M-E-L, FortisBC.
THE CHAIRPERSON: Thank you very much. Do we have Mr. Weafer in the room?
MR. WEAFER: Good morning, Chris Weafer, counsel of Commercial Energy Consumers, and I am joined by David Craig, and Janet Rhodes assisting today. And just an introduction, and I anticipate they may or may not come to the podium for questions, just to give you a heads up. Thank you.
THE CHAIRPERSON: Sorry, do you mean you may not have questions? Or you may choose to do something other than come to the podium when you have questions?
MR. WEAFER: I am just indicating Mr. Craig or Ms. Rhodes may come to the podium as well as be -- in terms of asking questions, if that is acceptable.
THE CHAIRPERSON: Absolutely.
MR. WEAFER: Thank you.

MR. ANDREWS: William Andrews, A-N-D-R-E-W-S, representing the B.C. Sustainable Energy Association and the Sierra Club of B.C. And with me today on the phone is Tom Hackney in Victoria.
THE CHAIRPERSON: Thank you.
MR. QUAIL: Good morning, Jim Quail appearing for MoveUP, and assisting me is my co-counsel Susanna Quail.
THE CHAIRPERSON: Thank you. And is Leigha Worth here?
MS. WORTH: Good morning, Mr. Chair, members of the panel. Lea Worth here as counsel for BCOAPO, and I have nothing to add to the agenda this morning, thank you.
THE CHAIRPERSON: Great, thank you.
MR. MILLER: Mr. Chair, Miller, M-I-L-L-E-R, initial P, counsel to the commission.
MS. WALSH: Sarah Walsh, last name W-A-L-S-H, senior regulatory specialist with the BCUC.
MS. LAI: Tanya Lai, L-A-I, regulatory analyst with the BCUC.
MS. IRAKARAMA: Christelle Irakarama, I-R-A-K-A-R-A-M-A, hearing administrator, BCUC.
THE CHAIRPERSON: Great. Thanks, very much everyone. Sorry, Paul, did you have something to add?
MR MILLER: No, I was just going to say, Mr. Chair, that the introductions are concluded.
THE CHAIRPERSON: Thank you very much. I understand

there is some question about whether anyone is actually attending on the phone. Does that cause of problem?

MR. ANDREWS: William Andrews here, I've had it explained to me that Mr. Hackney is listening on the web, he is not actually on the phone. And we are in touch on the computer, so that's fine.

THE CHAIRPERSON: Perfect, thank you. Great, well thanks very much everybody. With that, I'll hand it over to Ms. Roy from FEI.

PRESENTATION BY MS. ROY:

MS. ROY: Thank you, and good morning. Welcome to the workshop for FortisBC Energy Inc. review of 2019 delivery rates. 2019 is the last year of our six-year PBR term, and this is our fifth annual review, because the first year was set through the PBR process.

I am going to start by walking through the agenda. The presenters that you can see here are as shown. We will be starting off with the approval sought and the PBR overview. Moving into the revenue requirements and rates, which will include a summary of our evidentiary update, and also the revenue surplus and a treatment of the existing revenue surplus. We'll be talking about growth capital, and that is an area where we are continuing to see a strong trend of customer additions that are affecting our growth capital.

We will be talking about integrity management, and sustainment capital, and we will be focusing as well on some of our larger integrity projects that are going to be coming before the commission. We'll be providing a summary of our performance on our service quality indicators, and then as indicated, we'll have the open question period at the end.

So, we have the presenters that you can see here, and as you can see, we also have some additional people to answer questions as they arise. As indicated, please ask questions on the topics that we're presenting on when the presenter is up here, otherwise we do have the open question period at the end for other questions.

So, we are going to start with the approval sought by FEI that were the focus of our application. The first is a delivery rate freeze for 2019. That means 2019 rates would be held at 2018 levels, which are also the same as 2017 and 2016 levels. And that would be accomplished by drawing down the existing revenue surplus deferral account by the amount of 6.319 million after tax, and that is equal to the revenue deficiency for 2019.

Proceeding Time 9:08 a.m. T03

Otherwise, without doing that, we would have a rate increase of 1.1 percent in 2019.

We have four deferral account requests. The first two are new deferral accounts; one for the demand side management expenditures regulatory proceeding, and the other one for the transmission integrity management capabilities CPCN development costs, and Paul will be speaking to that later on, so we all have an opportunity to ask some questions on that.

We have the disposition of two existing regulatory proceeding costs for the long-term resource plan and the rate design application. Then we have the continuation of the existing treatment of the midstream costs of $3.6 million, and that arises because when the PBR term was initially applied for, it was a five-year term, and the Commission extended it by one year, but in the approvals that were given, there was only five years of this treatment approved. So we need to get that treatment approved for one more year for to continue on with that.

And that is really just to make sure that the costs of the Southern Crossing pipeline capacity are recovered from the appropriate customers, and wouldn't be recovered from transport customers. We want them to only be recovered from those that are actually taking gas from us.

We have -- for the first time in the last year here we have Z Factors for FEI. They relate to health benefit changes from the B.C. government. One is a cost and one is a savings for us.

And finally, as we do every year, we have the two delivery rate riders for biomethane variance account and the RSAM, or revenue stabilization adjustment mechanism account. These two rate riders together are actually reductions this year as compared to 2018. So on an annual bill, even if the delivery rate itself is frozen, there would be a 0.2 percent reduction for a residential customer in 2019, with these riders taken into account.

That is all the approvals sought. Any questions on this slide? Okay.

Now, as I said, we're setting the rates for the final year of our six-year PBR term, so I'm going to, as I did last year, summarize what we're seeing so far in terms of results. I'm going to start on this slide with the O&M, the operations and maintenance expense. And then I'm going to talk about capital and then I'm going to touch on rates.

So what this chart shows you is three different numbers, really. What you can see -- these are all, by the way, on an adjusted for inflation basis, so they're all in 2018 dollars. The blue bars are the total O&M in millions of dollars, so it goes from 289 million in 2013 to 270 million in 2018.

The orange line is the total O&M on a per-customer basis, so you can see the decline there. And finally the grey bar is the O&M that's included within the formula. So some of it's flowed through outside of the formula. That's the change in the O&M -- formula O&M per customer over the PBR term.

So what you can see here is that overall O&M has trended favourably both in total and on a per-customer basis since the outset of the PBR term, and it has been assisted on the per-customer accounts by the high customer growth we've had in recent years.

We have had $43 million in O&M savings shared with customers through the earning sharing mechanism, plus another $13 million of savings which is embedded in the formula itself. That's to date.

Any questions on the O&M slide? Chris?

MR. WEAFER: Less a question and just more of process, because I -- and I appreciate what you're doing, sort of breaking for questions after every slide, but as I understood the process was set up is, you'll do your presentation; at the end of your presentation, we'd ask questions on what's been presented. I'm not trying to be difficult, I just want to understand --

keeping the process smooth, because otherwise we might want to slow down between slides to allow people to have some questions. And we're good either way.
THE CHAIRPERSON: Sure.
MR. WEAFER: I guess -- what's --
THE CHAIRPERSON: Do you have a preference?
MS. ROY: I don't, and I'm happy to take all the questions at the end of my session. It might be more -- simpler for people to get up and ask their questions that way, instead of jumping up every time. Is there another preference, Jim?
MR. QUAIL: I would suggest with the exception -- if somebody has a clarification question pertinent to a particular slide, it's probably useful to have that raised --
MS. ROY: Yes.
MR. QUAIL: -- and the clarification taken there and then.
MS. ROY: Okay, great. Thank you. We'll do that then.
THE CHAIRPERSON: So I would just ask, then, if anyone does have a point of clarification, just raise your hand to make it known to the presenter and then come up. Thanks.
MS. ROY: Okay. Okay, so I'm moving on now to the formula capital expenditures, and this is just a reproduction of our updated Table 1-4 on the

application itself.

Proceeding Time 9:13 a.m. T4

What you can see here, this is comparing the formula to the actual expenditures for each of the years in the PBR term so far. And what you can see in the earlier years '14, '15, '16, we were at -- below or close to the capital deadband, which is 10 percent. And what you're seeing in the latter two years, 2017 and 2018, is that we're above the capital deadband in both Growth and Other, which is sustainment and other capital.

And the 2018 figures you're seeing here are higher than what we had thought they would be last year when we filed our application. And there's two main causes of that and they're both related to growth. One is fleet and equipment for our operations crews and the other one is additional costs for the Whistler pipeline IP project. And we'll have people available to talk about those later if you'd like as well.

And I just thought on the capital slide, we've talked about the capital deadband for the last two years, so I didn't prepare the same slides that I prepared in the last two years. I think everybody understands how the capital deadband works. But one thing I would like to touch on is that we did have a directive that we've complied with for the last two or three years which is asking us to provide detail on variances from the formula for capital expenditures, and then we've had a number of IRs asking us to provide specific projects that are causing us to be over the capital formula or maybe they're -- are they within the deadband or are they over the deadband.

So we've done our best to respond to those and I just wanted to clarify why the -- you know, why we have such difficulty responding to those questions. And it's really about how the PBR is set. When you look at the columns we're comparing to, those are really just a 2013 spending allowance that is then being escalated by a formula amount. So what we don't have is a list of projects that ties to that number that we can then compare our actual expenditures to to try to figure out which ones are the ones that are causing us to be over the formula.

And so we have done our best to answer those questions, but you know, under the formula approach it was envisioned that we would use the flexibility afforded by the PBR to move capital between years or reprioritise projects throughout the terms and that is in fact what has happened. And we've had the same issues that we discuss in the Appendix C-4 and also below Table 1-4 in the application where we talk about some of the challenges we've had. And for growth capital a lot of that has to do with the level of growth that we've seen and also some issues regarding a change in the mix of the additions that we're having for a growth capital.

And then for sustainment we had an issue with how the base was set for the term and also we've had, as I discussed just now, that there's some growth related capital projects that are also driving sustainment capital level up. And Paul will be able to talk about some of those kind of things when he's up.

Proceeding Time 9:16 a.m. T05

And what happens is the further we get into the PBR term, the more these things become magnified, because there's things that are occurring that weren't considered when the base was set for the PBR term. And so that's one of the reasons you're seeing certainly growth -- the growth capital is related to more to growth of the system itself and our customer additions. But on the other side, some of those things are starting to arise and are becoming more and more difficult to manage within the formula capital, in addition to the fact that we had an additional year added onto the PBR term that we didn't have, or we hadn't envisioned when we set it out.

Now, the deadband was set to accommodate year to year variances in growth -- or in all capital, rather. And I still think that's a good mechanism. It does -- it is set to consider the normal level of fluctuation in capital, and I think it's accomplished its goal. And it's worked effectively certainly in the earlier years of the PBR term.

But all of these things I've talked about today, the reason I mention them is really these are all the things that we're going to be addressing in the next PBR term. And I know we've had a lot of questions about what we're planning, what it's going to look like, and we are going to be meeting with everybody to discuss that over the next month or so, I believe it is.

Okay. So I'm going to move on to the final item here, which is the rates. And on this slide here, what you see is CPI/AWE actuals for the year shown, and then the delivery rate increases. In the earlier years we had increases, you know, generally in line with inflation. And then recently we have had no rate increases, although I will note that we did have a revenue deficiency in 2019 which would have otherwise resulted in a 1.1 percent rate increase.

And overall over the PBR term, think about the rates, what has allowed us to accomplish this.

One is the O&M savings that we've able to realize, not only within the formula, the productivity improvement factor in the formula, but also the O&M savings about the formula. We've had lower interest rates. We certainly had strong growth in customer demand, which has helped to offset any rate increases that otherwise would have occurred from things like adding in some large capital projects. We've added in the Coastal transmission system project, Tilbury expansion, and also in 2019 we see the first tranche of the -- I'm going to call it the Coquitlam IP product. And it's the part that's related to the Vancouver and Burnaby segments of that project. So they're both coming into rate base. That part's coming into rates in 2019.

So overall when you look at just, you know, these three slides by themselves, and considering SQIs as well, I would say we've had good results for customers. And I think -- I feel like these annual reviews have been a fairly efficient way to review our progress as we go through the term of the PBR. And I think embedded in our culture now is kind of more of a long-term planning focus and the sort of focus that really the PBR was set up to incent in the utility.

So I'll just close with this slide on major initiatives. This is from Appendix C-2. And this was also from a Commission directive that we provide this detail each year during the annual review. I won't walk through these, because the first six of them were all not new this year. They were all ones that we've discussed in previous years. The two new ones this year are gas workforce management and common trenching.

And I will pause here for questions. Next person up will be Rick Gosselin who will be talking about the evidentiary update, revenue deficiency, and the treatment of the revenue surplus.

Proceeding Time 9:20 a.m. T6

MR. WEAFER: Thanks, Diane. Just a couple of high level questions for the introduction. This is the last year of this term of PBR, and I know there was a number of questions around what is next, and the company has stepped back from answering those saying that's still in the works. But can you give us -- you just made a comment that the company is now focused on long-term planning, and we're now a year away from this being over. Can you give us any high level comment on what do you see for the next PBR term?

Because I think the evidence and responses, the low-hanging fruit is gone, and there is not much opportunity. So, can you just give a little bit of an overview of what we may see a year from now in terms of the company's view, recognizing it's a work in progress and it may change. But, we don't intend to have a lot of questions today, because this is the last year of the five-year term, and we are very focused on what is next, and this very significant CPCN we just heard about is going to affect our view on the PBR as well.

So, can you just give us a little bit of a hint as to what you see for the next PBR term?

MS. ROY: Sure, I could respond to the high level. And I would note that we do have meetings set up with everybody over the next two weeks or a month, James?

MR. WONG: Mostly in October.

MR. WEAFER: That is the benchmark meeting?

MS. ROY: No, the benchmarking is a separate discussion. So this is just to walk each one of you through what we're thinking about for the next PBR, and we would be happy to address in more detail then, because as you said, we do have a fairly strong view of what we're going to be filing at this point.

MR. WEAFER: Okay.

MS. ROY: I would tell you it's not that different than what we have now. The same kind of general structure, where you have a number of items. Most items being forecast on a cost of service basis annually. We continue to have O&M and capital, or at least the bulk of it set by formula. Some changes, we'll have to be re-basing O&M and capital, and we also will be adjusting some of the formulas for growth capital. And you know, the more minor things I won't discuss here, but that is the basic framework for it.

MR. WEAFER: So at a high level, just on a basic point, and I'm not going to go far on this, but how do we understand that we've received the benefits of this PBR period if we are now re-basing for the next period?

MS. ROY: Well, I would say, as I just showed you when we're talking about O&M in particular, the O&M is lower than it was at the beginning of the last PBR term. So, I think what we're seeing there is some imbedded savings that are not going to be eroding when we go into the next PBR term. There is going to be some considerations for different areas we need to focus on with this longer term view that we're talking. And so you can't expect to see a starting base and then some adjustments to it. But I still think you're not going to be seeing -- you definitely won't be seeing an erosion of PBR benefits, if that is the concern. Those savings are embedded.

And further to that, when we talk about the numbers, there is -- the PBR is set up so that we're achieving the productivity improvement factor, which we have. On top of that we've achieved additional savings. But I think a PBR is a success just by achieving a productivity factor in the first place. So we have gone over and above that, and I think we can continue to at least see us achieve a productivity improvement factor in the next PBR term, at a minimum.

MR. WEAFER: So, last question on it. So, are you re-basing O&M? Is that the proposal?

MS. ROY: O&M and capital.

MR. WEAFER: So the savings, as we're looking at the efficiencies obtained and where we're at, why would that be re-based? I mean, that is the benefit of this five year term.

MS. ROY: Re-basing, maybe it means something different to you. To me it means resetting the cost to reflect the actual experience.

MR. WEAFER: We can deal with that -- I don’t want to probe that any further. So, again, at a high level, and we've seen the O&M savings, and then we've seen the capital formula not working, and we've seen the sort of hockey stick impact on capital the last couple of years in particular and you focused on growth capital, but the last couple of years it's been other capital where we're seeing the variance from formula. And is that partly sustainment capital? Is that in that other --

Proceeding Time 9:13 a.m. T7

MS. ROY: Yeah, the two big areas -- and Paul actually I think has a slide on this, but the two big areas where we're seeing variances are in the in-line inspection area. Is that right, Paul? Yeah. Inline inspections and also some of the items that we have classified as sustainment capital but they're more of the system improvement variety. They're growth related, so that they're in sustainment capital, but because they don't grow linearly with additions to customers, but at some point you will have a large project that comes into play, so something like the Whistler IP pipeline would be an example of that.

MR. WEAFER: And this is something that, not being an accountant I wrestle with in the terms -- and just trying to get an understanding at a high-level the sort of sustainment capital area where we're seeing growth and the crossover between O&M and sustainment capital. Because when I hear sustainment capital described I oftentimes think it's actually the normal O&M and making sure the system is safe and reliable and the integrity is there.

And, again, when we see this capital hockey stick move the last -- in the graph the last couple of years and now we -- and we'll talk about this large CPCN, but in response to one or two of the IRs even there there's a question as to what's sustainment capital, what's O&M. And as you know CEC's always had a challenge with PBR.

But that's one of the areas we'd like to get a clear and better understanding as to what is moving to susta- -- particularly if there's changes to the term moving to sustainment capital versus what's an O&M saving over here and a sustainment capital expense over here. Customers generally like capital that's improving the system, but if the company is getting an earning sharing benefit by shifting -- so how does the company manage that and ensure that a sustainment capital investment is not an O&M reduction?

MS. ROY: I'm probably not the best person to answer that question. I might ask you to save that for Paul when he comes up.

MR. WEAFER: That's just one of the themes that we're --

MS. ROY: There are --

MR. WEAFER: We have trouble over it every year and now we've got a very significant CPCN, a billion dollar CPCN that arguably has -- well, we're deal with that with the panel.

MS. ROY: Yeah.

MR. WEAFER: But it's the high-level theme we have a concern about, so --

MS. ROY: Pardon me?

MR. WEAFER: It's the high-level concern that we have in terms of the workings of PBR, and particularly where we're seeing the capital not working and O&M apparently working, so.

MS. ROY: Yeah, and I do think the next PBR application, which is coming very soon, will be a good time to, you know, embed the learnings we have from this one and explore anything, any questions you have like that further.

MR. WEAFER: And so last on that, when do you anticipate filing that?

MS. ROY: It should be very early next years.

MR. WEAFER: Okay. Thank you. I'll just see if David or Janet have any questions.

David, David Craig.

MR. CRAIG: Panel, David Craig for the CEC. I just wanted to see if you could give me a little more background on the 6.319 million coming from the revenue surplus deferral account. Can you give me an idea as to what the balance remaining is in that account?

MS. ROY: I could, but actually Rick is going to be up next and that's one of his topics, so I'll leave it to him to do a better job than I would.

MR. CRAIG: Perfect. Then I'll hear it from him.

MS. ROY: Okay. Thank you.

MR. CRAIG: Thank you.

MS. RHODES: I just wanted to talk about the calculation of the capital deadband. So in CEC 1.3 we pointed out that you can't add 10 percent of one number and 20 percent of another number and come up with 30 percent of any number. So we're just going to go on the record that that calculation isn't rational. We realize it's part of the part of the PBR decision, but we're just going on record that it doesn't make any sense.

MS. ROY: Yeah. It was not something we proposed. The two year deadband is not something we proposed, and so it's not something we would propose to continue, and so hopefully it will not be a problem going forward.

MR. RHODES: It just has to be an average or some other calculation.

MS. ROY: Yeah, sure.

MS. RHODES: Okay, thank you.

MR. ANDREWS: I just wanted to mention that Mr. Hackney and I had the benefit of Fortis's presentation to do with the upcoming PBR application yesterday and it was quite detailed and had a lot of information. So for those interveners that haven’t received it, there will be more information coming I presume if they participate in that.

MS. ROY: Thank you, Bill.

Proceeding Time 9:29 a.m. T08

MR. QUAIL: First of all I'd just like to make a comment in response to the words that prefaced my friend Mr. Weafer's questions, which appear to assume that there will be another PBR term after this one. And first of all for the record I want to state that we don't assume that there will be another PBR as the regime that follows this one.

Second, a question. I believe you understand that the Commission will need to make a determination whether or not another PBR term is the appropriate regime to be regulated under.

MS. ROY: Of course. We will bring forward a PBR application and the Commission will determine if they approve it.

MR. QUAIL: But not only that, but whether PBR --

MS. ROY: Certainly.

MR. QUAIL: -- generically is the appropriate strategy.

MS. ROY: Certainly.

MR. QUAIL: And we'll need to determine whether it is working, and in what respect it's not.

MS. ROY: Mm-hmm.

MR. QUAIL: And whether it is a superior regime in terms of the duties that you've got under the *Utilities Commission Act*, and the traditional costs of service regime. You understand that?

MS. ROY: Of course I understand that, Jim.

MR. QUAIL: Okay. Because the discussion appears to -- point of departure seems to be, we're into another PBR and we're -- the only question really is how that is going to be designed. I just wanted to be sure it's clear in everybody's mind, the question of whether or not it's PBR is very much an open question, legally and also for practical purposes.

Can you identify any concrete benefit that ratepayers have obtained as a result of PBR? That is, something that FEI has done for them in the last five years, that it would not have done otherwise? Concretely.

MS. ROY: We've had a number of IRs on that same question, Jim, and I think we've answered it. The answer is that it's very difficult to compare to a hypothetical situation because we don't know what the cost of service regime would have looked like during those PBR terms.

What we do know is what the results of the current PBR regime have been, and they've been positive. That's really all I can say on that. And I can speak to the culture of the company, and I can speak to the regulatory efficiency, but I cannot point to one item in particular.

MR. QUAIL: In other words, the answer to the question is "no".

MS. ROY: The answer is, other than those things which I've already pointed to, which are rates and O&M and service quality indicators, and I can also do a comparison of the regulatory costs, the answer would be no other than those things.

MR. QUAIL: Well, for example, you discussed O&M with my friend Mr. Weafer. When you say that O&M is down, that is per customer.

MS. ROY: And in total, I believe, too. I'd have to go back to that slide. I'm pretty sure it was in total as well.

Yes. It is down in total from $289 million to $270 million, and that includes the stuff outside the formula.

MR. QUAIL: But the reduction per customer, according to your own comments, are largely a function of customer growth.

MS. ROY: Well, whether that's true or not, the total O&M is also down. So I don't understand what the relevance of that question would be.

MR. QUAIL: Well, it's claimed on behalf of Fortis and other utilities who enjoy being under a looser regulatory leave -- or leash, rather, that PBR is a strategy that unleashes all kinds of pent-up possibilities in terms of achieving efficiencies and benefit for ratepayers. Right? Isn't that the essential argument made for PBR?

MS. ROY: There's a number of arguments, that is definitely one of them.

MR. QUAIL: And that, for example, having the earnings sharing provides a financial incentive to the utility to perform even harder to try to achieve efficiencies for ratepayers.

MS. ROY: I would actually disagree with that. Most PBR setups do not have an earnings sharing at all, which means the utility retains 100 percent of any savings. So I would say the earnings sharing reduces the incentive for the utility to find those things.

MR. QUAIL: And the earnings shavings -- I won't go to the IRs, but I'll put it to you that what's actually been achieved and shared with customers would perhaps buy a half a cup of coffee a year per customer. Isn't that correct?

MS. ROY: I don't think that is the measure of the success of the PBR term.

MR. QUAIL: But isn't that --

MS. ROY: The earnings sharing by itself, as I've said, is not the measure of it. And we've put out a number of other measures. And Jim, you can disagree with me, but that is my view.

Proceeding Time 9:34 a.m. T9

MR. QUAIL: Do you intend in your application to incorporate a similar earnings sharing mechanism?
MS. ROY: If we did not, we would then be retaining 100 percent of the savings, so it wouldn’t seem fair to customers to do so. So no, we would plan on providing a similar earnings sharing mechanism.
MR. QUAIL: Retaining the savings --
THE CHAIRPERSON: Mr. Quail, I wonder if I could ask you to redirect your question more to the 2019 rates application? Just keeping focused a bit, please.
MR. QUAIL: Well, with all respect, Mr. Chairman, in my submission the fundamental reason for these annual checkups through the annual reviews in the context of the looser regulation is to check whether or not PBR is working. Is this working or not? Is it achieving? It is claimed that it achieves results that would not be otherwise achievable. Loosen the leash and there will be things achieved that would not be otherwise. That, in my submission, is the essence of the argument for PBR, and in my submission it is perfectly within bounds, in fact as the core of what the annual review is about, to look at whether or not in fact the PBR is delivering anything tangible. And we've heard nothing tangible.

I'll leave it at that, because I know I'll have an opportunity to present argument, but I'm

saying they are unable to point to anything tangible that they have provided to --
MS. ROY: I have provided a number of tangible things.
MR. QUAIL: -- anything tangible in terms of something of value provided to ratepayers that you say would not have been there under --
MS. ROY: I think we've provided reduced rates, or no rate increases, and what else could be of more value to our ratepayers?
MR. QUAIL: You have the same obligation --
MS. ROY: But anyway, this is argument as you said, so let's leave this for argument, could we?
MR. QUAIL: You recognize you have the same obligations no matter what regime we're on to achieve whatever efficiencies you can for ratepayers that deliver value and don’t compromise reliability and other obligations?
MS. ROY: That's true, and we do that.
MR. QUAIL: Okay. And I hear you saying, just to be clear, so we get into argument I know what your position is, that the point of the earnings sharing received by the company is not about an incentive. It is about in effect giving back to customers what otherwise you would retain under the PBR regime.
MS. ROY: That is how most PBRs are structured.
MR. QUAIL: That's not my question. Your position is

that the purpose of --
MS. ROY: The purpose of the earnings sharing is to align the interests of the company and customers, so that we're both working towards a similar goal.
MR. BYSTROM: Jim. Jim.
MR. QUAIL: That sounds to me like the same argument that a financial incentive that is shared, incents you to behave in a particular way and you've responded to our questions, that the incentives have had no impact on the way that you have operated.
MS. ROY: Okay, I would just like to just leave this for argument or for next year's PBR application if I could.
MR. BYSTROM: Jim, this is Chris Bystrom, counsel FortisBC, and I think this is well beyond what we need here today. It has devolved into argument. There is a time for argument, and I think it is just time to move on. I'd ask the Commission to assist us in that matter if they would, please.
MR. QUAIL: Well, I say that we're entitled to know what your position is on these questions before we respond in argument, but I think we've covered the ground that I need to present the arguments that I intend to make.
MR. BYSTROM: Yeah, and I think you did many years ago. We went through the PBR proceeding in detail and all these positions have been well known to everyone for

many years.

MR. QUAIL: The difference is that was perspective. We are now looking at retrospectively with five years of experience, and the most important question before the Commission now is how is this working? How has it performed, is the most important question. And I will be addressing that, and it is fundamentally different than it was, with all respect, when this was a hypothetical perspective process. When the PBR was originally designed. I will save the rest for later.

THE CHAIRPERSON: Thanks, Mr. Quail.

Ms. Worth?

MR. MILLER: Ms. Worth has no questions.

THE CHAIRPERSON: Thank you. Back to you? Do we have staff questions, please?

Proceeding Time 9:39 a.m. T10

MS. LAI: This is Tanya Lai, Commission Staff. I just wanted to clarify a few items regarding the gas workforce management initiative. In the response to BCUC IR 5.3 FEI states that the O&M expenditures for the gas workforce management initiative have increased since the application was filed due to unaccounted for training expenses being identified.

The original O&M cost provided in the application was $0.7 million and that has now increased to $1.12 million, which is a difference of

$420,000.
Could you please clarify if the entire increase is due to training expenses?
MS. ROY: Sure, I'll ask John Himmel to respond to that question.
MR. HIMMEL: Yes, the entire increase is a result of training costs, both logistics and training material preparation.
MS. LAI: Could you please explain why there's such a large increase in the training costs and if possible, in an undertaking provide a breakdown of these costs?
MR. HIMMEL: The reason for the increase is that the development of the materials, as we explored the requirements of gas workforce management is that we realized that the extent of the training was going to go far beyond what we initially spoke in the project, and so we had to do an additional training, additional materials to develop for the program. And yes, we can provide a further breakdown of the (inaudible).
MS. LAI: Great, thank you.
MS. WALSH: Sarah Walsh with the BCUC. I just have a series of questions about the operating and maintenance expense savings, and I guess tied to the last slide of the presentation related to the major initiatives.
I'm wondering if you could sort of

specifically discuss with regard to the initiatives that are on the slide, if any of these have been for the purpose of mitigating the cost pressures that are resulting from the growth in FEI's asset base, and if so, how?

MS. ROY: Sorry, could you repeat the question?

MS. WALSH: Sure. When we are looking at the cost pressures that FEI is experiencing, and I think especially in response to BCUC IR 1.1 there is quite a detailed explanation. I was just wondering if you could tie that to some of the major initiatives that have developed over the PBR, for example like Project Blue Pencil, regionalization initiative, and just explain if any of those have assisted in mitigating some of the cost pressures or if they had been in response to the cost pressures that FEI's experiencing.

MS. ROY: James might have to add more. I think that -- well, James, I'll let you answer first.

MR. WONG: You want me to answer first?

MS. ROY: Yeah, sure.

MR. WONG: For the discussion I'll refer you to the BCUC IR 1.1. I think that what we tried to do is provide a kind of general overview of how formula O&M savings are calculated and how cost pressures and productivity improvement factors kind of all interlinked to one another.

So specifically in response to your question, I think it contributes to it, but it's hard to say exactly whether it helped contribute to the productivity improvement saving component, or whether it helped formulaic O&M savings. So there's kind of a combination of things.

MS. WALSH: Okay, thank you. And then just continuing on with that IR response, I just wanted to clarify, there's a portion, I'm going to say at the bottom of page 3 in BCUC IR 1.1 where you discuss some of the other cost pressures that FEI is managing.

Proceeding Time 9:43 a.m. T11

And I just wanted to clarify for example when FEI is talking about vehicle fuel and insurance costs, if in particular the insurance cost pressures that you're describing would impact O&M inside or outside the formula?

MR. WONG: Both. So, just for clarification, the definition of "inside" and "outside" of O&M. Outside of O&M categories of work included are capital work, deferral work. And of course inside of O&M is the PBR O&M. There could be both amounts of O&M, so -- vehicle insurance costs run through our accounting in terms of affecting O&M and capital. So that's the answers, yes.

MS. ROY: So, sorry. I think, James, the question is, we do have insurance that is flowed outside of the formula.

MR. WONG: Yeah. Yes.

MS. ROY: And I think her question is, is the vehicle insurance included in amounts flowed outside the formula or within the formula. And I don't know the answer to that myself. And we could do an undertaking if we don't know the answer to that.

MR. WONG: Just so I understand, the question is that vehicle insurance costs inside of the formula for O&M, or outside of the formula. Is that the question?

MS. WALSH: Right. So I guess -- so the purpose, if you go back to BCUC IR 1.1, like the question itself was asking questions around FEI's new cost pressures it's experiencing with respect to O&M inside the formula.

And it would appear that perhaps some of the response, especially in that bottom paragraph on page 3, are talking about things like municipal fees, vehicle and insurance costs, and so the question is just, are those -- is that response related specifically to costs inside the formula or would some of those costs be related to the flow-through items outside formulaic O&M?

MR. WONG: Specifically in the response, it refers to the costs inside the formula.

MS. WALSH: Okay. Thank you.
MR. WONG: Sorry about that.
MS. WALSH: Thank you.
THE CHAIRPERSON: Any other questions?
MR. MILLER: That concludes Staff questions.
THE CHAIRPERSON: Thanks, Paul. Back over to you, Mr. Gosselin.
MR. GOSSELIN: Good morning. It's Richard Gosselin.

I'll start my presentation by discussing the changes to FEI's application filed with our evidentiary update last week on September 26.

First as described in the application, Section 1.5, FEI plans to amortize a portion of the 2017/2018 revenue surplus deferral account, which will enable FEI to hold rates -- hold delivery rates in 2019 at the same levels as 2018 approved, RDA approved levels.

The evidentiary update last week increased the deficiency by about $4.4 million. That's up from the $3 million that was in the application. FEI, as I said, proposes to hold our 2019 rates at the approved levels by amortizing some more of the 2017/18 revenue surplus deferral account.

So item 1 on the table that you see here is the RDA or rate design application approved rates.

On July 20th, I think it was, or

thereabouts, FEI received approval of its rate design application from the Commission, and we received a number of approvals in that, which included changes to some of our charges and changes to our deliver dates and basic charges for most of our rates -- most of our rate schedules.

Proceeding Time 9:47 a.m. T12

So when you apply these rates from the 2016 RDA to our 2019 forecast of customers and demand, we see a revenue shortfall of about $2.1 million. $1.33 million of this shortfall comes specifically from reduction in our return payment charge from $20 to $8, and a reduction in our connection charge from $25 to $15.

The balance of the 2.1 million, or $740,000, comes from the RDA approved delivery rates and basic charges applied to the 2019 customers and demand. So the total of those two ends up being about $2.1 million of shortfall in 2019.

The second item on the list there, or on the table rather, is this is the same thing we do every year. So, when we file our application we use a couple of indexes from our Stats Can -- from Stats Can, rather. One is the CPI and one is the average weekly earnings, or AWE. When we file, only the May AWE is available. And the way the PBR decision was determined, we were to use all the way up to June. So, what we do is we use a placeholder for June when we file our application, and then as Stats Canada produces the June AWE, we include it in the evidentiary update.

So, we've done the same thing again this year in the evidentiary update, and included the June AWE. And that causes a slight deficiency of $12,000 in the evidentiary update.

The next item is our Kelowna lease in/lease out, or LILO termination. FEI has about five lease arrangements of this type with municipalities throughout the interior of B.C. Within these agreements there is a provision to terminate the capital lease at year 17 of a 35 year term. And so FEI has made the decision to terminate the Kelowna LILO capital lease at year 17 this year. And due to the disparity in the embedded cost of financing and the expected marginal rate of refinancing, terminating the LILO capital lease and refinancing at market rates provides a slight benefit to our customers. In 2019, it provides about a $600,000 reduction in cost of service, or surplus, and over the remaining 18 years of that lease it is expected to provide approximately $5.9 million benefit for our customers.

The next item on the list is our 2018 CapEx projection. So, FEI increased its 2018 projected capital expenditures by $7.2 million, based on a revised cost assessment for the Whistler IP extension as described in response to BCUC IR 1.8.11.

This project was initially planned to be constructed in phases over the course of three years, somewhere between the years of 2015 to 2020. Due to the higher anticipated growth in core, and the conversion of Whistler's bus fleet to CNG, the forecast demand has accelerated the project so that it needs to be undertaken in 2018. So we increased the projected capital in 2018 for that amount. That causes about a $700,000 increase in the deficiency in 2019.

The next item is described as prescribed undertaking 3.6. Just shortly after filling our August 3rd application, FEI found an omission with respect to the spending related to prescribed undertaking 3.6. This section of the greenhouse gas reduction regulation, or some people refer to it as the GGRR, allows for expenditures for feasibility studies and development costs related to shoreside assets.

Proceeding Time 9:52 a.m. T13

FEI has updated the 2018 projected spending to 4.7 million and a further 0.3 million spending in

2019. These amounts are placed into FEI's GGRR incentives account and amortized over ten years according to the determination by the Commission. That item there added about $670,000 to the deficiency in 2019.

And then finally on the table we have our flow-through deferral account update. Items 1, 3, 4 and 5 all have in impact on our 2018 flow-through deferral account calculation, and consequent amortization of the flow-through in 2019 revenue requirement.

Evidentiary update last week -- filed last week rather, provides a reconciliation as Table 1 in the application but I'll summarize it here. The RDA approved rates, as I discussed earlier in item 1, will actually be implemented on November 1st, 2018. Again, when we apply these rates to 2018 forecasted customers and delivery revenue -- sorry, delivery demand, we see about a $1.1 million shortfall in 2018.

So again, we have rates in place in 2018 now. When we take the approved rates from the RDA and apply them starting November 1st, we see a small shortfall at the end of 2018 based on that.

The Kelowna LILO termination provides about a $92,000 surplus in 2018 and the rest of the items amount to about $100,000 in deficiency.

So all of these affect the 2018 flow-through deferral account calculation and reduce the amount returned to customers in 2019 through amortization by about $1.1 million or $1.6 million before tax.

All of these items in the table total to about $4.4 million which FEI has proposed to pull from its 2017/2018 revenue surplus deferral account to hold our 2019 rates flat -- or rather at 2018 RDA approved levels.

My next slide is an update to the waterfall graph that we include in section 1.5 of the application. So as a reminder, this graph show the components that are driving the differences between our 2018 approved revenue requirement and the 2019 revenue requirement as filed in our evidentiary update. And all these items are explained on page 16 and 17 of the application.

Column 1 is demand forecast. So we have a demand pick-up in 2019 over 2018 which is predominantly from industrial demand increase of about 6.3 PJs so that's contributing as a surplus into the deficient -- into the total net costs in 2019.

Column 2 is other revenue, and this is down slightly from basically the RDA decision as discussed earlier. A couple of our fees are a little bit less, or charges are a little bit less and that contributes to a small deficiency in 2019.

Column 3, we have an O&M increase. Most of it is from formula, and a little bit of a decrease in our forecast O&M in 2019.

Column 4 and 5, depreciation and amortization and earned return. The increases to these two are predominantly from the first phase of LMI PSU or the Coquitlam IP line coming into service in 2019. And they are partially offset by a decrease in deferral amortization.

Column 6 is taxes of about $900,000. Taxes are complicated but they are the effect of all the other things being piled on top of the changes from 2018. So things like rate base and revenues, et cetera.

Column 7 is the 2018 surplus. So this was the 2018 cost item to bring the revenue surplus to zero last year. And in 2019 that cost item no longer exists. Therefore, when compared to '18 it shows a reduction in '19.

Proceeding Time 9:57 a.m. T14

And finally column 8 is the 2017/2018 amortization of the revenue surplus deferral account. Before amortization of this deferral account there's about a $6 million deficiency as described earlier.

FEI proposes to amortize a portion of our revenue surplus, the 2017/'18 revenue surplus deferral account to hold our delivery rates flat with 2018 RDA approved. So that's why you see the item there that brings the cost down to the level of zero.

So that summarizes the items that are causing the changes from our 2018 approved to our 2019 proposed.

Chris?

MR. WEAFER: Could you just spend a little more time on that 2018 surplus 5 million? Could you just describe that in a little more detail? So was that an over collection from ratepayers?

MR. GOSSELIN: Yes, it was in 2018. And that amount actually went into our revenue surplus deferral account in 2018. So in 2018 we were a little -- our costs were a little less than the revenue that existing rates would've provided. So last year we proposed to hold rates flat and recognizing that we were going to over collect. And so what we did was we take the over collection and put it into this 2017/2018 revenue surplus deferral account to give back to our customers at a later date.

MR. WEAFER: And maybe this is in an IR response and I can be directed to them, can you just walk me through how -- so that could happen again this year in terms of we come out of the PBR with a forecast and we end up charging more than your forecast? So flush it out a little bit more for me if you don't mind.

MR. GOSSELIN: Yeah, it's kind of a complicated thing when you look at -- if you looked at the earn return statement or the utility income and earn return statement in 2018 you'll see all our cost items like O&M, depreciation, insurance, taxes and such. And then you also see this item in there called "2017/2018 revenue surplus item." And it shows up as a cost item on the 2018 utility income statement as a forecast for upcoming rates, and this was last year.

That cost item didn't actually exist, but we put it there to basically plug the expenses so they match the revenues, recognizing that expense is not a real expense, so we collet the dollars and we actually put it into a revenue surplus deferral account, which is in our deferral accounts. That amount attracts AFUDC and is basically an over collection from our customers in 2018.

So in the 2018 utility income statement that's what you see. In the 2019 one as filed you won't see that item. So, again, this waterfall graph is comparing 2018 to 2019. So that debit or that cost item dies not exist in the 2019 one anymore, so therefore you show in this waterfall graph a credit or

a reduction in the costs of the utility as compared to 2018.
MR. WEAFER: Okay. So the over collection in 2018 is enabling you to smooth out in 2019 is the proposal?
MR. GOSSELIN: Yes. We discussed this a fair bit last year. I think there was an undertaking as well from the CEC that discussed different options for what we plan to do with the 2017/'18 revenue surplus deferral account. So, yes, it went into a deferral account and we talked about different amortization mechanisms and so on.
MR. WEAFER: Can you refresh me what the number was in 2017 going into 2018?
MR. GOSSELIN: So in 2017 I believe we added close to -- you know, I can't recall precisely, but --
MR. WEAFER: Maybe you can undertake to just provide that afterwards.

Information Request

MR. GOSSELIN: Yeah, I think so.
MR. WEAFER: That's fine, yeah.
MR. GOSSELIN: It's an easy one to get for you anyways.
MR. WEAFER: Thank you.

Proceeding Time 10:02 a.m. T15

MR. GOSSELIN: Yeah. So back to David Craig's question earlier, he asked what the balance is in our 2017/2018 revenue surplus deferral account. And the balance at the beginning of 2019 is about $30 million. FEI proposes this year in 2019 to reduce that by about $6.6 million to hold our rates flat with our 2018 RDA approved rates. So, the idea was that we do have a deficiency before amortization of this account. We have this account of over collected revenue that we want to give some back in 2019 certainly, to hold our customer's rates flat. That's the proposed. So at the end of the year it would be about 25 million left in it in 2019.

As an undertaking last year again, we discussed many different ways to amortize this account. So, I've shown a couple options here for discussion purposes.

First, some of the underlying assumptions behind the future years here. So, the underlying assumption is that the balance of the LMI PSU project enters rate base in 2020. So we see a fairly large balance of the project entering rate base of that year. And it causes some costs for our customers. I don't have any other major projects included in our forward years here, but I did assume just a general cost increase of about 2 percent per year starting in 2020.

So, option 1 is essentially FEI's proposed option. So for 2019 we hold rates at the 2018 RDA approved levels, exclusive of riders, by amortizing about $6 million from the revenue surplus deferral account, and then use the balance over the next few years to mitigate rate impacts from LMI PSU, and other unforeseen items that may come up in the next few years.

Option 2, would be to let our 2019 rates increase by the deficiency. This would lead to about a 1.1 percent increase on delivery rates, and it would lead the surplus balance at its current level of about 30 million, so we would take nothing out of it in 2019. Then again, use this balance over the next few years to mitigate rate impacts of the LMI PSU, and again, other unforeseen items.

My main point is that we should not attempt to set the 2017/2018 revenue surplus deferral amortization in this application but rather use it as a tool to mitigate rate impacts over the next few years. So as we propose in the application, we propose to take some out of it, but not to say we're going to give it all back over the next four years by using some kind of amortization of -- equal amortization over four years. But rather we're proposing to give back enough to hold rates flat, and then wait until next year again to see what happens in the revenue requirement, and to again use this surplus

balance to mitigate rates perhaps in 2020, and so on.
That is all I have on the slides.
THE CHAIRPERSON: So, do we have any questions on the subject?
MR. WEAFER: Chris Weafer, Commercial Energy Consumers.
So we're going to spend a little time on the surplus offline, but in a perfect world, in terms of PBR and the signal to the ratepayer in terms of you being efficient or not, or finding savings to some extent theoretically you're hedging by having this surplus. Because if you go over, you have got a way the customers have already paid for it to smooth out the rates. Is that a fair comment?
MR. GOSSELIN: I think as Diane had spoken to earlier, there is a number of successes. Metrics that we call successes in the PBR, things like our O&M per customer, the fact that we have had the PIF built into both the O&M and the capital. And then the SQI. So we have a number of things that are bringing cost down, certainly. The demand has been -- the increase in demand from customers has certainly been a little bit of a boon, and we've held that in surplus account.
So I wouldn’t say it is an offset to future costs, I would say it is something that could help customers when larger projects come online.
MS. ROY: So, Chris, just to more directly answer your

question. I think we had a surplus, and rough math, if it’s 30 million now, then it was 7 million for 2018 and 2017, must have been 23 million.

MR. GOSSELIN: Yeah, about 20, yeah.

MS. ROY: Just to answer your earlier question. We had a rate surplus in 2017 and in 2018. Otherwise we would have had a rate decrease in those years. And had we done that, and as you can see as Rick is just saying here, the deficiency for this year is 1.1 percent. So even if we do flow through the actual deficiency this year, it is still well below inflation, and I think that is a success on the rate front and at surplus in those prior years, you know, we just held rates flat. But otherwise we would have seen a decrease in those years.

So, I don’t think it has masked the PBR results. I think it has demonstrated the PBR results. And yes, if we -- certainly for this year if we go with a zero percent rate increase, it would be probably fair to say that it is masking it. But otherwise, it would be 1.1 percent, which I think is a reasonable level as well.

Proceeding Time 10:08 a.m. T16

MR. WEAFER: And I am not taking any issue with any of that. I'm just more of a philosophical basis in terms of let's assume you haven’t done so well with it, and you'd under collected but now you're going into prior surpluses collected to smooth it out, and the appearance is that the utility has been operating all under PBR when really its prime over collection from ratepayers which is mitigating the rate increases.

So I’m looking at the environment where rates would have been going up because of --

MS. ROY: But by 1 percent, yes. Yeah.

MR. WEAFER: Or if --

MS. ROY: Oh, you're talking about years beyond this terms.

MR. WEAFER: Beyond you had years where the rate change would have been 4 percent plus to the ratepayers, and you've over-collected from them so you've mitigated and sort of the concept that PBR is sending a signal is masked by the fact that you over-collected.

MS. ROY: No, I don't agree. We've never had any years where those kind of rate increases have been seen in the PBR term. And if you go back to that slide I had earlier, the highest was 1.8 percent, and it's -- so I disagree with that point.

MR. WEAFER: And I recognize what's happened has happened, I'm not debating that. So let me try it another way.

I mean ratepayers, all things being equal would rather not see over-collection. Is there any way of mitigating the over-collection or is this simply a historic anomaly that you had a --

MS. ROY: Well, it's not our -- this is approved by the Commission, Chris. So we've had two annual review applications where we’ve proposed to hold the rates at the prior year levels and record the excess into the deferral accounts, and that was approved by the Commission. So we are just following the approved treatment, and I assume, not speaking for the Commission, that the Commission thought that was the best route forward for those two years.

MR. WEAFER: And I'm more just focussing on the creation of the surplus in the first place. Have there been steps taken to avoid that over-collection from ratepayers?

MS. ROY: Well, I think ratepayers certainly would like to avoid an over-collection, but they are not harmed because we are returning a weighted average cost of capital return on that. And I believe ratepayers -- what we are trying to avoid is volatility so as to hit them with a large rate decrease followed by a large rate increase. And that's why Rick had provided in previous years those undertakings that showed different models about whether it made sense to hold the rates or to decrease them and then see a subsequent rate increase. And the determination made by the Commission was that that flat rate profile was more preferred.

MR. WEAFER: Fair enough. Thank you.

MR. CRAIG: David Craig, Commercial Energy Consumers.

A quick one on your waterfall graph. The O&M 4.607 million. Can you give me a sense of how much of that is volume versus rates; i.e. number of FTE increase versus average pay per FTE?

MR. GOSSELIN: Not while I'm standing here.

MS. ROY: So that is probably --

MR. CRAIG: Do you want to take that as an undertaking.

MS. ROY: No, I'm just going to explain it. It's a formula calculated amount, so it's not based on the actuals. It's the formula. So it's just the prior year formula escalated by the drivers of which one is CPI and one is AWE. So you could possibly break that down that way.

MR. CRAIG: Okay. And is that what the box above means?

MS. ROY: Yes, yes. That shows the formula amount is 4.7 million and then the items that are flow-through outside of the formula are decreasing by 105,000.

MR. GOSSELIN: Yes, precisely.

MR. CRAIG: Okay, and then the depreciation and the financing and return on equity, those are mostly volume versus rate change here that -- still the Mitsu project?

MR. GOSSELIN: Those are driven by rate base particularly and yes, the LMI PSU coming into service has driven the depreciation and earned return up a little bit.

MR. CRAIG: Great, that helps my understanding.

MR. GOSSELIN: Thank you.

THE CHAIRPERSON: Mr. Quail?

MR. QUAIL: I have no questions.

THE CHAIRPERSON: And Ms. Worth?

MS. WORTH: I have no questions.

THE CHAIRPERSON: Staff questions?

MR. GOSSELIN: Thank you.

MR. WOLFE: Jason Wolfe from FortisBC.

Today I'm going to speak on growth capital, but more specifically what some of those drivers of the growth capital are. As we discussed last year, there's a difference between net customers and gross customers. Gross customer additions are those customers that require a service line and/or a main extension and meter to serve them. And that's what drives capital.

Proceeding Time 10:13 a.m. T17

So I'm going to into some detail on where those additions are, what it's looked like over the last number of years, because that is what is driving a lot of the growth capital activity.

So this is a table, or a chart, that I

showed last year. It's a month-by-month view of the number of additions we had, starting in 2014 and going up to 2018. The bottom line there, the purple line, is 2014 and you can see it moves along just under 1,000 additions per month, ramping up in the fall as it normally does.

The trend in these slides is that we've been adding more customers each year. So 2015 we moved up to 16,000 customers; 2017 -- or, sorry, 2016 -- we moved to 17,000; and last year before I spoke we were at -- we were in September in the red line and what you didn't see last year at this presentation was a big uptick in the last three months of the year. That's the big red bump at the end there, where we were adding close to 2500 customers per month. That resulted in an overall number of customer additions of 20,805 new customers.

The majority of those customers were certainly, as you would expect, in the residential space, and this is a combination of primarily new construction. So, new condo developments, new detached homes, new townhouses, et cetera. But it does also represent a smaller number of commercial and, as well, industrial customer growth.

The blue line represents this year and the numbers are up to last Friday. So the blue line there showing in September where it ends just shy of 2,000 additions in September. Overall, year-to-date, in 2018 we are at 15,791 attachments. We still have the last three months of the year, obviously, to add customers and those are generally strong and our expectation is that we will continue to add customers somewhere in the two, to two and a half thousand customers per month for the rest of the year, ending up slightly above where we were last year, last year being just over 20,000. We expect just north of 21,000 this year.

So we've seen continued strong growth. Part of that growth as well this year, the difference between this and last year, is on Vancouver Island, where we're seeing a lot more conversion activity. We're up about 50 percent year-to-date in our conversions on the island, as a result of a number of factors such as the amalgamation, the lower rate there, and a number of marketing and advertising initiatives to get those customers attached.

Next I have just a couple of photos showing our activities and work that's gone on attaching customers. This first slide is something that Ms. Roy referred to a little bit earlier, about sustaining capital being driven by growth activities. This is a directional drill, a main going in in the Fraser

Valley, and it's a result -- or the upgrade is the result of a number of additions that have happened in that general vicinity, as well as overall load growth. So at some point the existing system needs to be reinforced. You have to have more capacity to meet all these customers' needs. And in this case we are doing a directional drill under one of the roads to add that capacity.

This is contrasted with what I would term is a fairly traditional then main installation, where it's done to serve customers. Again in the Fraser Valley, I believe this is for one of the greenhouses out there that was requiring new service.

We had a number of IRs and questions about common trenching, and I'm not the one to speak to the very specific details of this, but I thought I'd just show some pictures of what common trenching looks like.

Proceeding Time 10:17 a.m. T18

The idea behind common trenching is that it's a way in which we can be more efficient in the installation of our service and we go in at the same time as a number of other services. So there are deeper services which are sewers and water mains, and then above that goes gas and electricity, cable, internet, those sort of things, going in on top. So we are in the shallow level of installations.

But from a developer standpoint, what you get is a developer not needing to coordinate a number of different utilities. We can all go in at the same time. You can see from these photos the things like curbs aren't done, grass isn't in, roads aren't paved yet. So that certainly makes it more efficient for the developer and for us to get our installations in. So by doing it in this manner, we are more efficient, we are meeting the customers' needs and we'll monitor this over time. And there are a number of IRs that were on this that we referenced as well.

So when we talk about customer additions, one of the questions that often comes up is that, well, there is a lot of housing development in and around the Lower Mainland, in the Interior and on the Island and of course your numbers are going up because there are more houses being constructed. The rising tide lifts all boats.

One of the studies we perform annually is a market share study where we try to marry existing housing completion data from BC Assessment with our own data from where our meters are to see, did we get a good portion of those customers? What does that market share look like?

So this graph is the latest information we have, and you'll see that it says 2016. We don't get our 2017 market share completed until later this fall as we wait for BC Assessment data. But what you can see from this is that for services that are within 200 metres of a main, our market share has been increasing. So not only are we attaching more customers in a gross sense, but we are also attaching more of each housing development or each new construction project.

Right now the blue line there is -- the blue line are the total number of housing completions, the red is a number that we got, and you can see there it's 83 percent in 2016. So we've seen a solid trend up in our market share, which begs a question of what is driving that activity? What factors are resulting in both the greater demand for our services and also the higher market share?

And so as many of you know, the natural gas rates are lower than other competing alternatives and that's what this slide depicts. This is our residential rates displayed in cents per kilowatt hour so that we can easily compare them. And you can see there that for residential customer they are paying 3.6 cents a kilowatt hour, renewable natural gas at 6 cents, and then the two tiers of BC Hydro.

So certainly this is one factor that

customers are looking at. And by "customers" I mean end-use customers but also developers who are putting in the services for those end-use customers. They are looking at the affordability of energy, their pocket book, and natural gas certainly helps them with that, and as they start to understand rates a little bit more, and granted a lot of customers don’t know rates very well, but they certainly know what their bill looks like at the end of the month, and if it's lower than it was, that's great.

And so having natural gas in their developments and then for those end-use customers certainly helps from an affordability standpoint.

However, that's not all we do. We don't sit and just wait and hope that people understand about affordability and understand that natural gas rates are low. We actually have a number of activities. We undertake trying to help developers understand the value of natural gas and help them get natural gas in their developments.

Proceeding Time 10:21 a.m. T19

As you can imagine, developers, builders, are certainty worried about a number of factors, but many of those factors revolve around the cost to install and the complexity. Anything we can do to reduce their cost and/or reduce the complexity of a build will help them put in our product.

So we work with these developers helping them, because they may not know what to do. Often they will just put in what they did in their last development and move on. However, Ben Nishi who's sitting in the back is one of our Regional Energy Solutions managers and he and his team will actively go out to developers and try to understand what they're looking for from an energy standpoint, and then they search the market to bring solutions to that developer that the developer might not have thought of.

The first example here, that white unit in the lower right-hand corner is a wall furnace. And I actually have one in the back as well, on the break if you want to go look at it. A wall furnace is a natural gas furnace and it is placed on an outside wall and it can heat a condo, a townhouse, a small home, a coach house or a laneway home with just that unit.

Being on the outside wall, the gas line comes in from the outside. The air intake and exhaust also comes in at that same area on the outside wall. And then there's no ducting required. No ducting for the forced air to be moved through the building. From a developer standpoint this means they don't need a mechanical room, so they don't have to pay for the costs of a mechanical room versus living space. It keep their cost down as a result. And then the homeowner gets to have natural gas as a heating source and meet their affordability needs.

The next example is here -- here, again, is to deal with complexity, efficiency and affordability. And what you see is a picture of high-velocity ducting. So in a normal furnace in a basement – you might be aware of this – you walk down and you see a bulkhead and sometimes you hit your head on them.

A bulkhead is put in to drop the ceiling down to allow for ducting to go through a building. Builders don't like that because it costs more money to put a bulkhead in, it drops the ceiling level often, creates different aesthetics in a building, and so as a result they may not put in a furnace.

What we were able to do here and which is much more common is use a high-velocity ducting. So we went out and searched the market, talking to engineers, talking to manufactures to see if there's a solution. And there was. And the solution is high-velocity ducting, which then fits between the ceiling joists and doesn't result in having to have a bulkhead and all those associated costs. Again, meeting the needs of the developer so that they can put in the natural gas products that they want and that their customers want without an impact to their costs or their time.

We're also mindful of what our customers want and -- of course, and also what the policy environment and municipalities, the provincial government is wanting. And one of the things that we have seen that everyone will be quite aware of is the strive and the need to reduce emissions.

So this next technology I'm going to show you is a commercial carbon capture unit. And this unit from a company called CleanO2, what it does is it takes flue gas from a commercial boiler, takes that through a chemical process, removes the carbon dioxide in that process, produces soda ash as a by-product, and also provides a bit of extra heat for preheating, so therefore makes a boiler more efficient.

We are testing this in a number of pilots right now throughout the Lower Mainland to see how this unit words and we've had great response from our customers looking for ways to both increase the energy efficiency of their boiler equipment as well as reducing emissions. And it certainly is neat that the by-product of this is soda ash and soda ash can be used for something like dishwashing detergent. And so this is actually soda ash that's taken from our pilot projects mixed with a few other simple chemicals to make a dishwashing detergent, therefore scrubbing carbon out of the boiler, and the resultant byproduct is soda ash, which can be used in a whole bunch of manufacturing processes.

Proceeding Time 10:26 a.m. T20

So these are a number of the technologies and things that we're looking at, trying to be innovative, meet our customers' needs, that then helps us get gas and/or keep gas into developments and in buildings and in residences, et cetera.

And those are the end of my slides if there are any questions?

MR. WEAFER: Thanks, Jason. You maybe have answered this, just your slides are reminding of DSM initiatives. And I just want to confirm, under spend on DSM initiatives is outside the formula, is that correct?

MR. WOLFE: Yes. Sorry, Diane.

MS. ROY: Yes, that's correct.

MR. WEAFER: Thank you very much.

MR. CRAIG: David Craig. Can you help connect some of this activity to applications that we had previously to change the way that the criteria are established for putting capital in?

MR. WOLFE: Certainly. I spoke mostly in the presentation to the customer perspective and what they are looking for that was driving attachments. But certainly two years ago we had the completion of our system extension, our main extension application. And in that, it lowered the barrier or the cost to connect to customers. And as a result, we certainly are seeing uptake from that process, and that has helped contribute to some of the activity that we see.

MR. CRAIG: And contributed to the customer growth additions?

MR. WOLFE: Absolutely, yes.

MR. CRAIG: Excellent, thank you.

MR. QUAIL: I have no questions.

MS. WORTH: I just have a few questions. I have one about the trenching initiative. Trenching costs are part of base capital. So in your view are there stronger incentives for efficiency in capital spending for base capital as opposed to other capital?

MR. WOLFE: Diane or John?

MS. ROY: Sorry, could you repeat the question?

MS. WORTH: Sure. So we were talking about the common trenching initiative. And I was just -- because those are part of base capital, I was wondering if there are stronger incentives for efficiency in capital spending for base capital as opposed to other capital?

MS. ROY: Right, okay. Well, as it turns out, I mean almost all of our capital is under the formula, so it is considered base capital. The things that come to mind that are outside the formula are things like capital activities in support of natural gas for transportation or biomethane activities. And because those are growing markets and many of those capital activities are fairly new, I'd say generally we might be -- although we are always trying to get things done for the least cost, when you're looking at that kind of market it is more about trying to get it in place, and seeing how it works.

So, it is slightly different, I would say, but almost all of our capital, whether it is contained in a formula, so it would have the same incentive properties, and I think that was one of the goals of the last PBR application was to keep as much in the formula as possible.

MR. WOLFE: And just if I could add from the builder developer standpoint, the incentive, is that we get to put our gas in. Sometimes it could be something as simple as not putting gas service in at the same time as other services, causes an issue for developers, and as a result they may not want gas. So finding ways that we can then meet the developers needs by doing something like common trenching helps us overcome that hurdle.

MS. WORTH: Yeah, that was actually another question that I had, was sort of you have got the innovative technology examples and then you've also got the common trenching. Both seem to be fairly focused towards the developer rather than the individual customer, the residential customer, is that fair to say?

MR. WOLFE: Yeah, the developer is often the -- well, is the individual, the person, the company, that choses that energy source to go in the building. They do that by what their consumers are requesting or their end-use customer is requesting, but ultimately it is up to them. Often they may not choose to put a certain energy source in, because they either don’t feel that the customer wants it, or because of cost reasons.

Proceeding Time 10:31 a.m. T21

So we have to work with developers closely to help them understand the value of gas and then get it in, and overcome the hurdles, whether it be by innovative technology type examples like this, or efficiency through something like common trenching. That overcomes the hurdles that they may see by putting in gas. And therefore they're more likely to put gas in.

MS. WORTH: Okay. During your part of the presentation

you mentioned that there was actually a fairly strong uptick in the number of customers over the Island.
MR. WOLFE: Mm-hmm.
MS. WORTH: Now, is that from the developer's side of things? Or is that existing customers, or existing buildings that are now retrofitting to accommodate gas?
MR. WOLFE: Well, we see both, because there is strong new development going on on the Island, but the increase I talked about, the 50 percent increase, was in conversions. And so those are customers that are converting from primarily oil furnaces over to natural gas. And so they would need a new service and the main sometimes as well.
MS. WORTH: Okay. And then also if we look at your slide, capture rate for residential customers within 200 metres of the main -- I can't see, I'm afraid. I don't have my glasses. I'm getting older.
So, you've talked about sort of the increase. And there is definitely a market increase in the FEI capture there. Would you say that that's primarily due to the increase in customers on the Island? Or is it sort of spread out through the entire province? I'm just kind of wondering, you know, what you can attribute to the Island and what might be other factors?

MR. WOLFE: Just if I can use last year's numbers of additions, we had approximately 20,000 customers additions. 5,000 of those were on the Island, 5,000 were in the Interior, and approximately 10,000 were in the Lower Mainland. So fairly evenly distributed throughout the province.
MS. WORTH: Mm-hmm. Okay. So the Lower Mainland actually was 10,000?
MR. WOLFE: Yes.
MS. WORTH: Okay. And you're expecting a fairly similar distribution this year.
MR. WOLFE: Yes.
MS. WORTH: Although that's sort of a projection at this point.
MR. WOLFE: Yeah, projection. Certainly we have the three busiest months coming up, but we're seeing similar activity. The only change a bit in the activity is the number of conversions on the Island. But we're actually seeing conversion activity in the Lower Mainland, which we haven't experienced before as well.
MS. WORTH: Okay. Thank you, those are my questions.
MR. MILLER: Staff have no questions.
MR. WOLFE: Thank you very much.
THE CHAIRPERSON: Thank you.
Ms. Roy, is it an appropriate time to take

a break?
MS. ROY: Yes.
THE CHAIRPERSON: Great. Let's reconvene at ten to eleven, please.
MR. WOLFE: Thank you.
(PROCEEDINGS ADJOURNED AT 10:34 a.m.)
(PROCEEDINGS RESUMED AT 10:50 a.m.) T22/23
THE CHAIRPERSON: Okay, please go ahead.
MR. CHERNIKHOWSKY: Good morning. My name is Paul Chernikhowsky, and as alluded to by Diane earlier, I'm going to start out with a bit of a discussion on our sustainment capital. I'm not going to go through the topic in exhaustive detail. I think Section 3 of Appendix C-4 and the associated IRs cover the area quite well, but I do just want to reiterate some of the primary categories shown in the updated Table C4-4 of that appendix that are driving our capital variance above formula.
So in that table we show our cumulative annual variance over the period of PBR when compared to formula is about 69 million, in that table. Breaking that down, there's three primary contributors to that cumulative variance. About half, 34 million, are impacts from the PBR decision itself, and the notes 1 and 2 in the table list them, and I just summarize them.

Basically the reduction of the base sustainment capital in the decision for the inclusion of the Vancouver Island system within the FEI system. And then there's the lower growth factor for customer additions. So in the decision the growth factor was 50 percent instead of 100 percent for new customers.

The other half of the cumulative variance is made up of two. One is unanticipated projects. So these are primarily increased in-line inspection activities, and that represents another 13 million, approximately. And then as well in a similar vein, unanticipated system improvements and new stations to supply gas to new customers is another 21.6 million.

And Jason talked about this a bit earlier, but just to reiterate, so these are growth projects that are driven and occur through the system, but they are driven by increased low as opposed to an asset condition issue. And examples of these would be system upgrades that were necessary to supply increased demand in the Whistler and Campbell River areas.

Again, they key message here is that we are not deferring necessary essential work simply to stay within formula. And another thing that I would characterize it as, if you look at these three main areas, in the absence of those pressures within the

PBR mechanism, excluding them our variance cumulative over the term would have been manageable, I would say, within the deadband and within the ability to control projects that are flexible in the capital program. So these represent the main challenges.

Proceeding Time 10:53 a.m. T24

So I'm going to switch gears now instead and talk about our approach to integrity management of our gas system at FortisBC. And I'd like to talk about some of the projects that we're doing as part of our sustainment activities, and also some of our upcoming major projects, which will be the subject of CPCN applications.

So first of all the goal is very straightforward. Our policy is to strive for zero incidents of significant consequences. And those consequences could be safety-related. So a serious injury or worse to any person, whether employees, contractors, customers or the public; irreversible long-term harm to the environment; or service disruption. So, wide-scale outages that affect large numbers of customers.

And how do we achieve that goal of zero incidents? I like to think of it as a three-legged stool with three fundamental underpinning aspects. We have management systems that we use to manage our system integrity. So, for example, as required by code, we have a long-running and robust integrity management program.

There's our people. And here I'm referring to our highly trained professional and trade staff that actually design and operate the system on a daily basis.

And there's the specific activities that we do. So for example surveying for leaks, undertaking planned and unplanned maintenance. Ensuring adequate ground cover over our pipelines. And many more.

But the activity I'd like to focus on today is our in-line inspection program for our gas transmission system, and that's what I'll get into next.

So let's talk about in-line inspection, also known as, colloquially, "pig and dig". So, we've been running the in-line inspection, ILI smart tools, since the late 1980s. And so for example we have a photo on the left here, and this is a crew in, I believe, our Penticton station, getting ready to launch a pig into the pipeline, off to the right.

And essentially what happens is, the pig — smart tool — travels along inside the pipe and it records an electromagnetic signature of the pipeline wall. And then we can then remove the pig, take the data out of it and analyze it looking for anomalies. And we're looking for things like metal loss, for example corrosion, or other features such as gouges in the metal or dents in the pipe wall.

So we run these tools on a five to seven-year interval and it's based on a pipeline-specific assessment. And it's important to note, though, the original pipeline system constructed by FEI and FEVI -- or FEI, was not generally designed for in-line inspection. We're continually looking to increase our capability to run these tools through retrofits to the system. And in the industry, ILI is still considered the best tool to assess pipeline condition.

For reference, we spend currently around $3 to $8 million a year on in-line inspection runs.

Then once an ILI run has found an anomaly, needing further confirmation, the next step is an integrity dig. And I have a photo on the right here showing one that took place -- I believe this is in the Surrey area, Lower Mainland. Essentially what happens is, we dig down, expose the pipe, remove the coating, and look more closely at the actual metal over the pipeline. So we use these digs to validate the ILI data, to assess if there is possible corrosion growth, and looking at trends in it over time. And then if necessary, conducting any site-specific repairs. And we spend about $2 million a year on integrity digs.

And just for reference, you can see in this picture, given the location, the disruption that it can cause to both customers and the public as well. So we try to avoid them, but at the same sometimes they are necessary.

Proceeding Time 10:58 a.m. T25

So, as mentioned, we currently have the ability to run in-line inspection tools through some, but not all, of our transmission system. And so what we've already talked about today, our current in-line inspection methods and technology, fundamentally again that technology is about looking for metal loss or deformation in our large diameter pipelines.

Now, I'm going to talk about two upcoming CPCNs. The first one is our upcoming application for our so-called in-line gas upgrades project, and this one is about the ability to add or -- to add the ability to inspect small diameter pipelines. Primarily these are what we refer to as laterals, so taps off the Westcoast Transmission line in the interior that we currently can't run ILI on. And then the second one is to provide an introduction to our so-called transmission integrity management capabilities project. And then the associated deferral account request.

That project is about enhancing our ability to detect an emerging threat knows as stress corrosion cracking. But the key point here is that all three activities are complementary. One doesn't replace the other. And the long-term goal is to get us to that centre spot where we are in the best position to assess and monitor the condition of our transmission pipelines using available technology.

So the first project up, as I referred to, is our Inland Gas upgrades. For many years we've been able to inspect many of our pipelines in the Lower Mainland and our larger pipelines in the Interior. However, we do have a substantial amount, it's about 400 kilometres of smaller diameter but high-pressure pipelines in the Interior that we're not able to inspect. And why is that?

Well, first, the pipelines were not designed for in-line inspection as I mentioned earlier. Some of them were installed over 50 years ago, and so you can image at the time when the technology didn't exist, they were designed with blockages. So for example, tight bends in the pipeline, small diameter valves, pipe wall thickness changes. And all those prevent the ability of the tool to run from one end of the pipeline to the other.

And secondly, until recently, the tool simply didn't exist, so you couldn't -- there were no vendors that offered a tool that would be able to inspect a pipeline of that diameter. Vendors are now offering tools to inspect the small diameter pipes, and these generally are in the six to eight inch range, and our assessment is that the technology is mature and it's well demonstrated at other Canadian pipeline operators, and so we feel it's appropriate and prudent to take advantage of this newly proven technology -- sorry, now proven technology.

That said, we are also considering more cost effective solutions, and I list them here. So for example, for short pipes it might make more sense, actually, to simply replace the pipe with newer and stronger pipe. You can imagine for a short, several hundred metre stretch, installing the equipment to launch and receive the pigs at each end is fairly expensive, so it's actually easier in some cases just to replace it.

And then the other alternative where it's available to us is to reduce the operating pressure such that any pipeline failures that do occur are not by failure by rupture but instead by leak which can be managed.

So we intend to file a CPCN later this year in which we'll propose our various solutions, and the project plan, and I just wanted to show that we have a map here and it shows where the work will occur in the area of our service territory, and so indigenous and stakeholder consultation will be critical to the success of the project.

So before we talk about our last and next meter project, I just want to introduce some terminology.

Proceeding Time 11:02 a.m. T26

And for this one we refer to something called EMAT or electro mechanical acoustic transducer. And that is a type of pig in-line inspection tool that is relatively recently developed. It's a highly sophisticated tool and essentially what it does is it uses electromagnetic waves to make the pipeline wall vibrate, and then it detects the soundwaves, ultrasonic soundwaves coming back from it. And it can be used to detect the condition of the pipeline wall.

What it's looking for is a phenomenon called SCC or stress corrosion cracking. That is a type of corrosion that can occur in certain pipelines and it occurs lengthwise in the pipeline wall and it weakens the strength of the metal. And the justification for our project will be to allow us to detect potential SCC in our pipeline system.

Now, SCC generally needs three conditions to occur. It needs material that's susceptible to it, presence of certain ground soil conditions, and then steel operated at high stresses or high pressures. It is a phenomenon that cannot be detected through our conventional ILI tools that currently FEI runs. And if left undetected it can result in a pipeline failure, a rupture, due to excessive crack formation.

Now, while we haven’t seen failures due to SCC in our system, other operators in Canada have and we have found evidence of SCC in our pipelines as well. SCC is a time dependant threat, and so older pipelines are at a higher risk.

And you can see in the figure on the left it shows over half of our transmission system is more than 40 years old. For interest, the original build prior to 1970 was the original FEI system, and then the big add in the 1990s was the Vancouver Island system, when that was constructed. There was the Southern Crossing pipeline in the 2000s, and then the recently completed Coastal Transmission System projects in the 2010s.

In terms of the acceptance of the tools, the graph on the right shows the significant ramp up of EMAT tool usage and other CEPA operators. And CEPA is the Canadian Energy Pipelines Association of which

FortisBC is a member, and so we share information to see what other companies are doing. The bars are the actual numbers and then I had Excel calculate and add a trend line so you can see the fairly significant increase in recent years, which we expect to continue.

So as mentioned, SCC is currently undetectable using current tools, and so this project is intended to retrofit about 1400 kilometres of pipeline to allow us to run these new EMAT tools to detect any SCC. These are larger diameter pipelines, typically 12 inches and greater. And, again, the reason for that is -- why not smaller ones? The tools don't exist.

Consistent with other similar major projects we are currently seeking approval of a two phase deferral account to collect the development costs associated with the preliminary engineering and risk assessment. So as discussed in the application, we're seeking approval to create a new deferral account to collect the development preliminary investigative costs.

Phase one is intended to conduct what's referred to as a quantitative risk assessment using data that we previously collected about our pipeline system and incidentally that data was collected through our previously approved GAR project, gas assets records project, which was funded through a deferral account. This phase will essentially produce a list prioritised by segment of pipelines which require more scrutiny from an SCC perspective.

Proceeding Time 11:06 a.m. T27

Once we have that prioritized list, in phase 2 we then intend to begin the preliminary engineering to develop the scopes, estimates and schedules for the modifications necessary to allow us to run these EMAT tools to address the SCC risks.

And the reason we are seeking approval of deferral to collect costs for both phases at this time, is that we intend to begin that work in the first half of 2019. Given the schedule shown here, that would then allow us to start construction in roughly 2022.

So, of course the question may be asked, Why now? Why are we starting this work? Well, we have it first of all a direction from the B.C. Oil and Gas Commission to development a per-segment QRA, quantitative risk assessment for our entire pipeline system. And second, as mentioned, the tools are now well proven and other operators are embracing the technology. So, given those facts and the age of our pipeline system, we feel that now is the right time to assess and mitigate this potential risk.

That is the conclusion of my slides.
MR. WEAFER: Chris Weafer from Commercial Energy Consumers.
Thanks, Paul. I'm going to focus on the CPCNs. And as I understand, the TIMC project, that's a billion dollar project over time, is that fair, rough estimate as to what is going to unfold in the implementation if that is approved?
MR. CHERNIKHOWSKY: In an IR we did respond that for business planning purposes we have identified some costs in future years of approximately 250 million a year for three years. It is very early at this time, and those are at best conceptual numbers, based again primarily on the length of pipeline that needs to be retrofitted and very high level estimates which still need to be refined.
MR. WEAFER: Was that -- I've been doing this a long time, and I've never come across a direction from the Oil and Gas Commission resulting in a potential billion dollar expenditure by a utility regulated by this Commission. Was there any discussion with the Oil and Gas Commission about what they were directing to be done, and what the potential cost was going to be to the utility?
MR. CHERNIKHOWSKY: So, first of all, to clarify, the B.C. Oil and Gas Commission, their direction was for

FortisBC to conduct a quantitative risk assessment. And what that is is basically they want to know what the risk of failure and the consequences of failure of any given pipeline segment are. They don't specify to the operator or the utility any action that has to be taken. That decision is up to the operator still. Now, our decision is that the best way to respond to those risk especially in this area, SCC is to be able to run EMAT tools.

MR. WEAFER: And I look to the IR response to 21.6.1 to BCUC Staff IR. Could you do the quantitative risk assessment as a CPCN project in of itself, without moving on to the CPCN in terms of the implementation of your solution?

MR. CHERNIKHOWSKY: They are stand-alone phases, yes. But fundamentally again we are aware of the risk. It is not a question of whether the work needs to happen. All the QRA is going to identify the priority of where the work needs to happen. And so we want to still undertake that work as soon as possible.

MR. WEAFER: And so just again, just trying to deal with assessing the risks. Is it feasible from a regulatory process standpoint to do what the Oil and Gas Commission has directed, to bring that to the Commission in terms of how realistic the risks are, and then deal with what the solutions are? I mean, you can respond to the Oil and Gas Commission direction without moving down and proposing the next phase in terms of this massive investment.

Proceeding Time 11:11 a.m. T28

MR. CHERNIKHOWSKY: Correct. But I don't think we should necessarily get distracted by the QRA. That is a supporting piece of documentation that we will use if we're going to undertake this project, or when we undertake this project, I should say.

But it's not necessary for it. The bigger issue for us is that the risk that we're facing here, SCC, stress corrosion cracking, is a time-dependent threat. And we have seen evidence of it in our system already. So we don't want to delay any longer than necessary to undertake that work. And so that's why we're essentially combining the two activities together.

MR. WEAFER: So you would have been doing this irrespective of the order from the Oil and Gas Commission?

MR. CHERNIKHOWSKY: That is correct.

MR. WEAFER: Just last on this quantitative risk assessment and trying to put some information before the Commission and stakeholders, what's the timeline to complete that?

MR. CHERNIKHOWSKY: So, we have engaged an expert consultant to assist us in that. Our initial first pass produced by them will be later this year, and then we expect to have the majority of our pipeline system assessed in Q1/Q2 of 2019.

MR. WEAFER: Would the company be open to a process around reviewing that quantitative risk assessment with the Commission, in terms of getting a base for step 2? And whether step 2 is the prudent course.

MR. CHERNIKHOWSKY: I think the bigger issue is, a quantitative risk assessment by its nature, of course, is highly technical. And I think really to tell the more fulsome story, it would be necessary to combine it with the work that's happening otherwise. So, I wouldn't say that we're resistant to it, but I'm not sure how useful it will be in absence of the other information.

MR. WEAFER: This is obviously relatively new information to the Commission and to stakeholders. So having a more -- providing a more substantive justification for that investment could be made, do you think that might be helpful to those who are trying to understand this potential investment?

MR. CHERNIKHOWSKY: Internally we have actually considered perhaps having a workshop somewhere along the way to discuss what we're working on, and the impacts to customers, and to our system. And so we could look at something like that, yes.

MR. WEAFER: We would certainly support that.

And can I go to your graph and as I said, I was doing this a long time, which means my eyes aren't as good as they used to be, and this is the EMAT tool adoption that other CEPA operators. Can you tell me what the information is on the X and Y?

MR. CHERNIKHOWSKY: Ah, yes. Sorry. The legend appears to be lost there. So on the left side, we have -- the Y axis is number of kilometres. So it's running from zero to 4500 kilometres. And then on the bottom is from years 2002 to 2016. That's the most current data that we have.

MR. WEAFER: Are you aware of any utility that's invested a billion dollars in this process? And that table of information.

MR. CHERNIKHOWSKY: I would say that to our knowledge mostly all other pipeline operators in Canada are employing EMAT tools in their operations. So for example, the Enbridges, the TransCanadas, are already using these tools. So they have undertaken the investments necessary to already run them.

And the analogy that I use is, if you have ten people standing in a row and nine of them take a step forward, effectively you've taken a step back. So we want to ensure that we're consistent with other

pipeline operators in Canada.
MR. WEAFER: So the questions was sort of quantitatively the amount of investment. You've looked at other -- several utilities, and these are -- this is the nature of the investment that they've been making, a quarter million a year to put in the technology?
MR. CHERNIKHOWSKY: It depends on the operator. The other thing to keep in mind as well is, other operators have a different system from FortisBC. Other operators tend to have point-to-point pipelines that may be very long. But there's no stops along the way.

Proceeding Time 11:16 a.m. T29

So it's actually easier to retrofit pipelines like that to run these tools, whereas the FortisBC system stops at a number of stations throughout the Lower Mainland, for example, and just running through the various areas there's a lot of bends in its nature. They are not straight pipelines that are point-to-point. So the cost to retrofit tend to be a lot higher.
MR. WEAFER: Right. The cost per kilometre is going to be a lot higher for Fortis than it is for the ones you are comparing Fortis to in the graph. Is that fair?
MR. CHERNIKHOWSKY: That's correct.
MR. WEAFER: Well, this isn't the workshop on this

topic. I'm just going to convey a significant level of concern about it and the proposed investment in it, and we'll deal with submissions around potential process to help with that.

So thank you for your comments. With that I'll let David or Janet if they have any questions. Thank you.

MS. RHODES: So just one quick question on the same graph. So if FortisBC were to add its kilometres into this graph, how many kilometres would you be adding? Around 4,000 I think around here.

MR. CHERNIKHOWSKY: We would be adding 1400 kilometres approximately.

MS. RHODES: Thank you.

MR. ANDREWS: I have what I think is a follow-up question about the same graph or the same concept. And you were using the example of ten people of whom nine step forward. How does FortisBC compare to other gas distribution utilities in Canada, or in the United States for that matter, in relation to the adoption of this EMAT technology? Again, distinct from the long-distance pipelines.

MR. CHERNIKHOWSKY: So just to reiterate, I would say that pretty much every pipeline operator in Canada already employs these tools. Pacific Northern Gas, the other transmission line operator in British

Columbia, a distribution utility has run EMAT tools in their system. At this point FortisBC has not run any and does not have pipelines able to run them. And so we feel that we are lagging compared to the rest of the industry at this time.

MR. ANDREWS: In other jurisdictions, or PNG in B.C., are these investments in the use of this technology driven by regulators?

MR. CHERNIKHOWSKY: They are partly driven by regulators and experienced with past failure incidents. They are also being driven by operators that feel the work is necessary as a prudent operator to ensure the safety of the system.

MR. ANDREWS: And what would you say is the reason that Fortis is left behind, is the only one that hasn't begun to use this type of technology?

MR. CHERNIKHOWSKY: Again, it primarily is due to the configuration of the FortisBC system. Where other utilities typically have long point-to-point pipelines, our system is more of what we refer to as a high pressure distribution system. And so one of the issues, for example, is that these new tools have to run at a certain flow rate through pipelines. And in the case of a transmission operator where you may have twined pipelines, you can control individually the flow of whether it's oil or gas through that pipeline and you can control the speed of the tool such that it gives you accurate data.

The FortisBC system is a bit different because our transmission lines are feeding our end-use customers and so the flow rates to our customer are directly related to our customer demand at any given time. If our customers aren't demanding gas, the gas doesn't flow through the pipelines. Conversely, if they are demanding a lot of energy at a given time, the flow rates are now too high. And these tools have to run at a very specific speed through the pipeline, otherwise they don't collect good data.

So effectively it was easier for other operators that have the ability to control the flow rate through their pipeline system compared to FortisBC. For us, the ability to control flow rate is something that we would have to do in some cases by twinning pipelines.

Proceeding Time 11:20 a.m. T30

MR. ANDREWS: In terms of the regulatory authority, and the Utilities Commission, and the Oil and Gas Commission, you mentioned that the Oil and Gas Commission has issued a direction which you are characterizing as not necessarily crucial in driving this forward. Do you anticipate that the Oil and Gas Commission will follow up that direction, and would it be normal for the Oil and Gas Commission to be looking at directing the company to implement solutions that come out of the research that they've now ordered?

MR. CHERNIKHOWSKY: So again, the Oil and Gas Commission generally don’t specify the specific activities that operators undertake. We have been in discussion with the B.C. Oil and Gas Commission. They are aware of this preliminary work that we're undertaking, and our proposed plans for both of our CPCN projects. And I would say they are supportive of them. So, as long as we continue on down that path, I don’t expect to hear much from the Oil and Gas Commission.

MR. ANDREWS: What was the impetus that led to the Oil and Gas Commission issuing this direction?

MR. CHERNIKHOWSKY: It was a finding through an audit of our integrity management program. So, every three years the B.C. Oil and Gas Commission audit operators to investigate the efficacy of their operators integrity management programs. One of the findings there is that although FortisBC, we've identified all the activities that we use to manage our pipelines and we feel that that covered the risks adequately, they wanted to know, again, in a numeric sense, how risky each pipeline segment was.

From our perspective, because we treat every pipeline as being important, that need for that information at that time wasn't necessary. That said, it is helpful for this endeavor, because when you're looking at retro fitting a large amount of pipeline, having the ability to prioritize pipeline segments is useful.

MR. ANDREWS: What is the consequence of a corrosion stress -- a stress corrosion crack? I mean, I am asking you to fill in the blank. Is this a catastrophic rupture of a pipeline? Or how would it manifest itself?

MR. CHERNIKHOWSKY: For high pressure pipelines typically it would be a seam rupture along the length of the pipeline, and yes, you would have an uncontrolled release of gas at high volumes.

MR. ANDREWS: Those are my questions, thank you.

MR. QUAIL: I have no questions, Mr. Chair.

MS. WORTH: No questions.

MS. WALSH: I have a few follow-up questions about the TIMC project, and particularly the deferral account. You referenced actually as well in slide 27 the gas assets record project and its connection to this project.

I was just wondering, first of all, is the data gathered through the gas assets record project being utilized for this project? And if so, was that coincidental? Or were the projects somehow connected?

MR. CHERNIKHOWSKY: So, the projects are directly complimentary. So the gas assets records project, what that was about, for those that weren't involved in the original hearing, essentially it was to go out and collect all of the information on our system that we have, and you can imagine as effectively an amalgamation of a number of different utilities over many decades. Information was stored in offices throughout the province. And so, the intent of this project was to collect all that information, digitize it, attribute it, and then store it into an electronic database system. And so we've now done that.

Proceeding Time 11:25 a.m. T31

However, there was no analysis of that data that went on. It was simply a categorization of what the type of data was, who created it, what asset it's related to. Now we're able to take advantage of all that data, however, and analyze it and use that in that quantitative risk assessment.

MS. WALSH: Thank you. Could you confirm or possibly provide an undertaking, I just have a few questions related to the gas assets record project, specifically the first one being, it expects to be complete at the end of 2018.

MR. CHERNIKHOWSKY: I would have to take that under -- subject to check, but I believe it was intended to be

completed at the end of -- or within 2019. But within the originally approved budget.
MS. WALSH: Okay. Which is essentially part of my second question, which was, I believe subject to check from previous annual reviews that the forecast or expected costs for that project was about 7.8 million. So, I'm just wondering if you could provide information on how closely that project is tracking to the original forecast.
MR. CHERNIKHOWSKY: We can confirm that, but I can say right now that we do intend to complete it as per the original scheduled budget.
MS. WALSH: Okay. And then you mentioned in response to BCUC IR 21.1 that FEI is leveraging internal resources from its gas asset records project team to supplement the consultant resources for the TIMC project. I'm just wondering if that -- the result of using some of those resources had had any impact on the gas asset records project timeline, or completion?
MR. CHERNIKHOWSKY: It hasn't had any impact. Rather it's benefited from it, as in the individuals that were no longer required for that project now become free, and because they're familiar with the systems and the data that's being produced, it is well suited for them now to transition over into the analysis side.

MS. WALSH: Okay, thank you. Then this question is more related specifically to the proposed or requested deferral account for the TIMC project development costs. So, in the application, in the table, the Table 12.1 -- or 12-1, you've provided the Phase 1 and Phase 2 development cost spending. And then in Table 12-2, which is where you describe the deferral account request in the context of the BCUC's deferral account guidelines, you had stated that in the absence of the requested deferral account the development costs would be a combination of O&M and capital expenses outside of the formula.

This topic was also pursued in BCUC IRs as well. I'm just wondering, in an undertaking, if it would be possible to provide the estimated rate impact by year under a scenario where the Phase 1 and Phase 2 development costs were not included in approved deferral accounts.

Information Request

MR. CHERNIKHOWSKY: Yes, we can do that.

MS. WALSH: Thank you. And I just have a few questions as well about the Whistler IP extension project. Would there be -- would you be the person to ask those questions to?

MR. CHERNIKHOWSKY: Sure.

MS. WALSH: Okay. Okay, so if you could -- I'll be referring to BCUC IR 8.11.

MR. CHERNIKHOWSKY: I'm not sure if I have the IR, but you ask the questions and I'll see.

MS. WALSH: Okay. We can forge on ahead.

MR. CHERNIKHOWSKY: Sure.

MS. WALSH: Okay. So, in response to BCUC IR 8.11, FEI described the Whistler IP extension project. And they've said since the filing of the application the 2018 estimated cost for this project has increased 10.3 million. I just wanted to clarify if the 10.3 million is the forecast total cost of the project.

MR. CHERNIKHOWSKY: That is correct, yes. It's the total cost to completion.

MS. WALSH: Okay. And then in the response to BCUC IR 8.11, you describe that the system upgrade is driven by significant capacity shortfall in Whistler that cannot be resolved by typical infill system improvements. And you also state that there were delays in identifying a route that is acceptable to all stakeholders.

Proceeding Time 11:30 a.m. T32

Is it possible to provide an update on, first off, to sort of explain a bit more detail about the issues with the stakeholders and any further progress on that?

MR. CHERNIKHOWKSY: Fundamentally the issue was the original project proposal was that the IP pipeline was to be routed along Highway 99 into the Whistler area to a new gate station constructed in the north end of Whistler. And in our discussions with the Ministry of Transport they had concerns having a pipeline within their road right of way.

The existing pipeline is routed in a portion of it. However, for whatever reason, the Ministry felt that they did not want more pipeline than necessary located in that right of way. So FortisBC, we then undertook discussions with the City of Whistler instead, the municipality, and came to an agreement where we could actually route our pipeline through the municipal roadways.

And in some ways that actually is advantageous because it actually allows for less disruptive construction. We don't have to shut down the highway. But the construction techniques themselves in any event in the Whistler area are highly complicated. As you can imagine, Whistler is primarily rock, and so a lot of the pipeline there is excavation through rock. There is also complications associated with railway crossings, highway crossings as well.

And then in terms of the project cost estimate itself, I would say that when we originally estimated the project, it was based on conventional practices at that time and our knowledge of previous projects. The estimate that we've submitted in the application and the update is based on actual contract costs. So at the time of the original estimate, we had not even issued a tender, whereas now we have confirmed costs that were issued through a competitive tender to complete this work.

MS. WALSH: And just following up on the new estimated cost of 10.3 million, would it be possible in an undertaking to provide a breakdown of the actual forecast costs by year for the project?

MS. ROY: I believe all the costs are in 2018.

MR. CHERNIKHOWSKY: Yes, the project will be completed in 2018.

MS. WALSH: Okay, so -- but you would be able to provide a breakdown of the costs.

MR. CHERNIKHOWSKY: Into high-level categories, yes.

Information Request

MS. WALSH: Thank you. And then just understanding that FEI's threshold for spending or materiality threshold was increased under the, I think it was the 2015 decision to 15 million, so this would fall below, but just in consideration of some of the consultation issues that FEI was having and the increase in costs, did FEI consider filing this application separately from the annual review process?

MR. CHERNIKHOWSKY: I would say fundamentally because the project did not exceed the major projects capital threshold, at this time, no, we did not.

MS. WALSH: Thank you.

THE CHAIRPERSON: All right. Thanks very much for that. Who is your next presenter?

MR. WONG: So I'm going to conclude the formal part of the presentations with a quick overview of the SQI results, specifically 2017 full-year results and the August 2018 year-to-date results.

So this format you've seen in the past and it includes the 2017 annual results. This is consistent with a decision in Order G-44-16 where the Commission determined it was appropriate to review service quality in the following years' annual review.

There is specific discussion of this discussion on page 137 of the application.

Proceeding Time 11:34 a.m. T33

So just in terms of an overview, the top part are the ones with the benchmarks. There's nine of them in total. If you see the -- refer to the 2017 column, all nine of them were benchmarks, either have met or exceeded the benchmarks. And for the four SQIs that are considered informational only they are at the bottom. The results of 2017 are generally consistent with that of the recent years' results.

And then in the 2018 column the results are consistent with 2017, except perhaps with a slight variation for meter reading accuracy. Last year is marginally a little lower than the benchmark. I'll have that specific number in the next slide.

So in terms of the, what we call responsiveness to customer needs service qualities there's five of them in total with benchmarks. And as you can see for 2017 they've all met or exceeded the benchmark. And then for 2018 year-to-date the only one, as I said earlier, that's slightly a little bit lower than the benchmark is the meter reading, but that's just 0.1 percent lower than the benchmark.

And just as a note, the 2018 year-to-date was also -- this is the first time you're probably seeing them. What we filed in the application was the June year-to-date. As you can see when you refer to the application the results are fairly similar.

And then for the remaining SQIs, the safety and reliability, as you can see they all -- the ones with a benchmark all have met or exceeded the benchmarks. And then, again, also for the informational indicators at the bottom half of the diagram, the results are generally consistent with that in the past.

So when we look at it overall in terms of the PBR to date, so from 2014 to 2017 full-year and also 2018 August year-to-date, the SQI performance benchmarks have all been above the threshold at least.

That's it in terms of the results. I can take any questions on SQIs or perhaps we can just have a general discussion about other questions.

THE CHAIRPERSON: Do we have any questions specific to the SQIs?

MR. ANDREWS: I have some questions about the informational measure to do with the company's greenhouse gas emissions. And I'll be referring to Exhibit B-4, the company's response BCSEA IR 7.1. To get ourselves oriented, on the first page of the response there are figures for GHG emissions from 2009 to 2013, and then the table continues over the page 2014 to 2017. Do you see that?

MR. WONG: Yes.

MR. ANDREWS: And lower -- in the middle of the page, page 15, there's a block of GHG emission numbers for 2009 to 2013 that are restated, and those are using -- they're back estimated using the same GHG emission factor as is shown in the 2014 to 2017 above. Is that -- are we on the same --

MR. WONG: Yeah, I'm on page 15.

MR. ANDREWS: Yeah. So my question concerns the overall trend and the factors related to it. So you look at the 2009 down to 2013, it's roughly declining and likewise 2014. However, in 2017 there appears to be an increase.

Proceeding Time 11:38 a.m. T34

And my question is, what is the reason for an increase in 2017? Is that a deviation from an overall trend, or is that just an indication of the variability that is normal from year to year?

MS. ROY: I think we'll have to take an undertaking on that one, Bill.

Information Request

MR. ANDREWS: Yes.

MS. ROY: We don't have anybody here to answer that question.

MR. ANDREWS: Thank you. If you would respond to that by undertaking.

MR. WONG: We can do that.

MR. ANDREWS: That would be very helpful. Thank you. Thank you.

MR. QUAIL: I'm going to shock everybody by saying something nice. And that is, want to acknowledge the attention of the company to employee safety. Note the improvement in the already low frequency rate, further improvement comparing the June year-to-date to August, decreasing from 2.8 to 2.81. So, again, pick yourselves up from the floor. We're not saying anything other than this is an item where there's an acknowledgement of improvement that you've made.

MR. WONG: Well, thank you, Jim.

MR. ANDREWS: If I may, I have a question that's not specifically on SQI.

THE CHAIRPERSON: In that case, then, if I can ask that we -- we can move to the open question section.

MR. ANDREWS: Sure.

THE CHAIRPERSON: And we will just take them in sequence, starting with Mr. Weafer. Oh, in that case, yes, Mr. Andrews. It's your turn again.

MR. ANDREWS: Okay. This topic concerns DSM spending and savings. I think I'll refer to Exhibit B-4 again, the company's response to BCSEA IR, and this time it's 2.3. There's a table provided on page 3 of the response that shows DSM spending by program area. And the first set of columns is the span, and the second set of columns is the savings in gigajoules.

The numbers may be a little hard to read, but the question I have is to do with the difference between the 2018 projected and the 2018 plan. And for some of them, for some of the program areas there isn't a large difference. However, for example, for the industrial 2018 projected figures, 1,624, which would be 1.6 million, compared to a 2.9 million spend, and then the next line, for low income the projected spend is 2.9 approximately, compared to a plan of 3.4 or 5 million.

I guess first I'll stop there and ask, what is the explanation for why those particular program areas appear to be substantially below the 2018 planned figure?

MR. WOLFE: Jason Wolfe for FortisBC. I can speak to the industrial. The industrial -- one of the challenges with industrial, just timing. So we worked the industrial customers to encourage them to partake in our CNM or DSM programs. We will sign them up for a specific program and then it's often an issue of timing of when they get that work done, and when they can do that within their industrial processes.

So our expectation was that we had a higher amount in the plan and what we've seen with some of these industrial customers while they are planning to do the work, it just hasn't happened yet this year because of other reasons within their own business processes.

Proceeding Time 11:43 a.m. T35

MR. ANDREWS: And do you feel you have enough flexibility to move spending allocated for the industrial program area to 2019 if that corresponds to the plans that the customers have developed?

MR. WOLFE: I think we do.
MR. ANDREWS: And does it follow that you're planning or anticipating spending more on the industrial area in 2019 than you otherwise would have planned?
MR. WOLFE: This is subject to check. I probably would have to check the exact specifics of what that plan is for 2019. Certainly we have seen a little slower uptake on those programs in 2018 due to the timing and the issues that the industrial customers have in executing, but right now we certainly have projects that we are anticipating for the rest of this year and next year, the timing of which I'm not a hundred percent sure on, I'd have to check what that dollar number would be.

Information Request

MR. ANDREWS: If you wouldn’t mind, that would be helpful.
MS. ROY: And I'm sorry, Bill, just to confirm, would you still like a follow-up as well on a low income decrease in 2018?
MR. ANDREWS: Yes, please.
MS. ROY: As well as what the plans are for 2019 for industrial? Is that correct?
MR. ANDREWS: Yes, and we'll get to low income as well in a sec.

Information Request

MS. ROY: Okay.
MR. ANDREWS: But while we're on industrial, can you discuss the relationship, if any, between the growth in demand from the industrial customer class and the DSM spending and savings?
MR. WOLFE: The growth and demand is the result of a couple of factors. One is the addition of new customers that are using natural gas for their processes and we've seen some growth in the agricultural area, specifically greenhouses has been driving some of that growth. The other growth that we've seen is a fuel-switching -- as a result of fuel switching, so in our cement -- some of our cement customers have been moving from using coal for their main source of energy over to natural gas. As a result you see an increase in volume there.
Both of those reasons are distinct and separate from our DSM initiatives with respect to those customers.
MR. ANDREWS: Why would the cement producers be switching from coal to natural gas?
MR. WOLFE: Two reasons: Price and emissions.
MR. ANDREWS: If I could direct you to the low income line on the savings side of it, while the spend for 2018 projected is lower than the 2018 plan, the savings are quite a bit higher in 2018 projected than

2018 planned. Is there a reason for that? And can that be expected to continue in 2019?

MR. WOLFE: I think we'd have to take an undertaking for that. I don't have that information handy.

Information Request

MR. ANDREWS: Thank you. So I think if I could summarize it, it would be essentially to provide the 2019 version of this table.

MR. WOLFE: The whole table or the industrial and the low income?

MR. ANDREWS: I think it would be helpful to have the whole table to put them in context, but if there's a substantial amount of extra work involved, then no.

MS. ROY: No, the table would have been filed in our 2019-22 DSM application so it's a fairly simple matter to just provide that table.

MR. ANDREWS: In that case that's probably the easiest way to do it them. Thank you. Those are my questions.

Proceeding Time 11:48 a.m. T36

MS. WORTH: So I have a question about the Table 1-4 in Exhibit B-2. Not necessarily something you have to refer to, but it's the actual CapEx, formula CapEx to meet to the year 2014 to 2018 projected. With the cumulative variance over the five years of $150 million.

And I'm going to ask, in FEI's opinion, and given these large and persistent overages, does it make sense for FEI to have a formulaic CapEx amount should there be a future PBR plan in the near future?

MS. ROY: We feel that there is still value in having a formula approach. It does provide a lot of flexibility in how we prioritize projects year to year, and we have been able to find some savings by looking at that capital planning on a longer-term basis. I'm sure Paul or others could attest to that. And we've talked about it at other annual reviews as well.

So I think there's still value in having a formula approach, and we do believe that we can develop a formula approach that is going to work for the next PBR plan. And we've learned a lot from this plan, at what doesn't work. And so we're trying to take those learnings and bring it forward to the next plan that we would propose. Of course, it will be up to the Commission to decide.

MS. WORTH: Okay. And when you say "work" you mean one that wouldn't actually result in these types of persistent overages?

MS. ROY: Yeah, well, I think you're still going to -- you're never going to be able to be exactly on the formula. But you know, our goal would be to have a formula where we could actually demonstrate some savings against the formula by having that kind of approach. That would be what I would consider a success.

MS. WORTH: Okay. I'm going to ask a question about FTEs under the PBR. In Exhibit B-3, BCUC IR 1.2.0, there was a preamble saying 2017 increases of 67 FTEs, 25 outside base O&M, 2018 increase of 79 FTEs, 58 outside base O&M. So if I look at BCUC IR 1.2.5 and the response, it appears that you were attributing these increases to processing and administrative efforts occasioned by an increase in new services, mainly. If this is a fair interpretation of what your answer is, wouldn't there be economies of scale in processing and administrative functions to be expected, so that staff increases might be moderated? Or are those actually reflected in the increases that you have reported?

MS. ROY: Sorry, could you just summarize that question one more time?

MS. WORTH: Sure. So, as an operation adds service, presumably there would be sort of economies of scale. So what I'm asking is, do those additions of the FTEs that are attributed to the increase in new services reflect those economies? Or are those to be found at a later date, once FEI has actually sort of got those

workers up and running.
MS. ROY: I don't know if John or anybody else here could respond to that. All I know is about the -- you know, we add FTEs to support operations, we have to develop an entire crew, I understand. And that's how it works. I would think any embedded productivities, they would be adopting the same practices that are already established by the existing crews. But I would definitely turn to others to see if there's anything they could add.
MR. HIMMEL: Yes, that's correct. FEI works hard to make sure that we are efficient in all areas of the (inaudible) including in our capital and O&M. So, yes, the efficiencies would be included in the numbers.

Proceeding Time 11:52 a.m. T37

MS. WORTH: Thank you.
On page 11 of the application, there was a passage indicating that, in addition to the formula-related pressures that you discussed regarding the Commission's order, that FEI had continued to experience other capital cost pressures in 2018 due to work that had been reprioritized from previous years, and into 2018 and that they had become urgent and higher priority activities during that period.
So what I'm going to ask is, doesn't the

fact that projects are reprioritized during a PBR, punted to later dates, sometimes known, sometimes unknown, carry with it the risk that this very thing will happen, sort of unforeseen projects or unforeseen timing of projects will occur?

MR. CHERNIKHOWSKY: So it's Paul Chernikhowsky from FortisBC.

I'm not sure that whether you're in PBR or not really has that impact. All we're saying is that in earlier years in an attempt to manage capital pressures, yes, we deferred flexible projects which had no material impact on the system, or for example, were more for business efficiency purposes, and we deferred those to future years. However, at some point that work that is initially considered flexible transitions to become either essential or urgent in nature that you have to complete it. Whether you are in cost of service or PBR, the same effect can happen.

MS. WORTH: So is it fair to say that FEI did not foresee that these particular flexible activities would become urgent and higher priority within the PBR term?

MR. CHERNIKHOWSKY: No, I wouldn't necessarily say that. I'll give an example. So flexible work might be work, for example, at a station where you have work arounds. For example, there might be a safety issues presented but with minor workarounds and crew work procedures, you can still conduct the work safely. Our preference is in the longer term to engineer out those hazards. So that work is initially considered flexible. However, at a certain point, the inherent inefficiencies and risks associated with the work procedures drive it into a more essential type of work.

Another example would be equipment obsolescence, where once a manufacturer has said that they are no longer going to support equipment. Initially you may have spares and so on that you can use to continue operation of the business, but at some point you use those up and then you have to now replace the equipment.

MS. WORTH: Okay, so I'm struggling because my question was whether FEI foresaw that these were actually going to occur within the PBR period. We've had significance variance, particularly in this past year, on the capital expenses, and your answer seems to indicate that FEI actually did foresee that these would come to be urgent or at least a significant portion would become urgent within the PBR.

So I'm just trying to square the circle here in that it seems that FEI wasn't able to actually foresee that the projects that it was putting off were going to become urgent and would require action within the PBR period, and yet you're saying that that's not the case. So I can't -- I think what I was hearing was --

MS. ROY: If I could, maybe it would help just to go back to the discussion we had earlier when I was up talking about the PBR capital formula wasn't set based on a projection of specific projects happening at any time, and in fact it's not a budget in terms of a budget that's approved by the Commission for certain projects. It's just a base that's escalated by a formula. So whether we could have foreseen the specific events happening wouldn't change the amount of the formula that we would have been allowed. That was a decision that came based on, you know, the base and then some certain adjustments to the formula that were decided by the Commission.

So whether or not we could have foreseen it is not really, I don't think, the relevant question. You know, there are a number of things, of course. The further you go into the PBR term there is more things that are going to come up that didn't exist in the base, but whether -- even if we could've foreseen those things under the PBR formula it really wouldn't have changed the formula necessarily.

Proceeding Time 11:57 a.m. T38

Because we didn't take a base and say,

"Here we're trying to adjust it for everything we think it going to happen over the next six years." It was just a number. So that's why it's difficult to answer those questions, but, you know, that's the way we're trying to explain the best we can, you know, what those variances are.

MS. WORTH: And so that's part of the learnings that you're going to take going forward, should you actually apply for another PBR, would be sort of how to actually --

MS. ROY: Yeah. I think specifically the learnings we will take forward are the kinds of things that Paul had talked about. We have -- the biggest problem was with the way the base was set, excluding the VI sustainment capital. Then there's some other things around the in-line inspections and also the growth that's embedded in sustainment, and those are all things we're going to be looking at for sure, trying to fix in the --

MS. WORTH: Thank you. So I wanted to ask a question about planner toolbox. There were a couple of IRs, they were in Exhibit B-3, BCUC IR 1.7.1 and 1.7.2, where there was a discussion of the estimates of annual savings of about $150,000 per year with no reduction in headcount or in revenue requirements since any labour savings would be reassigned to support increased activities and requirements in other areas.

So I'm going to ask -- or actually I'm going to put it to you, there's actually going to be no direct benefit to ratepayers as a result of this initiative, is that a fair characterisation in your view?

MR. HIMMEL: No, that's not correct. There will be a benefit in that there is efficiencies that are gained. It's back to one of the comments that one of the interveners made, it's very difficult to harvest benefits when you have a work force spread over a large geographic territory and you have a growing demand on the workforce from growth and other activities.

So there is a real benefit to ratepayers for it in that we're able to reduce things like overtime and achieve the benefit that way.

MS. WORTH: And will those benefits be tracked for future applications? And for ratepayer information as well as the commission?

MR. HIMMEL: We can. They are very small and really amount to small amounts in our various regional offices. And are both a combination of capital and O&M as planners are engaged in capital activities.

MS. WORTH: I have a question regarding UPCs or use per

customer forecasts. I just wanted to double check whether FEI has used a previously approved methodologies without any variance in estimating the UPC and forecasting demands by rate class?
MR. BAILEY: Yeah, there's no change in previous methods.
MS. WORTH: Okay. Thank you, those are my questions.
THE CHAIRPERSON: Do we have any staff questions? Okay.
MS. LAI: Tanya Lai, BCUC staff.
My first question is with respect to demand forecasts, specifically the mean average percentage error or also knowns as MAPE. In Appendix A-2 of the application FEI discusses its forecast results in terms of the MAPE for residential and commercial UPC and commercial customer additions.
In response to BCUC IR 12.2, in the last paragraph FEI states that its current load forecasting methods result in long-term forecast performance that is significantly better than the industry average. Could FEI please clarify what the industry average is that FEI is measuring against?
MR. BAILEY: David Bailey here. The industry average was established in Appendix A-4, which was the forecasting directive from the I believe 2017 filing. And in that filing we conducted a survey of Canadian and U.S. utilities and combined that with some results from Itron, and from that determined that the average error

for the next forecast is around 4 percent.
MS. ROY: And just to clarify, that's appendix A-4 from the last year's annual review application.

Proceeding Time 12:02 p.m. T39

MS. LAI: And my next series of questions is with respect to FEI's natural gas for transportation program. In Appendix B, page 2 of the application, in Table B-1, with respect to fueling stations, FEI states that they will apply for a CPCN for the construction and operation of fueling stations that do not qualify as a prescribed undertaking under the greenhouse gas reduction regulations.
Could FEI please discuss if there were any fueling stations constructed by FEI during the current PBR period that were not prescribed undertakings under the GGRR?
MS. ROY: I don't believe there are any, but I would just take that subject to check.
MR. GOSSELIN: Yes. Subject to check, I know there was an expansion for waste management which was outside the GGRR. However, subject to check, we'll respond to that.

Information Request

MS. ROY: Your question is whether there was anything that was undertaken under the GGRR, or that did not apply.

MS. LAI: Not a prescribed undertaking.
MR. GOSSELIN: Not under the --
MS. ROY: Oh, okay.
MS. LAI: Under the GGRR.
MS. ROY: I understand.
MS. LAI: So any fueling stations that were not developed for CNG or LNG customer that qualify as an undertaking under the GGRRs.
MS. ROY: Okay, we will do that.
MR. GOSSELIN: Yeah.
MS. LAI: Okay. That's all the questions I have. Thank you.
MS. WALSH: I just have one question and it's actually a clarification question from slide 11 of the presentation. The graph that shows the timing, '17-2018 surplus amortization options. I just wanted to clarify with regard to this graph, for the years 2020 to 2023, what assumptions, if any, did FEI make about amortization of the revenue surplus deferral account?
MR. GOSSELIN: What I did for that slide in the years 2020 through 2023 for amortization was basically plug and play to level out the rate, such that it was as flat as possible. So, there is no -- it's not an amortization rate over three years. It was plugging the numbers to amortize off that deferral account until it hit zero at the end of 2023.

MS. WALSH: Okay. So basically you had amortized out the deferral account to the end of 2023, it's just not like a set amortization.
MR. GOSSELIN: Yes. Correct, yeah.
MS. WALSH: Okay. Thank you.
THE CHAIRPERSON: Okay. I believe we're completed with the questions, then.
So do you have any closing remarks on behalf of Fortis?
MS. ROY: Sure. I'm just going to summarize what I have as undertakings, and if there's anything else that I haven't mentioned, please stand up and let me know.
The first undertaking I had was a breakdown of the training and possibly the other costs that are included in there for the gas workforce management program, and I believe that's BCUC IR 5.3 that was being referred to. Okay?

Proceeding Time 2:44 a.m. T40

I believe we've answer other question which was around the 2017 addition to the surplus deferral and that was -- I said it was $25 million. So I think that has been resolved.
MR. GOSSELIN: Yes, that's correct.
MS. ROY: And just to finally confirm that the vehicle insurance is in the O&M formula. Just to absolutely confirm that one.

Regarding the TIMC deferral account, I have an undertaking to estimate the rate impact by year if we did not include those costs in a deferral account but instead had them in O&M and capital.

For Whistler, a breakdown of the cost by category for the project. So further detail on the estimated costs.

For greenhouse gas emissions, the discussion of the increase in 2017 greenhouse gas emissions as shown in BCSEA 7.1.

Regarding DSM spending we have a discussion of the change in the low income spending from 2018 plan to 2018 projected which is a decrease, but at the same time we're seeing an increase in the savings over that same time period. So to check that, confirm and describe what's going on there. And also to file the 2019 version of the table. That is in the IR that we were referring to there.

And finally, I have to confirm whether or not there were any NGT fueling stations constructed there were not a prescribed undertaking under the greenhouse gas reductions regulations.

Is there anything else that was missed? Okay, great, thank you.

So thank you for our final annual review in our PBR term and I'll be looking forward to discussions with all of the various intervener groups in the upcoming weeks to discuss what we are going to be looking at filing for next time around. And in addition, we do have a benchmarking workshop that you should have all received invitations to, which is scheduled for mid-November.

Thank you.

THE CHAIRPERSON: Great. Thanks everybody for their time. Workshop is adjourned.

(PROCEEDINGS ADJOURNED AT 12:08 P.M.)

I HEREBY CERTIFY THAT THE FORGOING is a true and accurate transcript of the proceedings herein, to the best of my skill and ability.

A.B. Lanigan

A.B. Lanigan, Court Reporter

October 2nd, 2018