BRITISH COLUMBIA UTILITIES COMMISSION

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

And

FortisBC (FBC) Inc
Annual Review 2018 Rates

Vancouver , B.C.
October 24, 2017

WORKSHOP 1:
Annual Review for 2018 Rates

BEFORE:

B. Magnan,	**Panel Chair**
W. Everett,	**Commissioner**
M. Kresivo	**Commissioner**

VOLUME 1

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VANCOUVER, B.C.

October 24, 2017

(PROCEEDINGS RESUMED AT 9:03 A.M.)

THE CHAIRPERSON: Good morning, ladies and gentlemen. My name is Bernie Magnan, and I am chair of the Commission panel on this application. And with me are Commissioners Miriam Kresivo and William Everett.

Also from the Utilities Commission, the staff lead, who is Laurel Ross, and Atalla Buretta, and counsel for the BCUC, Paul Miller.

So, how it's going to work this morning is, after I'm finished this small amount of speaking, we'll go around the room and everyone can introduce themselves. And then we'll ask FortisBC to start their presentation.

If you want to ask questions, I believe as we did last week, you can ask them at the time that the particular subject is being raised. Failing that, there will be a possibility of asking questions at the end of the presentation. We're looking to have a break about mid-morning, depending upon where we're at in the overall presentation, and if there is a free-for-all in asking questions, then perhaps you could direct your questions through the Chair, or look to me to recognize you and pass you on to Fortis. Otherwise

I will let you go straight to whoever is making the presentation.

So, with that said, if I could start on my left for people to introduce themselves, if you would, please. Yes.

MS. LEE: Hi, I'm Cindy A. Lee. I'm with MoveUP.

MS. R. ROY: And Jim Quail. I'm Rachel Roy, also with MoveUP.

MS. WORTH: Leigha Worth, here on behalf of BCOAPO *et al*.

MS. FEENEY: Kate Feeney, also on behalf of BCOAPO *et al.*

MR. ANDREWS: Bill Andrews, I represent the Sierra Club B.C. and B.C. Sustainable Energy Association.

MR. HOBBS: Robert Hobbs, the ICG.

MR. WEAFER: Chris Weafer, representing the Commercial Energy Consumers and the British Columbia Municipal Electric Utilities. And we're also expecting David Craig or Janet Rhodes from the CEC to take this chair.

MR. LOVE: It's Alex Love. I'm with Nelson Hydro, which is part of the BCMEU group.

MR. FILICZ: Sean Filicz, Manager of Electric Utility for the city of Penticton, roughly 36,000 population base and 18,000 customers.

MR. GEISSLER: Dan Geissler with Nelson Hydro. As well, represent about 11,000 meters.

MS. CRAIG: Marg Craig, Nelson Hydro.

MR. REID: David Reid, Manager of operations for city of

Grand Forks, about 2,400 meters.

MR. HARRIS: Ed Harris, city of Penticton.

MS. ROY: Diane Roy, Regulatory Affairs, FortisBC.

MS. MARTIN: Joyce Martin, manager, regulatory affairs, FortisBC.

MR. BYSTROM: Chris Bystrom, counsel for FortisBC.

MR. CHERNIKHOWSKY: Paul Chernikhowsky, director of engineering services for FortisBC.

MR. KLASHINSKY: Curtis Klashinsky, manager of assets and compliance, FortisBC.

MR. MARSHALL: Darrin Marshall, project manager, FortisBC.

MR. KING: Jamie King, power supply operations manager.

MS. PRPIC: Suzana Prpic, director of emergency management and security, FortisBC.

MS. CARMAN: Michelle Carman, manager of customer operations and contact centre, FortisBC.

MR. WONG: James Wong, director of budgeting, FortisBC.

MR. HENDERSON: Brett Henderson, director of finance and accounting, FortisBC.

MR. ANDERSON: Darwin Anderson, manager of IS infrastructure, FortisBC.

MR. WEISBERG: Fred Weisberg, Irrigation Ratepayers' Group.

THE CHAIRPERSON: Ms. Roy, over to you.

MS. ROY: Thank you.

1 MR. HACKNEY: This is Tom Hackney here --
2 THE CHAIRPERSON: Oh, sorry.
3 MR. HACKNEY: -- for BCSEA and Sierra Club of B.C.
4 THE CHAIRPERSON: Okay.
5 MS. ROY: Great. Okay.
6 THE CHAIRPERSON: Hal, is there a way that we could up
7 the volume on the phone? Because we didn't hear the
8 speaker at all.
9 THE HEARING OFFICER: Yes.
10 MS. ROY: Okay. So if you didn't catch that, it was
11 Thomas Hackney from the BCSEA and Sierra Club on the
12 phone.
13 THE CHAIRPERSON: Thank you very much.
14 MS. ROY: Okay, so I'm going to -- good morning, and
15 welcome to everybody. Thank you for coming. I see we
16 have a nice full house here today. I'm going to start
17 by a walk through our agenda.
18 **Proceeding Time 9:06 a.m. T2**
19 First of all, I'll be discussing just
20 running through our approvals sought, and then an
21 overview of the PBR results so far. Next we're going
22 to have Joyce Martin, and Joyce is going to be talking
23 about our revenue requirements and rates including our
24 recent evidentiary update. That will be followed by a
25 section on capital expenditures. On capital
26 expenditures Joyce is going to stay up and talk about

1 the operation of the capital deadband. Paul
2 Chernikhowsky is going to be providing an overview of
3 capital expenditures. Darrin Marshall will be
4 providing a summary of the capital efficiencies that
5 we've been working on so far this PBR plan.
6 Then we'll be moving on to a section on our
7 Z factor which is mandatory reliability standards.
8 Curtis Klashinsky will be talking on that section, and
9 what he'll be speaking to is both Assessment Report
10 No. 8 — and this is the third year that that will have
11 been showing up as a Z factor. We've already had it
12 approved for two years as a Z factor — and also
13 Assessment Report No. 10, which is new this year. And
14 we'll be moving on to our service quality indicators.
15 James Wong will be providing a summary of the
16 performance of our SQIs. Suzana Prpic will be
17 discussing our annual, or sorry, all injury frequency
18 rate, and the reason we're talking about that is
19 because it's two years where we've had performance
20 between the benchmark and the threshold. And then
21 Michelle Carman will be talking about two items.
22 First, the callback feature, and the reason she's
23 discussing that is because we were directed to report
24 on that item by the Commission. And the other one is
25 the average speed of answer, and we had a number of
26 questions so we thought it would be useful to provide

a little bit of discussion on that topic.

So in addition to the presenters that we've got listed here, you can see we have a number of key representatives from FortisBC and they are here to answer your questions. As the Commission Chair indicated, if you have questions on the topics that are being discussed or for the presenters that are up, please ask them at that time. But in addition to that, we will have an open question period at the end of the presentations for anything else.

And that's about it for the agenda.

For approval sought this year, our original application sought a rate increase of .11 percent, and we filed an evidentiary update on October 3rd and the rate increase is now .17 percent, and Joyce will be talking about that after I sit down. We have five deferral account requests this year. The first four you see here are all for regulatory proceedings that are either underway or upcoming, and the last one is for the joint use pole audit which will occur in 2018, and it occurs every five years.

I should also mention that after we filed our evidentiary update, on October 5th the Commission approved a deferral account for the net proceeds of the Castlegar District Office disposition. So when we file our final compliance filing we will be including

that deferral account forecast in our application, but we won't be requesting disposition of that until next year's annual review and that's per the decision in that proceeding.

In addition, in our evidentiary update we're also going to be updating our long-term debt forecast for an actual issue that's going to be happening before we file the compliance filing.

And then the final item -- oh sorry, I missed the joint use pole audit, should have had that up earlier. The final item we have here is the Z factor treatment for the MRS, and Curtis will be speaking more to that one. Yes, Chris.

MR. WEAFER: Chris Weafer, Commercial Energy Consumers and BCMEU. I get confused about the increase and the impact on BC Hydro's increases which come through later in the year. Does the .17 anticipate and include the BC Hydro anticipated rate increase for 2018?

MS. ROY: Yes, I believe BC Hydro's rate increases three percent April 1st, 2018, and so that is included in the .17 percent.

MR. WEAFER: Thank you.

MS. ROY: Yeah. Okay. So we're now setting the rates for the fifth of six years of our PBR term, so we thought it might be a good time to have an overview of

the results so far. What you can see on this slide is the O&M results, and what you're seeing is the O&M adjusted to real 2017 dollars so they're adjusted for inflation. And the red line is the O&M per customer. The blue lines -- and that's in dollars. The blue lines are O&M in dollars, millions. So total O&M dollars.

Proceeding Time: 9:11 a.m. T3

And what you can see from this slide is that O&M is trending favourably, and there has been a fairly marked decline in the O&M per customer, and that is despite the fact that our customer additions have slowed down in recent years.

We have had $4.8 million in savings shared with customers through the earning sharing mechanism. That is primarily due to the O&M savings that we've realized over that timeframe, and that is in addition to the 2.2 million dollars that is imbedded in the productivity improvement factor over that same time frame.

SQIs, in 2014 and 2015, we did have all injury frequency rate was below the threshold, and in 2014, telephone service factor was below the threshold. But we have seen favourable trends since that time, and we have seen improvements over the later years of the PBR term.

So, to summarize in this slide, O&M results have been good, and the SQI results have shown improvement. We have been challenged on the capital front, and we have a discussion later on in our capital section on that part.

So, now moving on to the rates, and this is what our customers see, so of course this matters the most to the customers. Now, those of you who were here last week we showed the same slide for the gas utility, and there you would have seen a very favourable comparison where rate increases were below inflation in every year. You don’t see the same effect here. And there is a number of things that have happened over the time frame and I'll just summarize why we're seeing this kind of a trend in rate increases over the time frame.

So, the rate increases you see here, they don’t really tell the story about what has been going on with our O&M and capital costs under the PBR, and that is really due to two factors. The first is that there have been some large projects and costs that have been absorbed over that time frame. And in addition to that, there has been the existence of a number of deferral accounts, both rate smoothing deferral accounts, and flow-through deferral accounts, and they've influenced the results over the timeframe.

So, it's hard to get a clear picture, really, of what the specific influences were in each year. The items that have had the largest impact on rates over that time, we had a large rate smoothing credit from prior to the PBR term, and that was amortized into rates over the 2015 to 2017 time period. We also had a reduction in return on equity, and there was also a customer benefit from the City of Kelowna acquisition. And all those have had a positive influence on rates, in the sense of lower rates.

But they have been offset by the Waneta Expansion CAPA capacity agreement in 2015 and 2016. That was the time frame over which those costs were phased in. We had the Celgar interim billing adjustment in 2017, and in the 2018 we have the Kootenay Operations Centre coming into ratebase as well.

Overall the past years have shown a slightly decreasing trend in rates. For 2018 what you do is the rate increase is very low, compared to the prior years, and even compared to historical rate increases. And that is because many of the unusual items that occurred earlier in a PBR term, they have been completely phased in now. But we do expect some continuing cost pressures in the future. I don’t think we'll necessarily be seeing rate increases of

close to zero over the next number of years. I think it will be maybe a little closer to inflation, or above inflation. So, any questions? Chris, yes?

MR. WEAFER: Just on that point, and it may be on the record, have you given a rate forecast for future years?

MS. ROY: We have not. We just know that we do have some power purchase type of expenses that are expected to go up, and a number of other items, and we have more capital coming in too as well. So, just based on that, you would expect it would be at least at inflation.

MR. WEAFER: And that's at inflation.

MR. HACKNEY: Tom Hackney here. In regard to the 2015 rate change, the 4.2 number, is that averaged over the year? Or just for some of the increases?

MS. ROY: Yes, we had a rate increase January 1, and then we had a further rate increase I think it was August --July? July of that year. So, that is an average that is taking the July and the January increase, and coming up with an annualized rate for that year. Is that your question, Tom?

MR. HACKNEY: Yes, so not a simple arithmetic addition of the two?

MS. ROY: No, that is correct.

MR. HACKNEY: Okay, thank you.

1 MR. WEAFER: So sorry, Diane, just to finish, because I'd
2 like to get a very clear understanding.
3 MS. ROY: Yeah.
4 MR. WEAFER: So, if the company is looking forward say
5 the next three years, at this point a forecast is rate
6 increase is around inflation?
7 MS. ROY: Do we have a rate increase we can talk to,
8 Joyce?
9 MS. MARTIN: Joyce Martin, FortisBC. No, we actually
10 don't. We have not done the rate increase. We can
11 talk a little bit more about some of the factors that
12 are expected to be influencing it when we talk about
13 the 2018 increase, and we can talk about how those
14 factors might continue into the future, but we haven't
15 at this point specific forecast rates beyond 2018.
16 **Proceeding Time 9:17 a.m. T04**
17 MR. WEAFER: Not even 2019? So, the forecasts of around
18 inflation is just the best guess. The company hasn't
19 done a forecast of rate increases for 2019?
20 MS. MARTIN: That's correct. We have not.
21 MR. WEAFER: Thank you.
22 MS. ROY: Okay. Any other questions before I move on?
23 Okay.
24 And the final slide I'll be talking to,
25 just a summary of -- a review of some of the
26 initiatives that have been undertaken during the PBR

term.

The first one, we've discussed in previous years. So this is the continued sharing of the contact centre staff. And then we have one, two -- we have three other items that we first discussed in this year's annual review, and all of them have or will have O&M savings starting in 2019. The first is the interactive voice response enhancements, about $75,000 of labour savings annually. The SAP integration, that's shared with Fortis Energy Inc., and that will have for FortisBC about $300,000 of energy -- oh, sorry, annual savings.

And the advanced distribution management system, outage management system, where we should be seeing about $200,000 of annual labour savings. Any questions on these specific initiatives?

MR. WEISBERG: Diane --

THE HEARING OFFICER: Could you come to the mike, so people can hear you, please?

THE CHAIRPERSON: Mr. Weisberg, could you just state your name for the records?

MR. WEISBERG: Sure. Fred Weisberg, Irrigation Ratepayers' Group.

On the slide so far, you've provided quite a bit of additional helpful information that's not on the slides. I'm having difficulty recording all of it

in my notes. Is Fortis going to provide notes of what each speaker is presenting?

MS. ROY: Yes, this actually -- this is transcribed, so there will be a transcription that comes out later today, or -- well, in the next few days, anyway. And then all the words we are saying will be recorded.

MR. WEISBERG: I understand the transcripts will be available.

MS. ROY: Yeah.

MR. WEISBERG: There is nothing now, though, that we can have in addition to the slides.

MS. ROY: No, although those numbers I did mention are all included in the IR responses. I'm just summarizing things that are on the record.

MR. WEISBERG: And it's -- the value, for me, is in the summary, so -- but thank you.

MS. ROY: Right. Thank you. Yes, Jim?

MR. QUAIL: Yes, Jim Quail here. I'm just going to raise a point and that's (inaudible) SAP ratio really relating to issues we raised last week at FEI's workshop, that we have questions about whether the basis for allocation of the costs associated with that are appropriate between the two utilities. I think that's really more an issue for the gas utility, because we're saying that they should be paying more. But just wanted to register that point, and it's

1 something we will be addressing in argument, but I
2 don't propose to burden today with repeating the
3 discussion we had last week.
4 MS. ROY: Yes. Thank you, Jim.
5 MR. QUAIL: Okay.
6 MS. ROY: Okay, if no further questions, I will pass it
7 over to Joyce, to talk about our evidentiary update
8 and our revenue deficiency.
9 MS. MARTIN: Thanks, Diane. Good morning. My name is
10 Joyce Martin and I'm manager of regulatory affairs for
11 FortisBC. This morning I am first going to summarize
12 the evidentiary update that we filed on October 3rd,
13 and then I'm going to review the factors that are
14 driving the revised rate increase of 0.17 percent for
15 2018.
16 Before I go on to those topics, though, we
17 do have an erratum to the application, which is being
18 circulated now. And as I understand, that will be
19 Exhibit B-12.
20 This is a correction to Table 10-2 which is
21 the 2017 earnings share and calculation. There isn't
22 any change to the final earnings sharing value or to
23 either the O&M or capital sharing amounts but forecast
24 gross O&M and the adjustments were stated incorrectly
25 in the application. So on this table, lines 3 through
26 10 have been corrected and again the amount of the O&M

1 sharing, that is subject to sharing, which is $1.2
2 million at line 15, remains the same.
3 (ERRATUM SHEET MARKED EXHIBIT B-12)
4 **Proceeding Time 9:22 a.m. T05**
5 MS. MARTIN: So moving on to the evidentiary update, this
6 table is taken from the cover letter. I'm sorry?
7 MR. WEAFER: We just got these. Do you mind if we just
8 see this first?
9 MS. MARTIN: Yes.
10 MR. WEAFER: Thanks.
11 Would you mind going through that again,
12 what the erratum is
13 MS. MARTIN: Sure. Yeah. The lines that have changed in
14 that are lines 3 through 10, beginning with the gross
15 O&M expense and deducting the line items that are
16 accounted for outside of the O&M formula expenditures.
17 So when you reach line 15, which is the O&M that is
18 subject to sharing, of $1.2 million, that is the same
19 value that was filed in the application.
20 And so there is no change to the amount of
21 earnings sharing for 2017, but there was an error
22 working back from the $1.2 million to be shared,
23 working back up to the gross O&M expense.
24 MR. WEAFER: Can you point out what the error was? The
25 net numbers -- the result doesn't change.
26 MS. MARTIN: That's right.

1 MR. WEAFER: But there were offsetting adjustments?
2 MS. MARTIN: That's right. What we did was to identify
3 the $1.2 million that we expect to be sharing, and
4 then in the application -- and then we added back --
5 so instead of subtracting down from the gross O&M, we
6 had added back from the $1.2 million sharing, if you
7 can get that concept. And unfortunately the values
8 that we included as being outside of the O&M formula
9 were wrong.
10 That's not working for you, Chris?
11 MR. WEAFER: I'm going to have to take it away.
12 MS. MARTIN: Okay.
13 MR. WEAFER: Because the cynic in me says you've got the
14 result, so then you put the numbers in to get to the
15 result.
16 MS. MARTIN: Yes. Yes, that's right.
17 MR. WEAFER: Okay.
18 MS. MARTIN: So what we did was to go to each department
19 and identify how much earning -- how much O&M we
20 expected to have available for sharing with customers.
21 That's the $1.2 million.
22 MR. WEAFER: But the inputs changed.
23 MS. MARTIN: Well, we just -- it was just an arithmetic
24 exercise to back up from the sharing to add in the
25 expenditures that are outside of the O&M formula, and
26 then to arrive at the expected O&M.

1 THE CHAIRPERSON: If I may, at line 13, you have the
2 actual projected base O&M of $52,872. What was that
3 number in the original?
4 MS. MARTIN: I don't actually --
5 MR. QUAIL: We have it here.
6 MS. MARTIN: -- have the original in front of me. May I?
7 MR. QUAIL: $52,872. $52.872. It's the same number.
8 THE CHAIRPERSON: So it's the total at line 11 that has
9 changed. And it's now $3,418, and it was $3,816.
10 MS. MARTIN: Yes, line 11 and line 3 are changed.
11 THE CHAIRPERSON: Okay.
12 MR. QUAIL: Yeah.
13 THE CHAIRPERSON: But you still arrive at the -- line 13
14 is still the same as it was.
15 MS. MARTIN: Line 15 is the same.
16 THE CHAIRPERSON: 15, yes.
17 MS. MARTIN: The sharing amount is the same.
18 THE CHAIRPERSON: And 13 is. Okay, thank you.
19 MR. QUAIL: Mr. Weafer is cynical enough to articulate
20 that. I'm just cynical enough to assume it.
21 MS. MARTIN: Yeah, it was just a matter of how we came
22 about with the $1.2. You could either go and say,
23 what is your expenditure going to be for the year, and
24 add those up, and rather we went and said, "What do
25 you think your savings are going to be?" And added
26 those up, and worked backwards.

THE CHAIRPERSON: Thank you.

MS. MARTIN: This table is taken from the cover letter that we filed with the evidentiary update, and it identifies the items that were revised, along with the revenue deficiency and the rate impact for each of the items. And as you know, the revenue deficiency that we filed in the original August 10th application was $400,000 and at that time we were requesting a general rate increase of 0.11 percent.

The first item that was updated was the average weekly earnings, or AWE, which is one of the two cost drivers for formulaic capital and O&M expense during the PBR term.

Proceeding Time: 9:26 a.m. T6

The escalators are used for the period of July through June, but at the time of the August filing StatsCanada had not yet released the June average weekly earnings index. And so an update was required. In fact, StatsCanada revised the May index value at the same time, and so that value is also reflected in the evidentiary update as well. And as you can see in the table, the increase in the revenue deficiency that is associated with the changing average weekly earnings is very small, it is only about $9,000 and it doesn't have any measurable impact on 2018 rates.

The second set of updates relates to various deferred charge accounts both in 2017 and 2018, and those included a couple of corrections, in addition to revising the forecast for certain deferral accounts in order to reflect the status of various regulatory proceedings. And I won't identify them individually since they are described in the responses to these two information requests, BCUC IR 1.23.1, and CEC IR 1.36.1. As you see, the increase to the revenue deficiency that is associated with the deferred charge accounts, is 210,000. And finally on the bottom line of the table, the revised revenue deficiency is now 619,000, which is an increase of 219,000 from the original filing, and the revised rate increase is now .17 percent.

This graph shows the components that make up that revenue deficiency for 2018, and it does this by identifying changes in the various cost accounts from the values that are imbedded in 2017 rates. By doing that we can identify which components are causing rate pressures, and which ones are reducing rates.

To start with the baseline which is zero on the vertical axis is the 2017 revenue requirement. And in order to read this graph, as you start on the left and follow each one of the columns across, the

1 components that are shown in yellow are the ones that
2 contribute to the revenue deficiency. That is, they
3 increase revenue requirements and increase rates. And
4 conversely, the green-coloured components act to
5 reduce revenue requirements until we get to the final
6 revenue deficiency of 619,000 shown in blue on the
7 right, and that is the same revenue deficiency that we
8 saw in the last slide, and it is equal to the rate
9 increase of .17 percent.
10 The first column in the graph is
11 contribution of changes in load. And it is the
12 largest contributor to the revenue deficiency this
13 year. The reason for that is that we are forecasting
14 a load decrease compared to the 2017 approved load.
15 There are two customer classes that are primarily
16 responsible for the load decrease. The first one is
17 the industrial class. And our forecast is based on
18 input from the industrial customers themselves. And
19 this year we have forecast accounting for
20 approximately 90 percent of the industrial load.
21 There were several customers who forecast load
22 decreases for 2018.
23 The second customer class that is
24 decreasing is the residential class, which is
25 experiencing declining energy use on a per-customer
26 basis. This is the first year in which we've

identified a declining use per customer. And although residential customer counts are increasing, that is not enough to offset the declining use rates.

Overall, that lower sales load means that if there were no other cost changes, rates would have to rise in order to cover the existing costs, and that would be a revenue deficiency of about $5.8 million.

The second column is the cost of power supply which is $3 million lower than in 2017 and that is due largely to the reduced load that we just talked about, as well as to lower power purchase from BC Hydro and to increased savings from market purchase arrangements that we have already entered into for 2018.

Next over we gain a small benefit from earnings on work that has been performed for a third party, as well as a higher revenue from joint use contracts and from new customer connections.

The fourth column is O&M expense, and it increases by just under $900,000. Inflation and customer growth caused an increase in the formula O&M by about 1.3 percent. That accounts for about $549,000 and there is also an increase in expenses outside of the O&M formula, primarily related to the mandatory reliability standards. There are two Z-factor events as well as the 2018 compliance audit,

and Curtis will be speaking about those items later this morning.

Proceeding Time: 9:31 a.m. T7

The next column is depreciation and amortization expense, and it is also a factor in mitigating rates this year. This cost category includes the higher depreciation on assets that are being added to rate base. That higher depreciation is about $2.4 million, but as you can see, it's more than offset by lower amortization of deferred charges — some of which Diane talked about — so that overall we do have a reduction in the revenue deficiency of about almost $3 million.

And just to reiterate a bit, that change in amortization expense for the deferred charges is accounted for mainly by three items. And those are the difference in the flow-through account between the two years, in addition to two large and non-recurring accounts. Those are the Celgar interim billing period adjustment account and the balance of the 2014 interim rate variance account. Both of those accounts were extinguished in 2017. They do have a significant impact on 2018 rates, but as Diane said, we don't foresee any future deferral accounts that are going to be influencing rates to that same degree.

The last two columns, which are the

1 financing and return on equity and taxes are largely
2 driven by the items in that depreciation and
3 amortization categories, that is either by increases
4 to the rate base or tax timing differences that are
5 related to the deferred charges.
6 And I also want to mention that we haven't
7 included in the evidentiary update the corporate tax
8 increase that was proposed in the September 11th B.C.
9 budget update. It's our practice to only include the
10 impact of tax changes once they've been enacted by
11 legislation, so if and when that occurs the income tax
12 difference would be treated as a flow-through item on
13 the tax line and recovered in 2019 rates. And just
14 for order of magnitude, if it's enacted -- if it were
15 to be enacted before 2018, it would increase the
16 combined tax rate by 1 percent, that's about $350,000
17 or a 0.1 percent increase relative to 2018 rates.
18 And finally, again in the last column we
19 see that overall revenue deficiency of $619,000 and
20 the rate increase of 0.17 percent.
21 MR. WEAFER: Joyce.
22 MS. MARTIN: Yes?
23 MR. WEAFER: Sorry, I don't know if this is the point is
24 time. Diane had mentioned -- and I'm going to go back
25 to what 2019 looks like and go forward.
26 MS. MARTIN: Sure, sure.

1 MR. WEAFER: And just to give some context, I know we're
2 coming to the end of the PBR term.
3 MS. MARTIN: Yeah.
4 MR. WEAFER: We've had fairly smooth rates through the
5 term and one of the issues we'll be dealing with going
6 forward is do we let the PBR go forward? So I'm not
7 trying to go out of scope here, but --
8 MS. MARTIN: No, no. I think this is a good time,
9 because we can kind of walk through what we can
10 perhaps see for each of these cost accounts going
11 forward.
12 MR. WEAFER: Right.
13 MS. MARTIN: Yeah.
14 MR. WEAFER: And the others I just raise them for the
15 BCMU members who are trying to anticipate rates, tell
16 their councils, "Go forward."
17 MS. MARTIN: Right.
18 MR. WEAFER: So I'm not trying to pin you down to a
19 number but as best --
20 MS. MARTIN: Yeah, fair enough, Chris. Sure.
21 MR. WEAFER: -- as best we can get to, what do you see in
22 2019/2020 following this PBR term of four years?
23 MS. MARTIN: Yeah. So the first thing that we see that's
24 different here, if you look at the volume related
25 column, which is the first one, what we've been seeing
26 up to this point in time is a year over year increase

in sales load, which is generally a mitigating factor when it comes to rates.

As I said, 2018 is the first time that we are anticipating or that we've seen significant decrease in residential use per customer which is, you know, a large component of the rates. And so to the extent that we expect that to continue into the further, that would continue to put upward pressure on rates. And there are a couple of places in the IR responses where we identified that we think that declining use per customer is influenced largely by or partly by demand-side management and some of those other savings that are shown in the load forecast segment.

We don’t have a future forecast of that industrial decrease, so whether that's going to carry forward into the further, we don’t know. But certainly the decreasing load, if it continues, will put upward pressure on rates.

Proceeding Time 9:36 a.m. T08

Then when you look at power supply, if you have lower load, you would have lower power purchase volumes. However, we do still have rate pressures as a result of contracted escalations in our long-term contracts, the BC Hydro contracts, the Waneta expansion, the Brilliant expansion. So there is --

even though load is decreasing, we still have some of those upward pressures.

The other major item is that deferred charge issue that we talked about. We had over $5 million of rate mitigation this year because of the way deferred charge amortization changes from one year to the next, and we don't, at this point, see any of those large kind of one-off.

So those are the rate pressures that we see going into the future and, as I said, we haven't quantified them at this point, but it's very unlikely that we'll be seeing a rate increase in the neighbourhood of the 2018.

MR. WEAFER: Sorry, can you -- I didn't --

MS. MARTIN: It's unlikely that we're going to be seeing future rate increases that are as low as the forecast 2018 one.

MR. WEAFER: And your comment earlier was around inflation, is the best estimate for 2019 at this point?

MS. MARTIN: I can't say that I've got any analysis behind that because we just haven't done that exercise yet.

MR. WEAFER: Okay. Thanks very much.

MR. QUAIL: I have three issues. Two of them are O&M-related, and I assume they belong here. The third,

wherever you want to deal with it.

Two of them deal with actually an enquiry I sent to Diane, who advised that she was pleased to comply. And one was for some workforce data similar in its general character to the kind of stuff that the gas utility has filed. And I don't know if that's available. And if that could just be put on the record, I won't have anything further on that today.

The second issue that I had raised with Diane is, I'd appreciate some commentary on the impact of B.C.'s electrification policy, prescribed undertakings under the *Clean Energy Act* and other developments, and how you see them on the horizon.

The third issue I might as well flag now is, interested in information about the services being contracted for with a company called Clevest, C-L-E-V-E-S-T, for the record. Some description of what services are being contracted, what their operational impacts are, service impacts, and revenue requirements impacts of those contracted services, please.

MS. ROY: Okay, I'll start with that, then, Jim.

MR. QUAIL: Okay.

MS. ROY: So the first question you had was regarding the head count and FTEs, by affiliation, for the years 2013 to 2017. And we do have that prepared so that

1 will be handed out, and I guess that will be Exhibit
2 B-13.
3 MR. QUAIL: Thank you.
4 (HEADCOUNT AND FTES BY AFFILIATION FOR THE YEARS 2013
5 TO 2017 MARKED EXHIBIT B-13)
6 MS. ROY: And your second question was regarding
7 electrification. So I'll start on that, and if
8 anybody else has more to add, they can do that.
9 So the OIC 101, 2017, the province passed
10 amendments to the *Greenhouse Gas Reduction Regulation*,
11 or the GGRR, as we call it. And it established a
12 number of prescribed undertakings pertaining to
13 electrification in the province. And in that OIC,
14 there are a few references to the Authority, which
15 means BC Hydro, but otherwise those prescribed
16 undertakings, as we understand them, are open to other
17 public utilities including FortisBC.
18 So we are currently assessing the prospects
19 for electrification in our service territory. There
20 are a few things that are underway; for example, we
21 are participating in the Accelerate Kootenays project,
22 which is where we're installing DC charging stations
23 in our service territory. As you know, we have our
24 Community Solar project before the Commission as well.
25 But other than that, there is a province-
26 wide assessment of electrification opportunities being

1 undertaken with BC Hydro as part of the conservation
2 potential review, and that assessment is not yet
3 complete. And because it's not complete, we can't
4 really comment yet on any further initiatives that we
5 might be undertaking.
6 **Proceeding Time 9:40 a.m. T09**
7 And we do need to consider, of course, the
8 economics and rate impacts of any initiatives that we
9 do undertake. So that's at the highest level. Did
10 you have a specific question?
11 MR. QUAIL: Well, just survey -- lay of the land, to what
12 extent you see it as affecting the trajectory over the
13 next period.
14 MS. ROY: Okay. Yeah. You know, I don't think these are
15 -- they are definitely things we'll be pursuing. I
16 can't really quantify how big they'll be at this
17 point.
18 MR. QUAIL: Of course, in the context of FortisBC, to
19 some extent that represents a shift, to some extent,
20 away from natural gas to use of electricity, although
21 there is other fuels as well that are displaced, for
22 example, in transportation.
23 MS. ROY: That is a potential outcome, yes. Yeah.
24 And then your third question was regarding
25 Clevest. And I think I'll turn that to -- who is
26 going to answer that one?

1 Clevest is -- I'm just trying to recall
2 which software that is. That's for the workforce
3 management? Okay. Dale Ernst is here, and I think he
4 can provide some information on that.
5 MR. ERNST: Dale Ernst, FortisBC, manager of system
6 operations. Clevest is a mobile workforce management
7 tool. So, it's part of our advanced distribution
8 management system project. Phase 2 of that project
9 was to replace our current tool, which is used to
10 dispatch work to our field workers, which is currently
11 our dispatch tool. So Clevest is essentially a
12 replacement for that. There's a number of drivers
13 behind that, but Clevest is a replacement for
14 workforce management for our field workers.
15 MR. QUAIL: And wanted to know what kind of service
16 impacts you see this having over the coming period.
17 MR. ERNST: I'm not sure I understand the question.
18 MR. QUAIL: What impact does it have on the services you
19 provide your customers?
20 MR. ERNST: One of the main benefits to customers is
21 improved visibility of our work that we're providing
22 in the field. So, once the advanced distribution
23 management project is complete -- Phase 2 actually
24 just went live a couple of weeks ago. So, improved
25 visibility for customers, like real-time information
26 transfer as far as outages, planned outages and

unplanned outages on the system are available through our customer outage portal. So one of the main drivers behind replacing our dispatch was improved flow of information, both internally within FortisBC and to our customers.

MR. QUAIL: So it sounds like it's essentially an improved platform for providing similar kinds of services, but with, I'll say, better visibility and improved interface with customers. Are there other operational impacts you see?

MR. ERNST: Other operational impacts would be, I would say, the main benefits would be improved flow of information and visibility of the information. So we had a number of systems that didn't share information easily, I would say. Now we have a tool that can share information between departments and give real-time visibility to the status of the work as it's happening.

MR. QUAIL: Okay, thank you very much.

MR. BYSTROM: Chris Bystrom, for FortisBC. That handout that just went around, I think we should mark that as Exhibit B-13.

COMMISSIONER EVERETT: Bill Everett, Commissioner. This may be a naïve question, but you say your demand load went down, but you also said that your customer base went up.

1 MS. MARTIN: That's right.
2 COMMISSIONER EVERETT: Is that because the increased
3 customer base had no effect on the total demand
4 because of demand-side management? Is that the
5 reason?
6 MS. MARTIN: Well, we are experiencing customer growth,
7 modest customer growth. I think it's barely around 1
8 percent.
9 COMMISSIONER EVERETT: Mm-hmm.
10 MS. MARTIN: But what we're also experiencing is that the
11 existing customer base is using less energy
12 individually and so use on a per-customer basis is
13 decreasing. But the additional load from the new
14 customers is not enough to overcome that.
15 COMMISSIONER EVERETT: Okay.
16 MR. QUAIL: I would assume that's because new (inaudible)
17 are more energy-efficient than older ones, so new
18 customers that are represented by new construction are
19 using less energy and also appliances and everything
20 else are becoming more energy efficient.
21 MS. MARTIN: That's certainly a factor, yes.
22 MR. QUAIL: Are there other factors you think --
23 MS. MARTIN: There may be other factors that we don't
24 necessarily register. It would depend on dwelling
25 size maybe changing, the type of appliances that
26 people are choosing to install, general energy

1 awareness. But the fact that new customer growth is -
2 - we are experiencing some new customer growth, but
3 that is not really what is driving the declining use
4 per customer.
5 **Proceeding Time: 9:45 a.m. T10**
6 MR. QUAIL: Thank you.
7 MS. MARTIN: The next topic is the company's capital
8 expenditures in 2017. Paul and Darrin are going to
9 discuss both the level of capital expenditures, and
10 our efficiencies within the capital expenditure plan.
11 To begin with, I'm going to review the treatment of
12 the expenditures that are above the dead band.
13 The treatment in the application is the
14 same treatment that was approved for FEI in its 2017
15 rates proceeding. In that decision, the commission
16 confirmed that the capital expenditures that are above
17 the dead band get removed from the earning sharing
18 calculation and that they are added to rate base in
19 the beginning of the next year. In this case, that is
20 January 1st, 2018.
21 In 2017, we expect to exceed the formula
22 capital envelope by about 15.3 million dollars which
23 exceeds the dead band, both in terms of the one-year
24 10 percent, and the cumulative two-year 15 percent
25 thresholds.
26 So, again, the treatment of the capital

that is in excess of the formula, is that only the spending that is within the dead band is subject to the earnings sharing.

In 2017, the ESM calculation in table 10-2 that we circulated this morning shows on line 27 that $11.268 million is the amount of the adjustment that is supplied to stay within the dead band. In this case, again, that is the two year variance of 15 percent. So, that is the amount that is excluded from the earnings sharing and which is going into rate base on January 1st, 2018. And the remainder of the 2017 expenditure above the formula is 4.038 million which is shown on line 30 and that is the amount that is subject to earnings sharing during the PBR term.

We did have some questions in this proceeding about whether it would be appropriate to rebase the formula, and consistent with the decision in FEI's 2017 rates proceeding, we are not proposing to change the formula at this time. And we set out our reasoning for that in the response to BCUC IR 1.12.9.

The first reason is that with only two years left in the PBR term, 2018 and 2019, it is not very practical to rebase at this point. The capital plan for 2018 has already been set, and it would be extremely difficult to respond to a change in the

1 formula amount at this late point in time. We did
2 answer a number of IRs that explained how the company
3 has carefully considered the capital work that remains
4 to be done over the rest of the PBR term, and how
5 we've set our capital needs going forward.
6 Second, the components of the PBR plan are
7 all interdependent, and we believe that it is much
8 more appropriate to look at the capital formula, and
9 at the level of rebasing as part of a total PBR
10 package the next time there is a PBR plan up for
11 review.
12 Third, rebasing wouldn’t result in a better
13 outcome, we believe, and that has been discussed in
14 the FEI workshops, both last year and for those of you
15 who were at the workshop last week again this year,
16 and the reasons are these:
17 One, is the design of the PBR plan itself.
18 The plan was designed in a way that recognized the
19 possibility that capital expenditures would exceed not
20 only the formula amount, but also the dead band. So,
21 we believe that it's not necessary to change the
22 design of the plan when those over-expenditures occur.
23 Two, there is very little difference to
24 customers, or to FBC between a rebasing scenario, and
25 retaining the existing base amount. We explained that
26 in the response to BCUC IR 1.12.10, where we said that

the only differences would be that difference between the company's equity earnings and the earnings sharing amount, and the reason for that is the flow through treatment of the depreciation interest expense and income taxes.

Proceeding Time 9:50 a.m. T11

The third reason is that we are achieving capital efficiencies. And again, that's a topic that Paul and Darrin are going to address shortly.

And fourth, it's not clear what would be the proper amount by which we ought to rebase if we were to decide to do that. One approach obviously would be to add to base capital the amount that's outside of the dead band in 2017. However, we have said that we expect the 2017 variance to be the highest variance during the PBR term, and so to add that 2017 value may not be appropriate.

And then again, given the short amount of time left in the PBR plan, it's not likely to be worthwhile to undertake another process that would help us decide on the amount that should be added to the base.

And again, that's because the impact on rates in the remaining period of the PBR term would be very small.

Nevertheless, by way of illustration, this

1 slide shows the impact of rebasing the 2018 formula
2 capital if we were to use that $11.3 million from
3 2017. The first column shows the amounts within the
4 formula, $43.3 million; the dead band of $4 million;
5 and the $11.3 million that is over the dead band,
6 which is added to the rate base at the beginning of
7 2018.
8 And the second column shows the outcome in
9 2018 of increasing the formula amount. The rebased
10 amount is the 2018 formula value that's already been
11 calculated of $43.8 million, plus the rebased amount
12 of $11.3 million. And that would give us a new
13 formula capital amount of $55.1 million, all of which
14 would go into rate base at mid-year. It would also
15 give us a new higher dead band amount and, of course,
16 the higher formula and amount for 2019 as well.
17 MS. ROSS: Would now be (inaudible)?
18 MS. MARTIN: Yes.
19 MS. ROSS: Okay. So under these two scenarios here, so
20 the first graph you have, the $11.3 million is added
21 to opening rate base in 2018.
22 MS. MARTIN: That's correct, yes.
23 MS. ROSS: And then under the second graph, the $11.3 is
24 essentially added to the formula capital amount. It's
25 under a rebasing scenario.
26 MS. MARTIN: That's right.

MS. ROSS: So I'm wondering, and this might be an undertaking, but I'm wondering if you could provide the 2018 and 2019 rate impact under each of those scenarios, for the $11.3 million?

MS. MARTIN: Yes, we can.

INFORMATION REQUEST

MS. ROSS: Thank you.

MS. MARTIN: Jim?

MR. QUAIL: So, some general comments. A lot of the commentary in the electric utility materials this time around about the capital formula and how it's working are very similar, I think a lot of is verbatim to the commentary for the gas utility.

MS. MARTIN: Yes.

MR. QUAIL: And again, we had a considerable amount of discussion last week that probably isn't profitable to repeat here.

But just -- would you agree that -- does the company agree that the general characterizations about whether and to what extent the PBR capital formula is working in this cycle apply similarly to the electric utility. If not, we can probe into it further. Do you have any comments about that? Or maybe you want to comment later, but I'd be interested in knowing -- do we retrace all the same steps this week, or is there an understanding of the general

1 characterizations about problems that are perceived
2 with the capital formula apply similarly to the
3 electric utility?
4 MS. ROY: So, it's Diane Roy speaking. I think that's
5 generally the case. The one difference on the gas
6 side is we are experiencing significant customer
7 growth, and that has had a real impact on the growth
8 capital. And that growth capital has really been the
9 major issue in the gas side, and the sustainment
10 capital has been less of an issue there. I think what
11 we're seeing on the electric side, it's more of a
12 mixed bag, but I guess you would characterize it as
13 more the sustainment and other capital is causing most
14 of the challenge there. And there's some more unique
15 things happening on the electric side as well.
16 But in both cases, we are seeing some
17 challenges with -- we are obviously seeing challenges
18 with containing our capital spending, even within the
19 dead band, let alone within the formula, and those are
20 things we would look at in any future PBR or any other
21 type of application we'd be bringing forward.
22 MR. QUAIL: Thank you.
23 MS. MARTIN: Thanks. And so just as a summary, as Diane
24 just said, we do recommend retaining the capital
25 formula at the existing level, and we expect that we
26 would revisit the base and the formula itself, and

generally the treatment of capital expenditures when we next consider a new PBR plan.

Proceeding Time: 9:55 a.m. T12

MR. WEAFER: Chris Weafer. Sort of a comment and a question and, as we look forward to a new capital formula or not to go forward. I'm not trying to get detail on that now, but as Jim points out, we heard the same, similar criticism by the company of how the capital formula worked for gas as it does for electric. And so what I take away as a layperson on that is it's difficult to forecast your capital. There's nothing that's occurred on the electric side or the gas side that you wouldn't have the same variables in a new PBR term.

Is that fair to say? Like, what you're seeing is your anomalies will also occur in a subsequent term, you can't predict it as well as you seem to be able to predict your O&M under formula.

MS. ROY: Okay. I think one -- Diane Roy speaking -- one unique item is the impact of adding customers, which is difficult to predict on capital. I think Paul may have more to add, but I think that generally speaking, you know, we -- from what I understand, all utilities that have PBR plans have challenges with capital. And it's often around how do you build a PBR plan that can allow for, you know, unusual, lumpy, unforeseen

capital that comes along. Not that we can't do a good job of coming up with a five-year capital plan, which we can, but that there's always going to be factors that come up during a longer time frame that are difficult to control.

So it's really about how could you -- if you were going to have a formula or a PBR plan, how could you design something that would allow for those things to happen without making the PBR plan basically unworkable. And, you know, we have had -- we did have the capital deadband in this plan, which has allowed us to kind of carry on with the plan. But I still don’t -- I think everybody would agree it's probably not the most ideal way to handle it, and we'll be looking at other ways to look at that.

Paul, do you have anything else you'd wanted to say? or do you think that's -- okay, yeah, Paul's going to talk more when he's up in -- up as well.

MR. WEAFER: Thank you. That's fine, thanks.

MS. ROY: Okay.

MS. MARTIN: If no further questions on the deadband treatment, then Paul will discuss the capital plan itself.

MR. CHERNIKHOWSKY: So good morning. My name is Paul Chernikhowsky. Again, I'm the director of Engineering

Services at FortisBC. Relevant to our discussion today, some of the business functions in my area include the system planning and asset management groups, in other words, our capital and maintenance planning, our engineering design group, and our mandatory reliability compliance functions.

I'd like to briefly walk you through a discussion of our sustainment capital expenditures for 2017. And first, I do want to note two differences from the PBR formula as it applies to FBC. And I'm doing this because there were a number of Commission IRs that made reference to FEI responses in the FEI Annual Review from last year.

So first, unlike FEI, which has a formula for growth capital and sustainment capital, FBC only has a single capital formula. And so we have a single capital envelope which we balance growth and sustainment expenditures within. Second, unlike FEI, FBC records work driven and funded by third parties as gross PBR expenditures and not net of any contributions in aid of construction.

So as early as 2014 we began to identify pressure staying within the PBR capital formula. We already hadn't identified portfolio of sustainment capital work to execute on, and that was first identified back in 2011 and it was articulated in the

1 2012 long-term capital plan. And at the same time, of
2 course, we do have an obligation to serve new
3 customers that apply under our Rate Schedule 74 as new
4 extensions. So, under PBR as I mentioned, we have the
5 obligation to balance those expenditures between
6 growth and sustainment.
7 **Proceeding Time: 10:00 a.m. T13**
8 So, we reviewed our sustainment portfolio
9 to see if there were any opportunities to reprioritize
10 work. And that included potentially execution of work
11 in future years. In BCUC IR 1.10.1, we talked about
12 some of the factors that have been impacting our
13 capital expenditures over the PBR term. Some of them
14 are more quantifiable than others.
15 First is the formula impacts. There were
16 adjustments to the factors that were used to determine
17 the allowance for customer additions. In some years,
18 for example, 2015 we also saw customer growth in
19 excess of what we had forecast. We also had a number
20 of unanticipated 3rd party driven projects.
21 We have had improved levels of scope
22 definition, that have refined our cost estimates for
23 work that is being done in current years compared to
24 what was estimated quite a while ago.
25 And then last is external factors such as
26 currency exchange rate for equipment and services that

we purchased from the US, and that is both direct and indirect because of course some materials are services that you purchase in Canada of course have raw materials that are coming from the US.

So, ultimately, while we may have been able to --

MS. BURETTA: (inaudible) In response to the IR you also mentioned miscellaneous factors. What would that entail?

MR. CHERNIKHOWSKY: Sorry, I missed the first part of the question?

MS. BURETTA: In response to that IR 10.1, you also list miscellaneous factors.

MR. CHERNIKHOWSKY: Miscellaneous factors is basically referring to any other scope changes that would have occurred, better information. It's covering off the other general areas I'd say that would improve our cost estimates.

MS. BURETTA: Okay, thanks.

MS. WORTH: Leigha Worth here, for BCOAPO. I have a quick question. You mentioned the sort of foreign suppliers. When you're actually -- when FBC looks at that, in the assessment of price, is there any allowance for exchange risks? Sort of differences, fluctuations in the currency exchange? And if so, how is that done?

1 MR. CHERNIKHOWSKY: Are you talking about hedging? Is
2 that what you are referring to? Or simply optimizing
3 purchases that are subject to exchange rate
4 variability?
5 MS. WORTH: When you're looking at -- when you're
6 projecting the cost of a project, and there is going
7 to be a purchase from a foreign supplier, in that
8 projection, do you include some sort of allowance to
9 offset any potential negative effects of currency
10 fluctuations, and if so, how is that actually
11 calculated?
12 MR. CHERNIKHOWSKY: Okay. No. So when the PBR plan was
13 first developed back in 2014. Again, it was based on
14 a long-term capital plan that was identified in
15 previous years, and future cost forecasts for projects
16 would have used current day exchange rate assumptions.
17 Because of course speculating beyond that obviously is
18 just that speculation. Currency exchange rates could
19 go up or down, and so we just use a constant number.
20 There is, in the PBR formula, some inherent capture of
21 that through the inflation factor, but in our case we
22 were finding that that inflation factor didn’t fully
23 represent or reflect the currency exchange rate
24 variability that we were seeing.
25 MS. WORTH: Okay, and is the impact of that lack of
26 reflectivity positive or negative? You said it didn’t

fully capture that or reflect it. Is the impact on your projections that you are under-projecting or over-projecting the price?

MR. CHERNIKHOWSKY: In this case, fundamentally we were under-projecting. When the estimates were done, prior to the PBR term, effectively they were using the near parity exchange rate. And in recent years of course, we've seen exchange rates more in the range of 1.3, 1.35.

MS. ROY: So, Diane Roy speaking, just to give you a bit of a reference too, in our response to BCOAPO IR 3.4, that is where we set out the assumptions that we had made, the imbedded kind of exchange rate at the beginning of the PBR plan, and we compared it to the actual realized exchange rates that have occurred over that time frame. So, you can see there what the difference was, and basically, you know, it shows there that the exchange rate at the time of setting it was close to one, and now it is more like .76 for 2018, so that is a fairly significant exchange rate change over that time period.

MS. WORTH: Thank you.

MR. CHERNIKHOWSKY: Okay, any other questions before I continue?

So, ultimately what it comes down to is while we may have been able to absorb some or a few of

these factors, when they're all combined, it was simply unsustainable to stay within the allowed formula by simply reprioritizing capital work into future years. And that has occurred in spite of our efforts to find capital efficiencies under PBR, and Darrin is going to talk about that shortly.

Proceeding Time 10:06 a.m. T14

MR. CHERNIKHOWSKY: So, really the question becomes why now? Why 2017? As Joyce alluded to, it does represent a catch-up year, we do expect this to be the highest level of capital expenditures and ultimately it's because there was an increasing backlog of capital work which would have presented safety or reliability impacts if it wasn't addressed in a timely manner.

And additionally, if that queue of work kept growing, it would tax our ability to execute on it effectively in future years. And so it's for that reason that we're seeing projected expenditures higher than formula, and higher than the dead band in 2017.

But ultimately, to summarize, we are executing on work that we said that we would execute on during the PBR term, and that is to ensure the safety and reliability of the system.

MS. WORTH: A quick question here. Leigha Worth again for BCOAPO. There was roughly a $4.2 million in

1 spending on Ruckles and UBO No. 4 that was actually
2 advanced from 2018 to 2017. And that accounted for
3 the increase in 2017 capital spending overall.
4 Now, that was actually sort of put ahead.
5 Was that for a safety reason? Was the advancement
6 necessary?
7 MR. CHERNIKHOWSKY: I think Mr. Marshall can answer that
8 one.
9 MR. MARSHALL: Exactly. Darrin Marshall, project
10 manager, FortisBC. On the UBO project in particular,
11 we advanced the schedule in order to give ourselves
12 more time to address certain risks, and so when we
13 originally set out in the application, the schedule, I
14 believe, was from March to November of 2018. The new
15 schedule for Unit 4 is now February to September.
16 MS. WORTH: Mm-hmm.
17 MR. MARSHALL: And so what that allows us to do is, a
18 couple of additional months of schedule contingency,
19 in case the embedded components -- the condition of
20 those embedded components, which we don't know of yet,
21 are worse than anticipated.
22 MS. WORTH: Okay. And then are you able to speak to the
23 advancement at Ruckles?
24 MR. MARSHALL: Yes, I am. The advancement of Ruckles,
25 again, it's to allow greater flexibility in terms of
26 schedule. It's to address that risk, significant

1 risks, with the Ruckles project. And so that -- what
2 the advancement does is, it allows us to simply add
3 schedule contingency.
4 MS. WORTH: Okay, thank you.
5 MR. MARSHALL: Thank you.
6 MS. BURETTA: Hi. Atalla Buretta, BCUC. In response to
7 CEC's IR 1.8.1, SBC provided a list of projects that
8 were re-prioritized from previous years, including
9 their previously-scheduled dates and classifications.
10 For each of the projects, can you explain what the
11 pressures were which caused the deferral?
12 MR. CHERNIKHOWSKY: Sure. Again, it goes back to some of
13 the factors that I talked about previously, when we
14 were now re-estimating projects, we were finding
15 purchases -- again, from the U.S. -- were higher. I'd
16 also go back to improved level of scope definitions.
17 And what I'm referring to when I say that is, we have
18 two ongoing sustainment programs. One of them is our
19 condition assessment program. So we go out on a
20 yearly basis and we visit one-eighth of our
21 transmission and distribution infrastructure every
22 year, and we conduct what's called a "test and treat"
23 and a condition assessment program.
24 And that's where we actually verify in
25 detail the condition of our poles and wires assets.
26 And that's used to identify the detailed scope for the

following year of work.

And as I said, we visit one-eighth of the system. We do it on an eight-year cycle.

So the problem, of course, becomes when we're trying to forecast future levels of expenditures, you have to make some assumptions on what the condition of the assets will be in future years, but you won't know with certainty until you actually conduct the condition assessment. And so we base that on -- those future years forecasts are based on historical levels of work. But it will vary, depending on which feeder, it depends on which area of the system you're working in, and so when you go out there you may find that the actual level of work is higher than you expected.

And so what we were finding is that there was increased scope and therefore costs required. And so again to stay within the formula-allowed amount, we chose to re-prioritize some of the work that could be left until later into future years.

MS. BURETTA: Okay, thanks.

MR. HOBBS: If I may. Robert Hobbs, ICG. Regarding Ruckles, it appears in your application that you tendered the electrical package, and yet later you indicate that most of the electrical work, or design work, was done by FortisBC staff. Can you explain the

1 apparent inconsistency?
2 MR. MARSHALL: On the Ruckles -- sorry, Darrin Marshall,
3 FortisBC. On the Ruckles design portion, you're
4 speaking specifically?
5 MR. HOBBS: Yeah.
6 MR. MARSHALL: The civil and physical work --
7 MR. HOBBS: I was speaking about the electrical.
8 MR. MARSHALL: No, I realize, but I just want to clarify,
9 the resourcing for engineering is the civil and
10 physical was completed by external consultants, but
11 the electrical was completed in-house.
12 **Proceeding Time: 10:11 a.m. T15**
13 MR. HOBBS: And then you tendered it?
14 MR. MARSHALL: No, we tendered the construction work.
15 MR. HOBBS: But not the electrical?
16 MR. MARSHALL: No, the electrical was tendered. It was
17 turnkey. The civil, physical electrical construction
18 was tendered, and awarded.
19 MR. HOBBS: How many quotes did you get?
20 MR. MARSHALL: Sorry, in the tender for the construction?
21 MR. HOBBS: Yes.
22 MR. MARSHALL: I believe we tendered to four. We invited
23 four parties, and I believe two parties declined to
24 bid, and we received -- so we received two.
25 MR. HOBBS: Okay.
26 MR. CHERNIKHOWSKY: Yes, Commissioner?

COMMISSIONER EVERETT: Bill Everett, commissioner. You say -- I'm not an accountant, so I apologize if this is a stupid question, but I'm going to ask it in any event. If you budget in one year for a bunch of capital expenditures, and then you decide to reprioritize, so you push some of them off into the future, when you get to the end of that year, you haven't spent some of that capital budget. So, you must have more cash in Fortis. What happens to that cash?

MR. CHERNIKHOWSKY: I'm not quite sure that it is reflective of the way you've characterized it. So, what happens is as we go through the year, and again Darrin may be able to clarify what I'm saying here. But as we go through the year, we update our capital forecasts on a monthly basis. And so early on in the year, for example, we may find that our forecast, our year-end projection is exceeding the capital formula. And so we would look early on to see what projects could be reprioritized to reduce the total expenditure down to the formula amount. As we go through the year, we continue to make those adjustments. In the end, we still would be targeting to hit the formula.

COMMISSIONER EVERETT: So, even though you reprioritize and don't do a particular capital project that you budgeted for, you somehow end up spending the capital

1 budget amount on something else?
2 MS. MARTIN: Joyce Martin, for FortisBC. If I could just
3 clarify. When we're talking about budgets they are
4 two different things if we're talking about what is
5 actually coming to us through rates. So the amount of
6 cash that we're gaining from customer rates is
7 actually set only on the formula amount. So, we don't
8 include any of the over-expenditure that we -- we
9 anticipate now that we may spend more than the formula
10 amount in 2018. However, what's included in 2018
11 rates is only based on the allowed capital amount.
12 COMMISSIONER EVERETT: Yeah, I'm sorry, as I say, I'm not
13 an accountant. I just wondered, if you budget for
14 something, reprioritize it into subsequent years, you
15 get into your account the money that you were supposed
16 to spend on the stuff you reprioritized. My question
17 is, if that is correct, what happens to that money?
18 MR. HENDERSON: Yeah, its Brett Henderson here, from
19 FortisBC with regards to if there is a -- you know,
20 FortisBC is not sitting on incremental cash. We are
21 forecasting our lines of credit to finance the
22 forecasted rate base. So, if expenditures in theory
23 were lower, there would be lower credit facility draws
24 resulting in lower interest expense, and that lower
25 interest expense would be flowed back to customers in
26 the subsequent year through the flow-through

1 mechanism. So, there is not excess cash that we're
2 sitting on or anything.
3 COMMISSIONER EVERETT: Well, as I say, I'm not an
4 accountant, and I thank you for your answer. I don't
5 understand it, because I'm not an accountant. But I
6 just wanted to -- I think you're telling me, no, there
7 is no excess cash, which is the question I was trying
8 to get to, so I'm sorry for wandering off in that
9 direction.
10 MR. HENDERSON: Correct, we're trying to actually not sit
11 on a lot of incremental cash. We're trying to -- you
12 know, that would demonstrate that you're not using it
13 to finance your rate base. So again, if it was
14 lower, it would be the financing costs on that excess
15 cash would be refunded back to customers in the
16 subsequent year.
17 MS. MARTIN: Joyce Martin again, I don't know want to
18 belabor this, I just want to make the distinction that
19 there is a difference between our internal capital
20 budgets, and the amount of revenue that we actually
21 have imbedded in the rates, which only assumes that we
22 are going to spend to the level of the capital
23 formula. So, anything that we spend that exceeds the
24 capital formula has to be financed internally, and
25 that is all trued up in future years whether it's
26 higher or lower than the original expectation.

Proceeding Time: 10:17 a.m. T16

MR. LOVE: It's Alex Love here with Nelson Hydro and BCMU. So the question that came up for us is, looking at the formula capital expenditures, 2017 in particular, the projected is much higher than the formula, but we understand that's at least in part because projects are advanced from 2018 to 2017. Does it follow, then, that the 2018 projected would be quite a lot less than the formula?

MR. CHERNIKHOWSKY: In this case it's not likely, because there is still some reprioritized work from '14, '15 and '16 that's not being executed in '17 that still needs to be done in '18. So we do except to be above formula in 2018 as well.

MS. ROY: Diane Roy, here. Just to clarify, I wasn’t sure if it was clear earlier in the discussion that the projects that were being discussed are not in the formula, so the Ruckles and the UBO are not in the formula. So when we talked about advancing those capital expenditures, that's not reflected in these numbers here because those are flow-through outside of the formula. So the fact that those are being advanced will not affect the numbers that you're seeing on this slide. So just to make sure we're clear on that.

MR. LOVE: Okay. So then it looks like the actuals and

1 projected are coming in above formula on a consistent
2 basis?
3 MS. ROY: Yes, that's correct.
4 MR. CHERNIKHOWSKY: So I do just want to offer a bit of a
5 clarification with respect to Mr. Weafer's comments
6 earlier before with respect to that it's difficult to
7 forecast capital. And I would argue that I think
8 FortisBC, we do -- we have a good record of being able
9 to forecast capital. Where it does become difficult
10 is forecasting capital, certainly, for years that are
11 far out, right? When you're talking about a capital
12 forecast and a scope of work that's three, four, five
13 years out, and that's what we're into right now.
14 And also what Ms. Roy categorized as the
15 lumpy nature rights in the electric utility as well
16 where our sustainment capital expenditures are in the
17 range of 40 to 50 million dollars per year, a single
18 substation upgrade project can easily be $5 million,
19 and so that represents a significant variance.
20 So PBR as a mechanism for capital has been
21 challenging, yes, but I do feel that we do an
22 excellent job of forecasting capital on an ongoing
23 basis.
24 MR. WEAFER: And fair comments, but obviously you picked
25 a five year -- sorry, Chris Weafer, CEC, MEU What I
26 take from that is you're good in the short-term, it's

more difficult in the long-term, so the longer a PBR period, the higher you're at risk for not meeting the capital formula. Is that fair?

MR. CHERNIKHOWSKY: I would agree with that, yes.

MR. WEAFER: Okay. Can I just ask another non-accountant, similar to Mr. Everett's comments? Because one of the things is nobody -- we certainly didn't anticipate the variance in the capital formula to what's occurred and I don’t think anybody did at the beginning.

And so the paranoia does arise for ratepayers in the sense of you've done well on the O&M side, but you've not done so well on the capital side. And where do we get comfort that the overage on capital is not somehow subsidizing the success on O&M? And it's related to the Commissioner's comments around the, for lack of a better term, the sort of "hide the peanut."

Where we're seeing success on O&M, are we being impacted in any way where decisions are being made that are for capital because the same bodies are also involved in O&M and they assist in achieving the O&M goals? So that's just a sort of general concern that from a high level raises a question around the success of PBR.

MS. ROY: Diane Roy. There's two comments I would make

1 and I don't know if they'll fully answer your
2 question, but one of the reasons we did put capital
3 and O&M under the formula was to try to address that,
4 you know, thinking that if only O&M, for example, was
5 under the formula there may be more of an incentive to
6 shift costs from O&M to capital because that would
7 benefit further. So that was one of the reasons that
8 we wanted to keep both O&M and capital under the PBR
9 plan and I still think there's definitely some logic
10 to that.
11 The other item, you know, is that we are
12 required to report on our accounting policy changes
13 during the PBR term. So we have been doing that and
14 we haven't changed any of our accounting policies, for
15 example, that would allow us to, you know, put more
16 items in capital that previously had been in O&M.
17 And I think your third point was about
18 actually just doing more capital work and O&M. Was
19 that the last item you'd raised?
20 MR. WEAFER: No, no. It's really just the significant
21 variance on the capital side and the success on the
22 O&M side raises a paranoia that there -- and I hear
23 what you say about accounting policies, but ultimately
24 we're trying not -- the purpose of PBR is that we're
25 not drilling down and trying to analyze the management
26 and activities of the utility, but we're seeing on one

side, and particularly over a longer-term forecast capital -- it isn't working. And O&M seems to be solid, which is good. But, you know, is there an interplay that we just are unable to drill down and determine in this type of process that that is prejudicial to ratepayers?

Proceeding Time 10:22 a.m. T17

MS. ROY: Yeah. I mean, I don't think that's the case. You know, going back to what we already discussed, O&M is a little easier to control by the utility, and because of that I think we're able to implement some initiatives that, if you think about the initiatives we do implement, most of them have a capital impact, or they increased capital, and they save O&M. Many of them are like that. So those kind of initiatives also will have that effect. And that is not a bad thing for customers over the long -- it's actually a very good thing for customers over the long term, I think, to have those -- the embedded savings that come out of the PBR term.

So I don't know what else I could say to that.

MR. WEAFER: Well, and that's -- we agree.

MS. ROY: Yeah.

MR. WEAFER: In terms of capital. We don't want you not spending capital which is in the interests of the

1 customers on the O&M side but if it's being deferred
2 till later on in the period, and then the benefits are
3 being extended to further out, that's not a good
4 thing. So, again, these are philosophical challenges
5 with PBR that we're not going to resolve today.
6 MS. ROY: Yeah.
7 MR. WEAFER: But given how this one has worked and the
8 failure of the capital formula, and yet the success on
9 the O&M side, keeping the rates down, there's still a
10 tension we're trying to wrap our minds around, to be
11 frank.
12 MS. ROY: Right. And we have been very cognizant of the
13 fact that there was concern going into this PBR that
14 the company would defer capital to outside of the PBR
15 term. And so we've been very conscious of making sure
16 that we are doing all the capital that we need to do
17 to kind of manage the business and stay safe within --
18 you know, keep our system safe and reliable within the
19 terms. So that is something that we've taken from the
20 last PBR where there was significant concerns about
21 deferring capital. So we've been very clear in
22 addressing that.
23 MR. WEAFER: Yes. It's now reprioritization is we're
24 seeing more of, and just understanding whether things
25 that are being deferred are really in the interests of
26 ratepayers to be deferred. So the issue is still

there. Again, we're trying not to -- the purpose of PBR is not to try and micro-manage, but we come into these proceedings and we see decisions that are being made, and they potentially impact the earnings sharing, and impact on ratepayers. So again, we're not going to solve these issues today, but they're certainly live issues.

MS. ROY: These are things we need to consider for the next plan, yes.

MR. WEAFER: Yeah.

MR. CHERNIKHOWSKY: But I will add just a little bit there, and I discussed this a bit in the FEI hearing, that again PBR has not fundamentally changed the way we plan, operate, and maintain our system, right? Our mandate is to safely and reliably deliver electricity to our customers at the lowest reasonable cost. That is still true. All that PBR did is, it gave us a financial incentive mechanism perhaps to find efficiencies and to reduce the capital expenditures. But in the end, the work that we identify to ensure safety and reliability still needs to get done, and we're still carrying that out the same as we would have previously.

So even if we were in cost of service, for example, and we were seeing these cost pressures, we would still be having these internal debates of, does

the project qualify for re-prioritization or not?

So, in this case, has PBR affected when the capital work is required? I would argue no.

MS. RHODES: Janet Rhodes, CEC. I guess the issue isn't really whether or not you were good at forecasting your capital, it's whether or not the formula forecasts the capital well. I know in FEI there is an issue between the service line additions versus the riser costs. So I was wondering if there is anything along those same lines that's impacting the formula.

MR. CHERNIKHOWSKY: There is an analogue in the electric world. We did see some cost pressures in our growth area, where we have customers that were changing the level of service that they were taking from FortisBC. So they were previously what we refer to as single-phase customers, and they were going to three-phase service.

Proceeding Time: 10:27 a.m. T18

So they were basically taking higher capacity from the company, but not adding any new customers, so they wouldn’t get reflected in the customer growth formula, but they were a capital expenditure that we were still having to incur. And so that is semi-analogous to what was occurring in FEI as well, yes.

MS. RHODES: Thank you.

THE CHAIRPERSON: At this juncture, if there are no other questions, it is now 10:30 and -- Yes, Mr. Hobbs, one question please.

MR. HOBBS: I did have a few questions, thank you, regarding the system losses study. This may or may not be the right time, I'm happy to address those later.

THE CHAIRPERSON: Could we save that question until after we come back and respond to it then?

MR. HOBBS: Sure.

THE CHAIRPERSON: Okay. So, we will take a break until 10:45.

(PROCEEDINGS ADJOURNED AT 10:28 A.M.)

(PROCEEDINGS RESUMED AT 10:51 A.M.) **T20**

THE CHAIRPERSON: So, Mr. Chernikhowsky, you morphed into Mr. Marshall I see. Yes, Ms. Roy, did you want to --

MS. ROY: Yes, thank you. I just wanted to say that we're going to finish off our capital section next, and Darrin Marshall will be speaking to that. I do acknowledge Mr. Hobbs had a question regarding system losses. But none of the speakers that are coming up for the next while will be able to speak to that, so if you wouldn’t mind asking that at the end in our question period, we'll get someone to answer you at that time. Okay? Thank you.

MR. HOBBS: Okay, thank you.

MR. MARSHALL: Hello, everybody, my name is Darrin Marshall and I'm a project manager at FortisBC. And I'm here today to share with you what efforts FortisBC is making towards achieving cost efficiencies on capital work.

In order to become more efficient in executing capital expenditures, FortisBC is largely focused on three areas. These are economies of scope, economies of scale, and risk management.

Economies of scope result from producing complimentary goods, or from completing complimentary activities. The project management office of FortisBC Electric and Energy, have been working together to share project management best practices, which result in safer, more efficient execution of the work. Economies of scale, most of us are aware of. These are cost advantages that arise from an increased output. So, for FortisBC, the economies of scale result from combining work or bundling, and work itself or the supply of equipment or material. And lastly, risk management. And risk management is about reducing the probability of a risk event occurring, and/or the impact should that risk occur.

So, consider the following examples. In 2016, FortisBC combined three transmission rehab projects in the Kootenay region. As a result of this

combination, we reduced the construction labour down approximately $310,000 or approximately 45 percent. Similarly, in 2017, FortisBC utilized a similar strategy on two transmission lines, one in the south Okanagan, and one in the Kootenay region. As a result of combining these two lines, we were able to reduce the construction labour by $125,000, or 22 percent. It is evident that bundling or combining work carries significant value for FortisBC and its customers.

I'd also like to share the following example regarding FortisBC's distribution condition assessment program, as it shows the benefits of leveraging the predictability offered by PBR. In 2016, FortisBC was presented with an opportunity to seek proposals from vendors for their distribution condition assessment program for a three-year period spanning from 2017 to 2019. Following the RFP process, FortisBC entered into an agreement with one of its contractors for the three-year period. In addition, the agreement included two one-year optional extensions for 2020 and 2021. By providing the contractor with a multi-year commitment, the contractor was willing to make investments that it would not otherwise had. This resulted in annual savings of approximately $300,000, or 25 percent annually, until the end of the PBR period, and

1 potentially into 2021 on whether or not those optional
2 extensions are taken.
3 In summary, FortisBC has pursued three
4 avenues in order to achieve cost efficiencies on
5 capital work. These are economies of scope, economies
6 of scale, and risk management. Furthermore, FortisBC
7 has leveraged the predictability, and the flexibility
8 afforded by PBR in order to achieve greater cost
9 efficiencies. Thank you very much for your time
10 today, and I'm now willing to take any questions that
11 you may have.
12 **Proceeding Time 10:56 a.m. T21**
13 MS. WORTH: Leigha Worth on behalf of BCOAPO. We have
14 sort of briefly talked about the Ruckles and UBO
15 reprioritization, where you brought forward those
16 projects. You cited risk as the reason that you
17 wanted that additional time, in order to deal with
18 those two projects.
19 And I was wondering if FEC has changed how
20 it actually assesses risk, or if there was a
21 significant enough change in the perceived condition
22 of those two that changed how FEC assessed the risks
23 associated with those.
24 MR. MARSHALL: No. We haven't changed how we manage our
25 risk. The conditions of some components are still
26 unknown. And given we have the capability of

1 advancing the schedule by approximately one month, we
2 thought that it was prudent to do so.
3 MS. WORTH: Okay. Thank you.
4 MR. MARSHALL: You're welcome.
5 MS. RHODES: Janet Rhodes with the CEC. You mentioned
6 bundling.
7 MR. MARSHALL: Yes.
8 MS. RHODES: And you have a multi-year commitment to the
9 end of PBR?
10 MR. MARSHALL: Yes.
11 MS. RHODES: So is that -- did you select the end of PBR
12 because it was the end of PBR, or because of another
13 reason, to do that? And would we have had more
14 savings if you'd gone on the longer time-frame?
15 MR. MARSHALL: Again, yes, we did choose 2019 as the
16 ending period, because of the predictability offered
17 by PBR. We do have the optional two one-year
18 extensions, and the prices are held for that as well.
19 So I don't see, if we had gone past 2021, eventually
20 there's a bit of uncertainty in the labour market, and
21 contractors would then pay -- require a premium in
22 order to cover that risk.
23 MS. RHODES: So if I'm hearing you right, by selecting
24 2019, we didn't lose anything.
25 MR. MARSHALL: No.
26 MS. RHODES: We didn't reduce our savings that we

otherwise would have had if you'd gone through to 2021 now.

MR. MARSHALL: Sorry, could you rephrase your question? I'm just having a hard time hearing.

MS. RHODES: By your selecting 2019 --

MR. MARSHALL: Yeah.

MS. RHODES: -- we didn't reduce any savings that we would otherwise have had, because you have kept the option through to 2021? Is that correct?

MR. MARSHALL: That's correct.

MS. RHODES: Thank you.

MS. ROSS: Laurel Ross, Commission staff. I have another question on capital expenditures. It's probably more related to the last presentation, so I'm not sure if now is a good time to ask. But it just relates to the response to BCUC IR 11.1.1?

And there is a table provided that showed the 2017 capital expenditures broken down into mandatory and essential expenditures. And it listed them by category. And so the three most significant categories in terms of expenditures were new connects; transmission and station sustainment; and distribution sustainment. And I'm wondering if somebody can speak to any specific factors or projects that are driving the need for the expenditures in those three categories?

1 MR. MARSHALL: Paul, did you want to take this one?
2 MR. CHERNIKHOWSKY: Yes. So it's Paul Chernikhowsky,
3 FortisBC. The new connects category is fairly
4 straightforward. Again, customers that qualify under
5 our extension tariff, we consider that mandatory. We
6 have an obligation to serve customers.
7 The individual projects that are making up
8 the transmission and station sustainment and
9 distribution sustainment categories, I would call that
10 -- essentially it's the core work that we do as a
11 utility, ensuring that our assets are safe and
12 reliable.
13 I don't have the detailed list of the
14 projects right now. We would have to probably take
15 that as an undertaking. But I would say that they
16 are, again, typical projects that we'd be doing on an
17 annual basis.
18 One additional clarification that I'd
19 offer, and we've discussed this in some of the IRs, is
20 that work tends to move from category to category over
21 time. So a project, for example, that may be flexible
22 in one year, the longer you wait, it becomes
23 essential. And an essential project that has some --
24 still some flexibility to it eventually becomes
25 mandatory, from the point of view of it now presents a
26 more immediate safety reliability impact. So some

1 projects that would have previously been essential
2 would've been included in that mandatory category for
3 that reason.
4 **Proceeding Time: 11:00 a.m. T22**
5 MS. ROSS: Thank you.
6 MS. RHODES: One more question. Janet Rhodes with the
7 CEC. One more question. Your bundling of work, is
8 that all capital within the formula or do you also do
9 that with flow-through capital?
10 MR. MARSHALL: Capital within the formula.
11 MS. RHODES: Thank you.
12 MR. GEISSLER: Ben Geissler with Nelson Hydro. I just
13 had a question about your bundling. Are those all
14 projects that were planned for 2016, but done
15 independently? Or were they from the future capital
16 that were pulled into 2016 to be done at once all
17 together?
18 MR. MARSHALL: Is your question some of the bundling,
19 does that include reprioritized work?
20 MR. GEISSLER: Yeah. So was some of that capital in
21 2017/2018, and then you pulled into 2016? Or were all
22 those projects initially planned to be done in 2016,
23 but separately?
24 MR. MARSHALL: I'd have to go back and review the lines,
25 but in 2016 I can confirm that they were either lines
26 that were planned for 2016 or had been reprioritized

from 2014 or '15.

MR. GEISSLER: Okay.

MR. MARSHALL: They would not pull forward.

MR. GEISSLER: Okay.

MR. MARSHALL: And then in 2017, the same comment. I'd have to go back and double check, but, again, there was no transmission lines pulled forward, it was simply lines that had been reprioritized from past years.

MR. GEISSLER: Thank you.

MR. MARSHALL: Alex?

MR. LOVE: Alex Love, Nelson Hydro and BCMEU. I wondered if you could just speak sort of as a general comment, in terms of capital construction. Is Fortis more constrained for funds, dollars, or constrained by resources to execute the capital projects?

MR. MARSHALL: I wouldn’t say that we're constrained. I mean, talking about funds I think Paul has covered off some of the pressures that we've faced, but certainly we haven’t had any constraints on the resourcing side. Does that adequately answer your question, Alex? Maybe I'm misunderstanding?

MR. LOVE: Yeah, so I think you're saying that if something else presented itself you have capacity to take it on?

MR. MARSHALL: Certainly we do. Yeah.

Shawn?

MR. FILICZ: Shawn Filicz, city of Penticton Electric Utility. Probably two questions, one for Darrin and then one for Paul. Regarding bundling of work, on your Ruckles substation and on the city of Penticton's RGA Carmi Substation, was there an opportunity there to sort of bundle those two projects and economies of scale gained by ordering two transformers and cost savings there that could --?

MR. MARSHALL: No, given the schedules for the projects, we were unable to do so.

MR. FILICZ: Okay. Okay. So then, Paul, my question, then, might be to somebody else. It's really around — and I know we asked an IR around it — contributions in aid of construction. So when you're talk about new service expansions or in the case of our substation, there's quite often 100 percent of the cost paid upfront by the customer, so I'm a little -- somewhat a little confused bit around how that gets handled. Because from a capital standpoint in essence you're receiving cash from the customer to cover 100 percent of the capital costs, but yet it still falls outside the ban.

So I'm --

MS. MARTIN: The PBR plan doesn't actually change the accounting practice for customer-driven projects.

1 What happened when a customer pays for improvement or
2 for work on FBC's assets, and this includes, for
3 example, even a residential customer who has to pay a
4 portion of their extension policy, the gross total
5 cost for FBC to do that construction work gets added
6 to rate base by way of planting service. So the value
7 of our gross assets increases and then there is a line
8 item in the rate base calculation which is
9 contributions in aid of construction, which is a
10 reduction against the rate base.
11 **Proceeding Time: 11:05 a.m. T23**
12 So, actually the net amount that goes to
13 rate base, and the net amount that the ratepayers pay
14 for through revenue requirements is the net of the
15 two. So, the gross contribution less the customer.
16 The gross construction, rather, less the customer
17 contribution.
18 So, the issue that we have when we talk
19 about the treatment of it in PBR for between the two
20 utilities, is that on the gas side, the amount that is
21 included in the formula, and that gets escalated by
22 the inflation factors every year is that net amount.
23 On the electric side, we didn’t set the formula that
24 way. So the formula has to account for all of the
25 cost of doing the construction. And even though the
26 rate base gets reduced, the rate impact of it is not

1 different. It is just that it eats up more of the
2 formula capital because we didn't have that reduction
3 included in the capital.
4 MR. FILICZ: Okay, so just for clarity, I think what I'm
5 hearing is the gross amount gets reflected. And I'm
6 looking at slide 15 here where you have the various
7 years and the projected formula variance amounts. So
8 in 2017 where it says formula capital you're saying
9 the gross amount gets captured, but not the net amount
10 in this amount --
11 MS. MARTIN: That's correct.
12 MR. FILICZ: -- even though you're recovering full
13 recovery, potentially, or a significant portion, but
14 the formula itself just doesn't recognize that?
15 MS. MARTIN: Yeah, if we had set the formula the other
16 way, then we would be able to use that customer
17 contribution in order to account for additional work
18 on the FPC, on the utility's side.
19 MR. FILICZ: Okay, so to the Commissioner's comment
20 before, so you're receiving the cash, the cash is in
21 your bank account, but the formula itself shows that
22 you're, for lack of a better term, under recovering,
23 but yet you are recovering, so it's -- okay, I think I
24 understand why it is confusing. Okay.
25 MS. MARTIN: Yeah, it is a bit inconsistent in that it
26 would perhaps make more sense to have the formula

account only for the funds that the company had to contribute.

MR. FILICZ: Thank you.

MR. WEAFER: Just a follow up. Can you refresh why it was dealt differently for gas than electric in terms of customers' contribution in aid of construction? Why are the formulas different for capital?

MS. MARTIN: I am going to attribute a little bit to the learning curve. On the electric side we hadn't had a capital formula since 2004, and so when we looked at various ways that it might work out for us, we, I guess just didn’t anticipate what all the outcomes were. We were generally considering that our customer extensions were mainly of the, I don’t know, garden variety, being sort of regular residential and commercial customers, and we weren’t thinking in terms of those kind of large customer driven projects that we're seeing on the city of Penticton, and the, some of the forced upgrades and that kind of thing. So, I guess a lesson to be learned that this is perhaps one of the ways in which the formula is not serving us as well as it might.

MR. WEAFER: And by that comment, and this is for the future drafting of the capital formula, the gas approach is better than the electric approach when it comes to dealing with CIAC? Or does the company have

a view?

MS. MARTIN: I guess there is a lot of ways that we're going to have to have a hard look at what we would like to do with the formula and how it might better fit our capital plan. We had some other questions around, you know, what if you split up the growth and the sustainment the way that the gas side does, and that's another thing that we have that single formula instead of the two formulas. So, we do need to take a really hard look at what options we have available to us and what might work best for us in the next iteration of PBR.

MR. WEAFER: Fair enough, thanks.

COMMISSIONER EVERETT: I apologize if this is a bad question again, but customer aid of construction monies --

MS. MARTIN: Yes.

COMMISSIONER EVERETT: -- go into the formulas, I understand it, but they don’t go into the rate base, they're deducted. Or maybe I've got that wrong too. But if it is in the formula, is it then used in the calculation of what gets shared between the shareholders of the company and the ratepayers?

MS. MARTIN: It is not in the formula.

COMMISSIONER EVERETT: Oh, it's not.

MS. MARTIN: That's correct.

1 COMMISSIONER EVERETT: Okay, I misunderstood you. I
2 thought you said it was. Okay, sorry.
3 **Proceeding Time 11:10 a.m. T24**
4 MS. MARTIN: No, the higher, the gross amount is what the
5 formula is based on. The higher amount before the
6 customer makes their contribution to the project.
7 COMMISSIONER EVERETT: Okay.
8 MS. ROY: And, Diane Roy, just to be perfectly clear, I
9 hope. The contributions themselves, so the cash we
10 get in, it's outside the formula and because of that,
11 we forecast how much we're going to collect each year.
12 So for example when we set our 2017 rates, we would
13 have forecast the contributions coming in already. So
14 our rates were set in anticipation of receiving that
15 contribution, so we didn't collect cash, I guess, from
16 other customers, on top of the cash we got from, say,
17 the city of Penticton.
18 Yes, Bill.
19 MR. ANDREWS: Bill Andrews, BCSEA and Sierra Club. If I
20 understood you correctly about the bundling under the
21 PBR, the indication was that you would not have done
22 this bundling under a cost of service approach, is
23 that correct? And if so, can you explain what it is
24 about cost of service that would impede what seems
25 like a fairly straightforward efficiency?
26 MR. MARSHALL: Sure, I can comment on that. In cost of

1 service, we would strive to do this. Under cost of
2 service, typically the transmission rehabs have been
3 on an annual basis. With PBR, what PBR allows us is
4 that certain flexibility that I referred to earlier.
5 And so in order to line up the -- align the
6 construction schedule, we may actually elect to start
7 engineering in the fall of the year prior.
8 So we sort of -- we align construction and
9 work backwards. So we're able to start engineering on
10 a staged approach. And it may not necessarily fall on
11 an annualized basis.
12 So again, to repeat, under cost of service,
13 engineering, procurement, and construction would
14 typically happen in a single year.
15 MR. ANDREWS: And that's because it's typical, is that a
16 require -- is there some problem? If money can be
17 saved by planning for more than a single year, is
18 there any impediment to the cost of service?
19 MR. MARSHALL: The issue is that it is difficult to,
20 under cost of service, it's more difficult to -- let
21 me rephrase.
22 In the past, we've done condition
23 assessment on a single year for all lines. And then
24 the preceding year, we would do the rehab on all those
25 lines. What we're able to do now is, once the
26 condition assessment is done, in order to align the

1 construction schedule of the following year, we may
2 elect to start engineering earlier. In the past, that
3 hasn't -- we haven't been able to do that.
4 MR. CHERNIKHOWSKY: So, Paul Chernikhowsky again. We
5 have availed ourselves of bundling opportunities in
6 the past, even under cost of service. The fundamental
7 difference now under PBR is that previously, at best,
8 we would have had a two-year capital plan. And so
9 we've identified work for two years. But any
10 contracts that we'd enter into would be subject to
11 Commission approval, right, because we wouldn't have
12 had approval of those capital expenditures for future
13 years.
14 Under PBR now, we have a lot more certainty
15 because we have that six-year horizon. Of course,
16 we're not working with the full six years, but we have
17 a longer horizon that we're able to work within. And
18 now once we've identified the capital expenditures and
19 the scope that's required, we're able to go with much
20 more certainty to our contractors and offer them the
21 ability to bid on this work.
22 And as Darrin mentioned earlier, they may
23 actually choose to reorganize their own organizations
24 to bring in resources on the expectation that Fortis
25 is going to be able to provide them work. And we
26 wouldn't have been able to do that in the past.

1 MR. ANDREWS: Because of the requirement for a capital
2 plan approval.
3 MR. CHERNIKHOWSKY: Correct.
4 MR. ANDREWS: Thank you.
5 MR. MARSHALL: If there are no further questions, I'll
6 hand it off to Curtis Klashinsky.
7 MR. KLASHINSKY: Good morning, everyone. My name is
8 Curtis Klashinsky, I'm the manager of assets and
9 compliance, and I'm here today to talk to you about
10 the efforts that are outside the PBR formula, that are
11 driven by the B.C. mandatory reliability program.
12 So I'm going to talk about, or give you an
13 update on, assessment report 8, then we'll be talking
14 about assessment 10, and we'll touch on the 2018
15 audit.
16 **Proceeding Time 11:15 a.m. T25**
17 So just to recap the Z factor criteria,
18 costs must be attributable entirely to events outside
19 the control of the utility. Costs must be directly
20 related to the exogenous event and clearly outside the
21 original based cost. Impact of the event is
22 unforeseen. Costs must be currently incurred. And
23 costs related to exogenous event must exceed the
24 materiality threshold.
25 So during the course of the PBR we've hit
26 four assessment reports, Assessment Reports 7, 8, 9

and 10. Assessment Reports 7 and 9 did not meet the materiality threshold, so they were absorbed under the PBR formula values. AR8 and 10 qualify for Z factor treatment. So AR8 was approved as a Z factor for 2016-17 and we're requesting a continuation of that treatment again this year.

We're also requesting a Z factor treatment for Assessment Report 10 as the overall cost will be well above the materiality threshold. I'll be speaking to AR10 in a couple more slides, but our preliminary high level estimate at this point is in the neighbourhood of $3.3 million for one-time effort.

So to touch on Assessment Report 8, 2017 we're completing the capital infrastructure and the operation and planning work. 2018 is going to look at the completion of our transition to Version 5. We're going to be implementing repetitive task, process changes, annual training and the like. 2018 is really the effort that we need to maintain compliance for Assessment Report 8, so the effort we need to do in 2018 is going to be the same for 2019, '20, '21 and so on, at least until the standards change again.

2018 is also going to see the first start of sustaining capital expenditures to support the installed hardware and software from 2017. These costs are typical of any IS system that’s installed as

they approach the end of their life, which in the IS world is five years.

So to touch on Assessment Report 10, it was adopted in July of 2017 this year and has increased operation and planning requirements. The standards adopted have varying times of effective dates but the larger impact ones that we have to deal with are effective in October of 2020. So I've listed here some of the big items that we have to deal with. We need to implement real-time contingency analysis software and analysis processes at least every 30 minutes. So what that means, we have to take a snapshot of our SCADA network, our network, do N minus 1 criteria on it, basically taking an element out of service, see if there's any issues, put it back in, and go around to the next one, so on and so on and so on. If there are any issues the operators need to be identified and then they have to address those issues, and then you repeat that process 30 minutes later.

The other thing we're going to need to do is we're going to need to perform and document and communicate system studies every day for 365 days a year, similar to the real-time contingency analysis. It's called operation planning analysis which deal with next day studies. So that means you have to take your current situation, apply your outages, apply your

next day outages, gather information from the neighbouring entities that might impact you, run your study under N minus 1 criteria, take one element in and out of service to see if there are any issues. If there are, you need to document those and provide a written plan and then you need to communicate that plan to the other groups. And in the event if later in the day an unplanned event occurs where an element comes out of service for multiple days, you're going to have to rerun those studies and reissue all that information.

We also need to follow the reliability coordinator outage coordination requirements and process. It's a 68-page document that we're going to have to be going through to determine how we're going to integrate into what their needs are. And we're also going to be looking at backup software, methods in the event of primary software and process failures.

So as I said, like, these things we don't do today. We're also going to need to be looking at what type of resource is required to execute and support these type of functions.

Proceeding Time 11:19 a.m. T26

So in terms of executing Assessment Report 10, we have three years for the big ticket items so it's very similar to CIP Version 5. The first year is

not only to achieve compliance with the standards coming into effect that particular year but we're also going to identify and analyze options for the remaining standards, and identify associated costs with that. So with that, we're going to evaluate software options where we can. We're going to be reaching out to other utilities in the U.S., find out what their interpretation of these standards are, how they're applying them, and we're also going to be watching the audits in the U.S. to help see if the auditor's interpretation matched these utilities' interpretations.

So in 2019 is an execution of the selected options we're going to come up with, rolling into full compliance with AR-10 standards by October of 2020. So as I said, our preliminary estimate of a one-time cost in the neighbourhood of $3.3 million, that's from our assessment 10 report that we provided back in May. But for 2018 we're going to be spending about 0.18 million, primarily in an evaluation phase to look at the verious options and costs associated with those options.

MS. WORTH: Excuse me, just a quick question here.

MR. KLASHINSKY: Yes.

MS. WORTH: I was wondering how much of that $3.3 million is O&M and how much is actually capital costs.

MR. KLASHINSKY: I don't know the breakdown. We don't have that breakdown. But we do know there's going to be a certain amount of software purchases and installs as well as O&M effort. When you do the assessment report, they look at what does it take to become compliant, and then the costs and effort after compliance. There's no capital O&M breakdown.

2018 will -- when we do the evaluation, the detailed option, we'll be breaking that out accordingly.

MS. WORTH: Okay. And can you clarify the time frame over which the costs are spread? You know, what are the likely annual values?

MR. KLASHINSKY: We looked at the ongoing costs back when we did the assessment report, it was looking in the neighbourhood of $2.8 million.

MS. WORTH: $2.8, okay. And I was wondering, too, just because we're talking about the threshold regarding the exclusion from the formula, I just wanted to clarify. Does FBC actually see the threshold applying to the annual or the total expenditures for these?

MR. KLASHINSKY: We see it applying to the event. And AR-10 is the event.

MS. WORTH: Okay. So, you're indicating presumably then it would be to the annual expenditures? Or --

MR. KLASHINSKY: The total.

1 MS. WORTH: The total, okay. Thank you.
2 MR. GEISSLER: It's Dan with Nelson Hydro again. Just a
3 clarification. This might sound ignorant, but is
4 FortisBC complying with the previous version of CIP
5 standards? Like, CIP version 3?
6 MR. KLASHINSKY: Yes.
7 MR. GEISSLER: Okay. So, these are all changes that are
8 required between differences between version 3 to
9 version 5.
10 MR. KLASHINSKY: Not for assessment report 8, but for
11 assessment report -- or, not for assessment report 10,
12 but for assessment report 8, yes.
13 MR. GEISSLER: Okay, thanks.
14 MR. KLASHINSKY: Assessment report 10 is really things
15 that came out of the South California outage back in
16 September, 2011. They identified a variety of things
17 where their transmission operators were not really
18 fully looking at their system, or communicating with
19 others, and that type of thing. So a lot of these
20 requirements now apply to all transmission operators.
21 So --
22 So 2018 is another audit year for us. It's
23 our third triennial compliance audit. The
24 implementation plan, typically comes out late October,
25 early November, and that really defines your timelines
26 and scope of your next year audit. Typically audit

times, three months before they come on site you get notification. It takes a couple of months to gather the information and evidence, pull it all together, submit it. There are some questions that go back and forth. Then they come on site, they do site inspections, interviews, do some final clarifications before they close the audit.

So the MRS audit costs are non-reoccurring, and are not included in the formula O&M, and we're forecasting those costs to be incremental of $0.35 million.

MS. WORTH: Leigha Worth again for BCOAPO. I just had a follow-up question, sorry. I looked at the answer that you gave me regarding the $3.3 million. You actually indicated $2.8 million per year, which is the ongoing cost associated with the -- sorry, the 2010 -- or assessment report 10. And actually what I was wondering was, is the $3.3 million going to be spent within one year or is that cost going to be spread out over a number of years?

Proceeding Time 11:24 a.m. T27

MR. KLASHINSKY: Well, at this time the high-level estimate is 3.3. But that's basically to take us from today to October 1st, 2020.

MS. WORTH: Okay.

MR. KLASHINSKY: And then after 2020 the high-level

1 estimate this time is 2.8.
2 MS. WORTH: Okay. And do you have an estimate on how
3 that 3.3 million is going to be distributed in the
4 interim between now and October 2020?
5 MR. KLASHINSKY: That'll be part of what our 2018
6 analysis is going to be.
7 MS. WORTH: Okay.
8 MR. KLASHINSKY: From what's needed to do in 2019 as well
9 as 2020.
10 MS. WORTH: All right, that's very helpful, thank you.
11 MS. RHODES: Janet Rhodes with the CEC. I see the
12 forecast cost for the MRS audit is 0.35 million, and
13 that's not substantially higher than their materiality
14 threshold. So what happens if the costs come at 3.0
15 million? .30 million, sorry.
16 MR. KLASHINSKY: Well, audit costs are not part of the Z
17 factor treatment. They're actually a non-reoccurring
18 cost as identified in the decision back in 2014.
19 They're non-reoccurring therefore they're outside the
20 formula.
21 MS. RHODES: Thank you.
22 MS. MARTIN: Sorry, and just to clarify, because they're
23 outside the formula they're asked to trued up every
24 year. So if they come in less, then that would be
25 returned in the following year.
26 MS. RHODES: Thank you.

1 MR. WEAFER: This is Chris Weafer from the CEC. Just
2 following up on Dan's question just to make sure I
3 understood the response, the changes in MRS date back
4 to events that occurred in 2011. Was that the answer?
5 MR. KLASHINSKY: Yes. Ultimately.
6 MR. WEAFER: So in terms of Z factor criteria, the impact
7 of the events unforeseen, wouldn't that have been a
8 foreseen event when we entered into the PBR period?
9 MR. KLASHINSKY: So the way the process went is the event
10 occurred in September. The U.S. federal department
11 did their analysis. Then they did some
12 recommendations. Then those recommendations were,
13 I'll say, created through the standards, vetted
14 through the standards, through the whole standard
15 application process or the whole multi-year thing, up
16 until they actually finally decided that yes, this is
17 what we are going to approve. It's really unknown as
18 to what direction it goes.
19 MS. MARTIN: Joyce Martin here. Just to clarify, Chris,
20 the event that is driving the Z factor is the
21 acceptance of those standards by the BCUC for
22 applicability in British Columbia and not -- what
23 Curtis was referring to was a system grid event that
24 occurred in California in 2011 which drove the U.S.
25 regulators to modify the standards.
26 MR. WEAFER: And so just refresh. When did the BCUC

adopt the standards?

MS. MARTIN: Earlier this year in September, is that right?

MR. KLASHINSKY: End of July of 2017.

MR. WEAFER: Okay, thank you.

MR. HOBBS: Robert Hobbs, ICG. Can I confirm that you're looking for Z factor treatment for the capital portion of your 3.3 million and the O&M portion is not going to be treated in the same manner?

MS. MARTIN: Joyce Martin. No, that's not correct. The event doesn't -- the definition of the Z factor refers only to an event and it doesn't distinguish between capital and O&M costs. And so for example in the 2017 we had a small amount of O&M and a larger amount of capital, unless I have that backwards. And the costs are all aggregated as arising from that event, and it is the event which becomes the Z factor. So there's not a separate event for capital and a separate event for O&M. It is a single event.

MR. HOBBS: And they're both included for treatment as Z factors.

MS. MARTIN: That's right.

MR. HOBBS: Can I take you to ICG 10.2? What does your first sentence in that response mean?

MS. MARTIN: If you're asking why we've referred only to capital in that question it's because the question

itself referred only to capital, so we didn't broaden it to encompass any O&M. So the question was: Identify capital expenditures related to MRS compliance. And we propose Z factor treatment for all such capital expenditures, and our response was framed in terms of only capital expenditures as well.

Proceeding Time: 11:29 a.m. T28

MR. HOBBS: Thank you.

THE CHAIRPERSON: I have a question. You forecast cost for the next audit at $350,000. What was the cost of the last audit?

MR. KLASHINSKY: The 2015 audit was $375,000.

THE CHAIRPERSON: Okay, thank you.

MR. KLASHINSKY: With that, I'll pass it on. James?

MR. WONG: Good morning, my name is James Wong, my colleagues Suzana Prpic and Michelle Carman will be presenting the SQI results. We will provide the highlights of the SQI performance for 2016 being the most recent full year result, along with the August 2017 year-to-date results. And consistent with that outline in the consensus agreement, we will provide further discussion of the All Injury Frequency Rate as that performance, the metrics performance has had consecutive years of performance below the benchmark. In addition, we'll provide further discussion on the abandon rates and the callback feature.

So, the format of the table includes the 2016 annual results. So, this is consistent with the decision in Order G-44-16 where the Commission determined that it was appropriate to review FBC's service quality in the following year's annual review. There is discussion of this decision on page 125 of the application, and for comparison we've also provided the August 2017 year-to-date results. Next year at the annual review we will provide the final 2017 results for determination whether there is a serious degradation of service.

So, in terms of overall performance, so FBC's 2016 annual results indicate that the company's overall performance is meeting service quality standards. As you can see on the table, for the eight SQIs with benchmarks, seven performed at or better than the approved benchmarks, with the remaining one, the AIFR, performing better than the threshold and within the performance range. For the three metrics that are noted as informational indicators, performance is generally consistent with prior years.

So, in terms of the two groupings or categories of the metrics, responsiveness to customer needs, here is the results for 2016:

The performance of the four responsiveness to customer needs metrics were benchmarks in 2016

indicate that we are continuing to meet service quality standards. For comparison, we have also provided the August 2017 year-to-date results, which is an update to the numbers included in the application, that being results were there to the end of June 2017. And as you note, the August results for 2017 year-to-date are consistent with that provided in the application.

In terms of the category safety and reliability, for the four metrics here with benchmarks, the 2016 performance again indicate the company is continuing to meet service quality standards. For comparison, again we've also provided the August 2017 year-to-date results which is an update to that included in the application being the June 2017 year to date. And of note again is the August results for this year, year to date, are consistent with that included in the application.

With that, I'll pass it on to Suzana to talk specifically about the AIFR.

MS. PRPIC: Thank you, James, and good morning. As noted, my name is Suzana Prpic, and I'm the director of corporate emergency management at FortisBC.

I'll be reviewing the All Injury Frequency Rate which is commonly referred to as the AIFR. As was reviewed in our application, the AIFR is a measure

that includes the combination of loss time injuries and medical treatments. Injuries per 200,000 hours of exposure or in this case, the hour of time spent working. 200,000 hours are the hours worked by 100 employees, averaging 40 hours per week over a 50-week span with two weeks taken away for holidays. If the total hours employees worked is less or more than 200,000 hours it really doesn't matter as this number is used to establish a trending benchmark.

Proceeding Time: 11:34 a.m. T29

With respect to the two types of injuries that I noted, medical treatment injuries are injuries that occur at work and result in a medical practitioner administering treatment such as prescribing medications, stitching cuts, or setting broken bones. This injury does not result in an injured employee missing a full day of work beyond the actual day of the injury.

An injury is classified as a lost time injury when an employee injures his or herself at work and are unable to prolong duties for a minimum of one full day beyond the date of injury. This does not include part days lost or days for which an injured employee is accommodated on modified duties. As per the table on the slide, the FortisBC annual AIFR for 2016 was 1.15. The three-year rolling average was

1.97, which is between the benchmark and the threshold.

We’ve included year-to-date results up to August 2017. Both the annual AIFR and the three-year rolling average are below the benchmark. We're very pleased to announce that the results are trending very positively.

I'll very briefly summarize the nature of the injuries that occurred in 2016. There were five lost time injuries recorded: one related to a tree branch snapping and hurting a worker's knee; one was a rolled ankle experienced while the worker was exiting a vehicle; two injuries were ergonomic or body positioning in nature; and the fifth injury related to an eye irritation.

The corrective actions stemming from these and from all safety investigations are managed through FortisBC's robust safety management system, which addresses risk identification and mitigation requirements, tools used to avoid injury recurrence, and to continually raise awareness about safe work planning.

The company also continues to maintain the certificate of recognition or COR through audits performed annually. These audits provide ongoing validation of the effectiveness of the company's

safety programs. The company maintained a maintenance audit in consideration of this initiative in 2016 and the certificate of recognition was maintained by WorkSafeBC.

As part of the company's ongoing focus on continual improvement and support of our safety management system, FortisBC launched the Target Zero safety program in January of 2016. This program continues to provide a structured format and heightened awareness for all of our employees in order to encourage participation in corporate safety initiatives allowing for the prioritization and implementation of initiatives that are most relevant to employees and the work tasks they conduct each and every day.

Given the positive results and given that Target Zero is the major safety initiative supporting all employees' safety awareness through 2016, and now in 2017, we feel that the program elements being reinforced are positively influencing overall safety performance.

Thank you.

Yes?

MR. QUAIL: I'm sorry. Do I understand correctly that you assume two weeks' vacation when calculating the AI upfront?

1 MS. PRPIC: That is an industry standard that's used in
2 most of North America.
3 MR. QUAIL: But in terms of your own -- the numbers here
4 for FBC's performance?
5 MS. PRPIC: The 200,000 hours is a general standard
6 that's been utilized.
7 MR. QUAIL: Yeah. But I mean the starting vacation
8 entitlement for unionized workers is three weeks, and
9 that's to start and it's like everybody else getting
10 year older every year and people are climbing up in
11 that. So the actual number of hours worked in a year
12 on average is substantially reduced by the fact that
13 vacation entitlement is much greater than you assume,
14 isn't it?
15 MS. PRPIC: Yes, I understand, but it's --
16 MS. MARTIN: Sorry. Sorry, Joyce Martin. I think what's
17 being referred to is that the two weeks assumption is
18 what is causing the -- or the number that results in
19 the denominator, which is the standard. So because
20 you're using an index it's the actual work hours that
21 go into the numerator and it's just divided by an
22 industry standard number of hours. So it doesn't have
23 any, you know, however may hours that are actually
24 worked by employees is what is included in the
25 measure.
26

Proceeding Time 11:38 a.m. T30

1 MR. QUAIL: I'll take your word for that.
2 MS. MARTIN: Yeah. Just in order that all utilities can
3 report on the same standard, they use the same number
4 of hours. So, if you had your 200,000 hours for each
5 utility, then you get a standard measurement. You
6 don't want to divide by a different number and --
7 MR. QUAIL: See if I understand. The number that's here
8 isn't actually the actual depiction of what's
9 happening on the ground in the company, it is an
10 indexed number that's a comparator with other
11 utilities.
12 MS. MARTIN: That's right. You could index to any number
13 you wanted in the denominator.
14 MR. QUAIL: So the actual weighted injuries is something
15 that actually would be greater than that, because
16 there's fewer hours worked than the index assumes.
17 MS. MARTIN: Well, I think what the index assumes is this
18 is kind of a general number of hours that would be
19 worked by 100 employees over the period of a year.
20 So, it's just for consistency and for comparability
21 among utilities.
22 MR. QUAIL: And so what we have here is a comparative
23 score with other utilities but not an actual report on
24 the actual number of incidents of injuries in absolute
25 numbers.
26 MS. MARTIN: No, you still are able to report the actual

number of injuries.

MR. QUAIL: You have a table that has the numbers and describes in general terms what happened. So we have that information.

MS. MARTIN: Yeah, this is just a way of indexing it for comparability, yeah.

MS. ROY: And also comparability within the utility. So it is still comparable between years, for the utility as well. So it is important to have a kind of a standard of reporting there.

MR. LOVE: It's Alex from the Nelson and BCMEU. Just to make sure I understand the index, this is lost time hours per 200,000 hours worked. Is that right?

MS. PRPIC: Lost time injuries and medical treatment injuries.

MR. LOVE: A count of injuries, or a count of hours?

MS. PRPIC: A count of injuries per 200,000 hours worked.

MR. LOVE: Okay, thank you.

MS. PRPIC: Thank you.

MS. CARMAN: Good afternoon. I'm Michelle Carman, the manager of customer operations and contact centre at FortisBC, and today I'm going to be talking to you about a couple of things.

We found we had some questions this year around abandon rates, as well as the Commission directive regarding the call-back feature, and we also

had some questions there.

Now, some of you may have noticed, Diane this morning mentioned in her agenda that I'd be talking about the average speed of answer. So for those of you who are hanging on your seats to hear about the average speed of answer, it's something I can definitely deal with in questions, but I am just going to be chatting about abandon rates and call-back feature right now.

So with respect to our abandon rates, I know we've talked a lot in our application, and IRs over the last couple of years, that there really is no way to tell with certainty why a customer has abandoned a call. And certainly that a reduction or increase in the abandon rate is not necessarily something that is favourable or unfavourable. And this is because abandoned calls can happen for a variety of reasons. You know, think about your own experiences. A customer might call us by accident, realize it's us, hang up. They might have something come up unexpectedly. Right? I've got a four-year-old daughter at home who will start asking me questions and I think, "Okay, there is a better time to make this call."

A customer might also think the relative importance of their call -- you know, the reason that

they're calling, and if we haven't picked up immediately, they might decide to call back later. And finally, which we talked about a lot, is our use of our IVR. So, you know, is there messaging on our IVR that is providing our customers the information that they're looking for?

Proceeding Time: 11:43 a.m. T31

MS. CARMAN: Now certainly we recognize that -- oh, Yes Jim?

MR. QUAIL: You've given a list of different circumstances, and the first ones that you gave strike me as things that wouldn't produce any trend change. It is just something that happened, people dial wrong numbers. Presumably more people aren't dialing the wrong number this year than they did two years ago. So, of the ones you identified, is it correct to say, that the IVR is the only thing really that is a change that could be looked at potentially as producing a trend one way or the other? So the relative importance of people's calls, again, presumably is not something that would shift overall from year to year in your numbers, would it?

MS. CARMAN: Perhaps, but again, I mean I can't say with certainty. Absent being able to immediately call back a customer who has abandoned a call and ask, "Why have you abandoned?" I don't know for sure. We don't know

1 for sure the reasons why or the relative percentages
2 why. So, in terms of understanding trends, perhaps,
3 it might be a reasonable assumption. But I can't say
4 for sure.
5 MR. QUAIL: And the same though, for example we are
6 looking at a trend, a potentially negative trend,
7 wrong numbers cannot be an explanation for that,
8 unless somebody has opened up a pizza chain that has
9 an identical number except for one digit or something
10 like that. But you know what I mean? That presumably
11 those would be relatively constant. So, if we're
12 asking what's changed here, I've only heard one factor
13 that sounds to me like a potential candidate.
14 MS. CARMAN: Okay, fair enough. And to clarify as well,
15 as I mentioned earlier, an increase in the abandoned
16 rate isn’t necessarily a bad thing. So, if we're
17 seeing a trend in an increasing abandoned rate, it
18 doesn’t necessarily mean that it is a bad thing, or an
19 indicator of a reduction in customer satisfaction.
20 So, certainly we recognize that in 2017 and 2016 we
21 have seen a higher than recent year experience in
22 terms of the abandon rates. And so naturally there is
23 going to be questions. So, even if I can't say with
24 certainty why, you know, what is a reasonable best
25 guess to why is this occurring?
26 So, it is just -- Oh, yeah, go ahead?

1 MS. CRAIG: Marg Craig with Nelson Hydro. So, I also
2 want to clarify that with your abandon rates, that's
3 for all your services? This isn't just people calling
4 in during outages. This is for whatever --
5 MS. CARMAN: Yeah, this is of all the calls we've
6 receive, how many customers drop before we actually
7 get a chance to talk to them.
8 So, as we discuss in our responses, we
9 continue to believe that it is reasonable to assume
10 that what is happening in 2016 and 2017 really is
11 related to outages. So, when an outage occurs, to the
12 extent that it makes sense for that outage, we record
13 a message that plays on our IVR. So, if a customer is
14 calling about that outage, and they get the
15 information they need, they hang up without having to
16 actually talk to one of our representatives, and that
17 call is counted as abandoned.
18 Now, as I've mentioned a couple of times,
19 we can't say for certain, but we believe the increase
20 is unlikely related to call wait times. This is
21 because our customers continue to have average wait
22 times of less than a minute, and even though, I can't
23 say why, I can certainly show you when. So, that is
24 what this table here demonstrates. So, this gives us
25 a sense of when our customers are abandoning calls,
26 and helps lead me to the conclusion that wait times

1 perhaps really aren't an issue here.
2 What you can see is the majority of our
3 calls are abandoned before that two minute wait mark.
4 So, if you think, you know, in terms of relative
5 amount of time, one to two minutes really isn't that
6 long in terms of the wait time. And 40 percent of
7 those are actually abandoning prior to that one minute
8 mark. So, it is, you know, we can't say for certain
9 that the abandoned rate is not increasing because of
10 wait times, but all the information that we're seeing
11 here in terms of when customers are abandoning, the
12 things that we're seeing with some of our other
13 metrics in terms of customer satisfaction, aren't
14 leading us to believe that that is what is going on
15 here.
16 Now, that said, there certainly will be
17 customers that abandon due to wait times, and that is
18 part of the reason where we thought the callback
19 features could certainly help. And it also provides
20 options for all of our customers in terms of how they
21 want to reach us, and how we can reach them.
22 So, with respect to that callback feature,
23 the Commission asked last year, that we discuss the
24 impact of the feature on abandon rates, and in
25 particular, identify other potential informational
26 indicators, or measures that may help us understand,

or provide additional value, to understanding perhaps if there is a trend in fact going on here.

Go ahead, Jim.

MR. QUAIL: Just looking at your abandon rates table here. So, if you combine the percentage of abandons in the year to date between 1 to 2 minutes and over 2 minutes, that is about roughly 60 percent.

MS. CARMAN: Yeah.

MR. QUAIL: So, there appears to be a pretty strong correlation between the length of the answer time, and the likelihood of abandoning. It seems pretty straightforward.

MS. CARMAN: What do you mean by that?

MR. QUAIL: Well, your chart shows that of the percentage of abandons year to date, 60 percent of those are people who waited more than a minute. And in fact over 40 percent waited more than two minutes, as opposed to only 13 percent if they were answered between 31, 60 seconds. So, there is a pretty obvious -- you get a 27 percent, you know, almost right away, who knows what is happening there, but beyond that, there is a steady increase in the rate of abandoned just depending on how long somebody is left waiting for an answer. I see in your table there on slide three.

Proceeding Time 11:48 a.m. T32

MS. CARMAN: So a steady increase in terms of -- so we see a smaller percentage in that 30 to 60, a slightly larger percentage in the 60 to 120 --

MR. QUAIL: They get more and more abandoned, and it's sort of intuitive, the longer people are waiting. So the suggestion that it's not related to answer time doesn't seem consistent with the data you provided on slide 30, which appears to show a correlation between speed of answer and abandonment.

MS. CARMAN: But still, relatively overall, right? 40 percent of our customers are only waiting a minute. Or, overall, the average speed of answer is less than minute. We're at 48 seconds. So on average, right? Most of our calls --

MR. QUAIL: An applied average. But obviously that would fluctuate a lot depending on the time of day, and so on.

MS. CARMAN: Yeah, yeah. It fluctuates. Yes.

MR. QUAIL: There's considerable fluctuation. So some people obviously are waiting two minutes, and we don't know how much longer than two minutes, we don't have that data, I don't think, and --

MS. CARMAN: What also might help to understand is, so, on average we get about 400 calls a day, right?

MR. QUAIL: Yes.

MS. CARMAN: So if you think about relative numbers of

number of customers affected, so if we're talking about an abandon rate of 4 percent, that's about 20 customers a day that are calling us and hanging up.

Now, if we assume roughly more than half of those are hanging up before that two-minute wait mark, as I mentioned, which is really not a significant amount of time. Think about your own experiences, right? A significant amount of time to be waiting. We are talking about, you know, ten customers, less than ten customers. Now, the other factors that we're looking at is --

MR. QUAIL: Ten customers in an average day. That's an average --

MS. CARMAN: On average, right. Yeah, yeah, I'm talking average.

MR. QUAIL: You're talking averages. All right.

MS. CARMAN: And so the other things I'm looking at are, are we seeing changes in our customer satisfaction numbers? We're not. You saw the numbers that James put up there, right? We are still meeting our service levels, our first contact resolution, which -- one of the things that we find with customer satisfaction is, it is more closely aligned with resolution of an issue versus the length of time that it takes to get through to us. So we're seeing overall positive indicators of a good level of service.

I'm not disagreeing with you that we're seeing something here that we need to look into, and to make sure that it isn't telling us something that our customers are having trouble with. It's certainly something we want to look into. I just want you to understand the relative magnitude of how it affects the overall service that we're providing.

MR. QUAIL: No, my point is that you appear to be suggesting that it isn't put -- that there is not a correlation necessarily between abandon rates and how long people are on the line.

MS. CARMAN: Okay.

MR. QUAIL: But I'm just pointing out your own data on that slide seems to indicate the opposite, that there is a relation. I might have -- unless I misheard what was said earlier.

MR. BYSTROM: Chris Bystrom. I was going to suggest we could go back a slide. The point is the second bullet. Look there, is that a higher abandon rate in recent years does not appear to be due to long wait times. The proposition wasn't that there was no correlation between the two. We're looking for an explanation for the higher abandon rates in recent years.

MR. QUAIL: I think those are, with respect, two ways of saying the same thing --

1 MR. BYSTROM: No.
2 MR. QUAIL: -- that there is apparently a cause-and-
3 effect relationship between how long somebody is
4 waiting and their likelihood of abandonment. I mean,
5 it seems pretty clear.
6 MR. BYSTROM: One is talking about a trend, and one is
7 talking about a relationship. So I don't think
8 they're too -- the same thing.
9 MR. QUAIL: Well, we can perhaps agree to disagree. This
10 is the evidence that you've provided to us. I'm just
11 saying that there appears to be quite a strong
12 correlation between those. And I'm assuming that
13 there is some cause-and-effect relationship, which
14 seems like a reasonable conclusion to draw.
15 MR. BYSTROM: And we're just talking about the higher
16 abandon rates in recent years, so we're looking for a
17 reason to explain that. And that is an apparent --
18 MR. QUAIL: And you're evidence is you're more likely --
19 and intuitively it makes sense, the longer you're
20 waiting, even if it's, you know, a couple or three
21 minutes, you're more likely to hang up than if your
22 call is answered faster. So it seems to be pretty
23 clear that there's a cause-and-effect relationship
24 between how long you're waiting and averages, as they
25 say, mask what might be going on.
26 MS. CARMAN: I don't actually know what the correlation

1 is, so I haven't looked industry-wide to understand
2 what those numbers are. Because I think about, you
3 know, myself. And to some extent, you get stubborn
4 and you sit and you wait. So I don't know at what
5 point there actually is that correlation. But I
6 definitely see what you're saying here, and I
7 appreciate your comment.
8 THE CHAIRPERSON: So, I'm not a customer of FortisBC,
9 because I don't live in your territory. But IVR, I'm
10 assuming, is Interactive Voice --
11 MS. CARMAN: Response, yeah.
12 THE CHAIRPERSON: -- Response. And so if you have some
13 of that at the front end, if you're providing
14 information for the customer at the front end, that
15 might be 30 seconds or 60 seconds or whatever of
16 information that's being passed to the customer.
17 MS. CARMAN: Yeah.
18 **Proceeding Time 11:54 a.m. T33**
19 THE CHAIRPERSON: And they may or may not get the
20 information they need in that first 30 to 60 seconds.
21 To my mind it almost starts, the wait time starts when
22 you finish getting all that information and then you
23 make a decision as to whether you've got the
24 information or are you going to stay on the line to
25 talk to a live person? Am I correct in that
26 assumption?

1 MS. CARMAN: Yes. Well, the way that we quantify wait
2 time is from the start that a customer enters our
3 queues and quantify, you know, the abandon rate is
4 from the minute that call enters the queue. Now, some
5 utilities actually calculate abandon rate that way.
6 They wait until the customers gets through that menu
7 and officially makes a selection for what type of
8 agent they want to talk to. And then at that point
9 they'll quantify, okay, how many customers drop calls.
10 So they effectively exclude that --
11 THE CHAIRPERSON: So you don't exclude that first
12 portion.
13 MS. CARMAN: We don't exclude that. We include that. So
14 that's where, you know, to some extent that's going to
15 capture those customers that get the information they
16 needed from the IVR. So it's, you know, certainly
17 something that some other utilities do do. But
18 historically we've calculated the abandon rate this
19 way.
20 THE CHAIRPERSON: Thank you.
21 MS. CARMAN: Now, with respect to the callback feature,
22 the Commission asked that we discuss the impact of the
23 feature on abandoned rates and in particular identify
24 other potential measures that may help us get some
25 additional value or information.
26 So in and of itself, the callback feature

is expected to reduce the abandon rate due to waiting time. So those customers that are hanging up because they felt that they've waited too long, this provides those customers an option. But since our customers typically don't experience a long wait time -- you may recall I said on average we're answering calls in less than a minute -- and with only a small percentage of customers using this call back feature, it's about 2 percent, the impact on the abandon rate overall isn't expected to be material.

So if you think about the numbers a little bit, if only 2 percent of the daily calls take advantage of this feature, and if we consider only a portion of those may have actually abandoned due to wait times, the impact would be minimal. So although again I can't say with certainly. I looked at 2016 and I looked at the months that the feature wasn't in place versus the months that the feature was, and on average it dropped by about 1.4 calls per day. So again, I can't say for certain that the reduction was due to the implementation of the feature, but it gives you a sense of the magnitude. And so then what that would work out to overall in terms of the total abandon rate, it would only impact the abandon rate by .3 percent.

So again, just demonstrating that because

of the minimal wait times that our customers experience, the relative size of customers using this feature, it's still, even though it's a valuable feature certainly to our customers, it's not going to have a big impact on the overall abandon rate.

It's also important to note, I think there were some questions in the IRs it was good to clarify that the way that we account for these callbacks, they are included in our existing telephone service factor metrics. So they're part of the denominator in terms of total calls. So due to the fact that the wait time may be a likely reason that a customer is choosing a callback, it's highly likely in those cases that those are actually going to be calls that were missing service level. So to that extent it's likely going to -- if we're in that situation where a customer wants a callback, it's likely going to be greater than an average pickup time of 48 seconds. So likely most of these callbacks I would actually expect to fall outside of the service level and thus get captured in our existing metrics, for those 30 percent of calls that we're not answering in 30 seconds or less.

So because of those reasons we really, you know, we thought there's limited value, right? The relative size of the abandoned calls overall. There'd be limited value gained by creating some additional

information or indicators or reports because it represents that overall small portion. And on balance, like James showed us, our customer satisfaction metrics are doing well. We're meeting our service levels. So at this time it's something we'll continue to keep our eye on, both the abandon rate and the callback feature, but you know, generally we've got an overall high level of customer service and service quality.

Yes.

Proceeding Time 11:58 a.m. T34

MS. RHODES: Janet Rhodes, CEC. With respect to the IVR, what types of solutions are there on there? Because I would think that a lot of the responses really are re-directional, like, who do you want to speak to? Whereas there's probably some that are solutions, such as our operating hours.

So I guess my question is, I'm trying to figure out how much of the IVR would actually solve anybody's problems enough to cause them to hang up satisfied, versus whether or not they were actually looking for redirection or something, and would not normally hang up except that they are wanting to try again, or something.

MS. CARMAN: Yeah.

MS. RHODES: Do you understand my question?

MS. CARMAN: Yeah, as well, I'll try, and then I might have some colleagues that will jump in, so -- when a customer connects through us, so, to the extent that we've got an outage, or we've got some sort of message that we want everybody to hear, that will play up front. And then they will select, you know, the reason that they're calling us. One of the things you may have read about in the application is, we do have some enhancements that we're putting in place. Those are expected to go in place shortly, that will provide some additional functionality for customers, so that they can get some of that information in terms of their account balance, due date, when's their next bill. That type of information will now be available to them once we do these enhancements they won't have to talk to an agent, so you know, we could definitely see a positive impact or positive feedback there.

And certainly your point about, you know, the message that customers get on the IVR -- we might have some information about an outage. So we've resolved their issue in terms of giving them the information they need. Are they happy about the outage? Maybe not, right? So when they are surveyed about the service they were provided, they may still respond in a way that suggests they're not happy, they're not satisfied. Yes, we dealt with the

1 response, we did it in a timely manner, but they're
2 still not overall happy. So it's tough to stay, you
3 know, without digging into, you know, the details of
4 the after-call surveys that we do.
5 And we also do surveys on customers that
6 use our online information as well, to understand some
7 of the areas where they can see changes.
8 MS. RHODES: Thank you.
9 MS. CRAIG: Marg Craig, Nelson Hydro again. Please
10 clarify. So when people call in, they hear an initial
11 message, whether that's regarding an outage or -- and
12 then they go into the call tree, and then they make a
13 selection?
14 MS. CARMAN: Yeah. So, you know, welcome to FortisBC, if
15 there's an outage going on, they'll hear an outage
16 message. Otherwise, it's, you know, what's the reason
17 for your call today? And then based off of how they
18 respond, they'll go into a certain queue.
19 MS. CRAIG: Perfect. So, I would expect higher abandon
20 rates earlier on. If I've heard that message, I know
21 that. But you're saying, if I recall correctly, that
22 the abandon rates aren't calculated until they go into
23 the call tree and are actually waiting for a
24 selection.
25 MS. CARMAN: No. So they're calculated right from the
26 start.

1 MS. CRAIG: Right from as soon as they call.
2 MS. CARMAN: Yeah.
3 MS. CRAIG: Okay.
4 MS. CARMAN: So as soon as that customer calls us and
5 connects that call.
6 MS. CRAIG: Yeah, okay. Perfect, thank you.
7 MS. CARMAN: Any other questions about the abandon rates
8 or the call-back feature or average speed of answer?
9 If you were hanging on the edge of your chair? Well,
10 then, I'll hand things over back to Diane, who I
11 believe will be opening up the question period.
12 MS. ROY: Okay. Just to check in whether we want to
13 carry on, or --
14 THE CHAIRPERSON: Yes. Unless there are a multitude of
15 questions, I think that they could probably be handled
16 within the next half-hour or so. So if everyone is
17 okay, we'll just carry on and hopefully -- if it goes
18 longer than that, then we will convene after lunch.
19 But let's continue on for the time being.
20 MS. ROY: Okay. Okay, so I think actually how I might do
21 it this time is kind of start at this end of the table
22 and work down by a different group. Because I know
23 Mr. Hobbs already had the first question that we're
24 waiting for him to ask, and it might be a little more
25 organized. I know at FEI we kind of went randomly,
26 but it might be simpler just to kind of move down the

table. So I'll turn it over to you.

Proceeding Time 12:03 p.m. T35

MR. HOBBS: Sure, thank you. Robert Hobbs, the ICG. System losses were a subject of ICG 4.1, and I don't think you need to turn there, but in response to that question you filed the 2012 system losses study. Is there a more recent study?

MR. KING: It's Jamie King. No, we haven't done any new loss study. The important thing under the PBR, any variants in actual losses do flow through to the customer under the flow-through deferral accounts. We're currently -- with the AMI meters, we are starting to work with that data to provide an updated loss study, but it's a project that's ongoing now and will be ongoing in 2018. But again, there's no impact to the customers because this is a flow-through item.

MR. HOBBS: Right, understood. Was that 2012 loss study, if not entirely, principally based on billing information and consumption data that you received? Was there any metering involved in the calculation of the losses?

MR. KING: Yes, definitely. I mean the calculation of loss is the difference between the metered generation and interties of our utility, all the power that comes in and is generated, and we compare that to the billed data. And the difference there is the losses.

1 MR. HOBBS: Right. So on an aggregate basis. But have
2 you identified areas on your system where the losses
3 might be higher than other areas?
4 MR. KING: Again as part of this AMI project, this is
5 something that we are looking into. We've got no
6 definitive studies on this but we are working to use
7 this AMI data to look at stuff like that including,
8 you know, theft reduction and issues on distribution
9 feeders that may not be related to theft reduction.
10 And that's an ongoing project.
11 MR. HOBBS: Right. But on your higher voltage portion of
12 your system, so it's not going to necessarily be
13 captured by AMI, if I understand your AMI system, have
14 you tried to identify, as I say, areas where the
15 losses might be higher using meters, using an
16 integrated meter system, system modelling of some
17 sort?
18 MR. KING: If we see an issue or think there may be an
19 issue it is something we would investigate. But in
20 general, no, we just kind of look at it in aggregate.
21 MR. HOBBS: When do you think you might produce your next
22 loss study?
23 MR. KING: Again this is something that we're currently
24 looking at the DATA with AMI. There's a lot of data
25 that goes into it so we will be continuing to look at
26 it in 2018. However, as we did discuss in that ICG IR

14.1, you know, the 8 percent that we were using, that is pretty consistent with what we've looked at over the past three years of 7.88 percent so we think we are fairly close in our system losses. But we will use that AMI data. We have to try and get a little more accurate, more timely accurate loss percentage.

MR. HOBBS: I don't think I've heard -- I appreciate your answer. I'm just unsure if I've heard an answer to the question as to when you might reduce the next loss. If you have a plan, when is it that you might produce your next losses study?

MR. KING: I'm not sure. It'll probably be 2018 or 2019. As you can see, we're using that 8 percent for the 2018 rates and I think that's probably appropriate for 2019 as well, as well as any variances that flow through and there's no impact to customers. But working with the same idea that if we do get a better methodology before that, it is something that we would implement.

MR. HOBBS: Okay. This is probably a question for James and it's my last question. Regarding outage hours, so generation outage hours, and I appreciate that it's provided in the PBR mechanism for information only, but there are a lot of idle hours largely due to the Canal Plan Agreement. And in the past we've asked for evidence about your comparison to other utilities in

the CEA studies, and the CEA data isn't available to interveners. I'm wondering if you have made that adjustment to your outage numbers and if you'd be willing to provide that to the Commission to have a look at.

MR. WONG: I'll ask one of my colleagues in Operations to look at it. Mike?

MR. LECLAIR: Mike Leclair from FortisBC. The CEA numbers that we state in the information only metrics are based on hydro units with similar duty cycles to that of our river plants. So it is sort of an apples to apples comparison of units that run in and around the same duty cycle.

MR. HOBBS: Is that something that you can make available?

MS. MARTIN: Joyce Martin. There is a comparison to the CEA statistics in Table 13-13 of the application.

Proceeding Time: 12:08 p.m. T36

MR. HOBBS: Okay. Thank you. I'll go look. And one, I said I only had one more question but I do have -- it's more of an undertaking, I think. Well, it is an undertaking. And it's your 2012 losses study. It looks like you're using different consumption numbers, but maybe not. Could you look at cells N4, N5, and N6, and compare them to B13, B14, and B15 in that study and either file an errata or explain why those

numbers are different? And as I say, I'm not expecting you to answer that now, we can do that on another date.

MR. KING: Tell you what, we'll look at it right here and if we can't answer it by the end of today we'll take it as an undertaking.

MR. HOBBS: Okay.

MS. ROY: So that's it for ICG?

MR. HOBBS: It is, thank you.

MS. ROY: So I'll move over to BCMEU and if there's any questions from the group there?

MR. LOVE: I think our representative here will ask for us.

MS. ROY: Okay.

MR. WEAFER: Sure, sure. Chris Weafer on behalf of the BCMEU and CEC. Three questions. One is following up on the discussions this morning, and I mentioned this to Joyce Martin in the break, we would like a best efforts rate forecast for the next two to three years on the information that you do have and whatever assumptions you want to put into it. It's important to the ratepayers to have some sort of predictable certainly. And last week with respect to gas we did some rate smoothing because of events that were expected, and so we'd like to know whether -- given we've got a low increase this year, is there anything

you're anticipating that would justify rate smoothing this year?

So the basic question is to have your best efforts rate forecast for the next three years?

MS. MARTIN: Two items, two things to comment on that. We did give some thought to whether we would be able to do that and we think that we can't really provide anything meaningful in terms of a three-year or a two-year rate increase going into the future. And the reasons are that there are just too many uncertainties at this point in time.

We do not have a load forecast in to the future, so these are, you know, the major components of a rate increase. We don’t have a load forecast. We don’t have any visibility of BC Hydro power purchase -- or BC Hydro price increases because the order in council that set the price increases, the last one that is available to us is the one April 1st, 2018, so we don’t know that. We know that there is the likelihood for some significant O&M increases, for example, as a result of the mandatory reliability standards, the O&M that Curtis talked about this morning.

And one of the really large or most significant issues is the impact of the flow-through accounts, which is quite different from year to year.

And just to give you an example, if I only think of the two components, the two biggest components in that flow-through account, which are the revenue and the cost of energy that are so impacted by load differences in year to year. Between the 2017 revenue requirements and the 2018 revenue requirements, the amount that that flow-through account affected by way of just those two line items was an $8 million difference. So in 2017 we saw a net recovery of around $4 million in 2018 rates. There's a net refund of about the same amount.

And so those swings can be quite large. And when I look at the total of all the things that we can't reasonably foresee at this point in time -- I mean, we could give you something and make a whole lot of assumptions, but I have to say I'm very reluctant to give you a rate increase or a rate forecast that I don’t have any confidence in. And that when I come back with next year's revenue requirements eight months from now it's highly likely to look nothing like what we would be able to say now. So for that reason I wouldn't have any confidence.

And to go to your second point of rate smoothing, I assume that you're considering if we were to see a significant rate increase for 2019 we might try to pull some of that forward into 2018, is that

what you're --?

MR. WEAFER: That -- so, yes. So, sorry, I don't mean to interrupt.

MS. MARTIN: Yeah. So I don't know how we would do that based on the fact that we don't know what the answer might be in 2019. So it doesn't seem a reasonable approach to me.

MR. WEAFER: Mr. Chairman, we're prepared to take the rate forecast on a best efforts basis with the variables identified and not hold them to it if those variables should occur but we're talking the last year of the PBR term, and ideally the next year after the PBR term, and that's relevant to repairs, and it's not an unreasonable request. It's been provided in the past by various utilities. So, we'd like to receive it even with the qualifiers.

Proceeding Time 12:13 p.m. T37

MS. ROY: And Chris, just one other thing that Joyce didn't mention, which, you know, I'm picking up on from what you're saying there. After 2019 we don't know what kind of regulatory rate-setting methodology we'll be under. We don't know the extent of rebasing. So it's going to be another complicating factor on top of that.

Now, when we were looking at -- on the gas side, there was a specific reason why we were

1 providing that information. And again, we just used
2 inflation and added in the two major projects that we
3 knew about. But it's because we had a credit balance
4 in a deferral account, and we were trying to
5 understand what the various amortization scenarios in
6 the future might be, so we have been, many times in
7 the past when we've had a rate decrease, we have not
8 flowed the rate decrease through, and we've held rates
9 flat, because it avoids that significant volatility in
10 rates.
11 And I take your point that if there was a
12 big rate increase the following year, you might want
13 to bring some of that forward. But we have never done
14 that. I have never seen the Commission approve a rate
15 increase in advance of when it's actually required, in
16 order to smooth rates.
17 Whereas, you know, when you have a decrease
18 you can amortize the balance. So those are some of
19 the reasons why I kind of add to what Joyce is saying.
20 We can always do something. We can just,
21 like, straight assume a 2 percent. I can tell you
22 right now, 2 percent is what we do, and then we'd
23 layer in maybe three of the capital projects that are
24 upcoming. But we can't make any assumptions beyond
25 that. So if that is what you would like, we can do
26 that, but I don't think that's particularly helpful.

1 MR. WEAFER: We'd like your best efforts of what you can
2 do for the next three years.
3 MR. BYSTROM: Chris Bystrom for FortisBC. I don't think
4 we can agree to "best efforts", Chris. I don't know
5 what you mean by best efforts.
6 MR. WEAFER: Reasonable efforts. Reasonable efforts,
7 Chris. I'm not trying to --
8 MR. BYSTROM: Well, we agree to do what Ms. Roy
9 described we would do: assume inflation, a few big
10 projects.
11 MR. WEAFER: Well, just to comment, I have to say that to
12 think that there's not a reasonable expectation as to
13 what the rate increase will be in the last year of PBR
14 is problematic to me, in terms of understanding
15 passing the ball to the management to run the utility
16 for the PBR term. So we certainly see for the one
17 year, it's as you talked about capital. Well, the
18 further out it is, the more difficult it is to
19 predict. We would certainly assume your assumptions
20 for 2019 would give us a reasonable comfort as to what
21 the rate increase may be, identifying the variables
22 that may be affected. As you go further out, accept
23 there may be more variables including coming out of
24 PBR.
25 But we would like reasonable efforts,
26 Chris, if that's better language, forecasts for the

1 next three years.
2 MR. BYSTROM: We would undertake to provide what Ms. Roy
3 described. But we've also described a lot of the
4 reasons why we can't do what you're asking. We don't
5 have a load forecast, Chris. So, that's just one
6 example. It is --
7 MS. MARTIN: We can give you a reasonable effort, but we
8 can't give you any reasonable comfort with it. So I
9 don't know what that will do for you.
10 MR. WEAFER: We'll be satisfied with a reasonable effort.
11 THE CHAIRPERSON: If I may just interject, you can
12 provide reasonable effort but it's not going to impact
13 what this panel will decide, because we're only
14 deciding on the 2018 rates.
15 MR. WEAFER: Understood, sir.
16 THE CHAIRPERSON: Okay. So as long as you understand
17 that
18 that's --
19 MR. WEAFER: Absolutely, yes.
20 THE CHAIRPERSON: There will be zero weight provided to
21 you, whatever projection or qualified number is
22 provided for 2019 or any year beyond that.
23 MR. WEAFER: That's understood. That's understood.
24 THE CHAIRPERSON: Okay.
25 MR. BYSTROM: It's Chris Bystrom again. If there is zero
26 weight, and I totally agree with your point, it's not

relevant to the proceeding. Then I would argue that we shouldn't be spending any time on producing an undertaking that will have zero weight.

MR. WEAFER: In terms of the proceeding, we're in a PBR term of five years. And while the determination on this year is on this year's rates, we are still in the process of trying to assess whether PBR is working or not as we come to the latter terms. And so while the document may not have weight for your determination on this year. We as ratepayers still are trying to understand that this is working properly or not, and typically we've been able to get from the utility a rate forecast. It's not an unreasonable request.

Proceeding Time 12:18 p.m. T38

MS. ROY: So just keep in mind, Chris, the O&M and capital are the only items subject to the PBR formula, and we can provide you with an estimate of that. If you're trying to assess the PBR term, that's definitely something we can do.

It's the other items that we don’t have control over that we can't forecast. So I'm comfortable providing you with something, but I was going to tell you right now I just don't want you to rely on it because I don't think it's appropriate for the group here to be using that in consideration when we know when you have a smaller utility like FortisBC

1 Electric, and that's one of the issues that we have,
2 things that aren't of a huge magnitude can have a big
3 impact on the rates, whereas in the gas side, a number
4 of things can happen. It won't have a huge movement
5 on a rate, so it's easier to forecast what's going to
6 happen there. We have much more volatility on the
7 electric side.
8 MR. WEAFER: But we've received this in the past.
9 MS. ROY: Pardon me?
10 MR. WEAFER: This has been provided in the past. You've
11 given rate forecast for three-year terms, this
12 utility, the smaller utility in the past. So --
13 THE CHAIRPERSON: So might I just suggest that Ms. Roy
14 has suggested that they might be able to provide
15 something but (a) it would not be long term and (b)
16 there would be all sorts of caveats on it.
17 MR. WEAFER: That's understood.
18 THE CHAIRPERSON: And so if you do it on that basis and
19 put the caveats in there so that everyone understands
20 that there is a lot of variables to take into account,
21 anything beyond one year. So can we do it on that
22 basis?
23 MS. ROY: Yes, we can do that.
24 THE CHAIRPERSON: Okay, so let's do it on that basis and
25 let's move on to the next question.
26 MR. WEAFER: Thank you. Thank you very much.

INFORMATION REQUEST

MS. ROY: Okay.

MR. WEAFER: I want to go to an IR, IR 123.2, and it relates to the financial statements, financial schedules.

MS. MARTIN: Sorry, is that your IR?

MR. WEAFER: Sorry, BCUC Staff IR 123.2. I'm recognizing it's not in the PBR but it's part of the evidence in this proceeding. And just again looking at the prudency of the utility. And this relates to the forecasted cost of the 2017 rate design application deferral account, and I'm having trouble understanding the estimate and then now the updated estimate.

But as I understand it, the original forecast of that proceeding was $700,000, and one of the -- there's been an update to it and one of the points is you've looked at your 2012 experience, which I assume you had when you made the first estimate, and now the estimate's gone up by $1.2 million. It's gone from 700,000 to $1.9 million and I'm just trying to understand what's occurred to cause that very material change in the estimate for that proceeding. It's about an $1.2 million increase since the original estimate. Can you help us with that?

MS. MARTIN: Joyce Martin. I think the short answer is that we were overly optimistic in making the first

estimate. We were not able to do the 2012 rate design application for that amount. FEI has not been able to undertake their rate design application for that amount. And so we just think it's more realistic that we recognize the complexity and the duration and the cost of ongoing regulatory proceedings. It's just, to us, a more reasonable expectation that we'll be closer to the update forecast than to the 700,000.

MR. WEAFER: So just at a high level can you -- in terms of what you originally forecast at 700,000, what were you anticipating for process versus what are you anticipating now that gets you to this amount? Are you anticipating a two-week hearing or -- this is a lot of money. And I guess one of the concerns, we talked about bundling in terms of capital. But we've just gone through a fairly lengthy detailed process with the same experts and the same legal counsel with Fortis Gas, and we're potentially recreating the wheel.

MS. MARTIN: Well, in terms of rate design, no, we are not, because an electric rate design can have no relationship to a gas rate design. So we are starting from zero on both. So, what we did here was to actually look at the costs that we incurred for the 2012 rate design and assume that we would incur something similar for the upcoming rate design.

Proceeding Time 12:22 p.m. T39

MR. WEAFER: Okay, thank you. Thank you. Actually, those are my questions. Thank you very much.

THE CHAIRPERSON: Thank you. Ms. Roy?

MS. ROY: Going over to BCSEA, then.

MR. ANDREWS: Yes. Bill Andrews, BCSEA and Sierra Club.

In response to the Commission's -- most of my questions are for clarification, really. The Commission's IR 12.4, to do with capital expenditures, there is a list -- a description, rather, of three types of capital expenditures exceeding the formula. And one of them is unanticipated transmission projects to address safety and reliability issues.

My question is whether capacity focused DSM is an alternative to the kind of spending described in that point under factors that are expected to contribute to capital expenditures (inaudible) in the formula.

MR. CHERNIKHOWSKY: So, it's Paul Chernikhowsky. The answer to that is no, it's not -- the unanticipated transmission projects are not related to the capacity of the system, but rather solely due to the condition of the assets themselves. So, regardless, for example, of a transmission line's capacity to serve power, it has to be in a physical state that it's able to operate safely and reliably. So the poles have to

be sufficiently strong, the insulators have to be in good condition as well. And that's what these projects are designed to address, is the condition of the asset.

MR. ANDREWS: Thank you. In terms of DSM spending in 2018, you've indicated that the actual spending will be the subject of a single-year DSM expenditure schedule to be filed in 2017, I gather. First of all, is that correct? 2017, we can expect it?

MS. MARTIN: Yes, that's right. We are hoping we will do that by January 1, 2018. And the reasoning for that is that because the expenditure schedules are required to basically follow the acceptance of a long-term demand-side management plan, and that long-term demand-side management plan, as you know, is currently in the argument phase before the Commission, along with our long-term resource plan. So we don't anticipate -- we are certain at this stage that we're not going to have a decision in that in time for us to build a multi-year DSM plan off of the long-term DSM plan, and therefore we have a need to file a one-year expenditure schedule to bridge that gap.

MR. ANDREWS: And then for the multi-year DSM expenditure schedule that you've indicated would be filed in 2018, do you have a more specific target timing within 2018 in terms of quarters?

MS. MARTIN: I am expecting that it will probably be about mid-year, depending on the timing of the acceptance of the long-term DSM plan, and then we would need a certain period of time to develop the demand-side management expenditure schedule.

MR. ANDREWS: Thank you. I have a general question about the outage management system and the usage of the Fortis AMI system. Is this something that BC Hydro has already, this type of outage management system? I'm not looking for great detail, but is this is a first for Fortis?

MR. ERNST: Dale Ernst, FortisBC. BC Hydro does have the AMI system, as I'm sure you're aware. Whether they have implemented a full outage management system I can't comment directly on. I do know they have a customer outage portal similar to the one that we have, so I would assume that they do, but I can't say for sure.

MR. ANDREWS: Thank you. There is a list in — I don't think you need to go to it — CEC 8.1, a list of projects that were reprioritized. And many of them include the term "scope". And just a clarification. Does that mean that the project was -- that it's being described is to determine the scope, as distinct from implementing what has been determined as being the scope?

Proceeding Time 12:27 p.m. T40

MR. CHERNIKHOWSKY: So, Paul Chernikhowsky again. No, Bill, when we're referring to "scope" there, we're referring to essentially the detailed scope of the project. So for example in prior years, what was identified would be a scope that says, "Conduct condition assessment and rehabilitation of transmission line X." But again, we don't know the details of how many poles will need to be rehabilitated, how much work we'll need to do in terms of insulator replacements, conductor replacements, you name it, until we actually conduct that condition assessment in the prior year. So it's the scope refinement that occurs as we go along through PBR that we're referring to there.

The high-level scope is certainly well known. We know which feeders and which transmission lines we're going to assess in future years, we just don't know the details.

MR. ANDREWS: Thank you. My last question relates to a comment in CEC 12.1 referring to the residential conservation rate impacts. And it said that the impact was anticipated to be -- to occur for five years. And my question is if you can refresh our memory, why the residential conservation rate impact was assumed to only be operative for five years?

MS. MARTIN: Just because of the difficulty of actually measuring the impacts of this kind of savings, conservation, or which is essentially a kind of price elasticity, we just had -- there had to be an assumption made about how long it would last, because you can't directly measure it, and it just seemed to be a reasonable assumption that it might take people a period of time in order to make the kind of capital investments that they might make, in order to, you know, bring their consumption back into -- or to actually affect their consumption after the introduction of that conservation rate.

MR. ANDREWS: All right. Well, thank you. Those are my questions, thank you.

MS. WORTH: I note the time, and you had originally indicated that we would check in at half-past twelve.

THE CHAIRPERSON: So, how many questions, Ms. Worth, do you have, and Mr. Quail? I am just wondering how much more time we would need?

MS. WORTH: Well, I have a question -- let's see, two questions and something that could be taken as an undertaking.

THE CHAIRPERSON: And Mr. Quail?

MR. QUAIL: I have a couple of points, it might be five, seven minutes, something like that.

THE CHAIRPERSON: Okay. If everyone is agreeable, let's

1 stretch it a little bit more, but let's see if we can
2 be succinct.
3 MS. WORTH: Okay.
4 MR. WEISBERG: I wasn't --
5 THE CHAIRPERSON: Oh, I'm sorry. I'm truly sorry, Mr.
6 Weisberg, I forgot you.
7 MR. WEISBERG: I was in the corner. Just a single
8 question, Mr. Chair.
9 THE CHAIRPERSON: Okay, so let's do that, please.
10 Because I know we all have things that we need to get
11 done.
12 MS. WORTH: Okay. So I note that FBC has changed its
13 methodology to determine its UPCs. Basically in the
14 past it was a three-year average. Basically using the
15 historic values to estimate UPC, and they were actual
16 weather normalized values that included the impact of
17 DSM, according to BCMEU IR 4.1 and Exhibit B-2,
18 attachment 2, page 7.
19 But for 2018, FBC has done a trend
20 analysis, so as a result, the FBC -- sorry, the UPC
21 for 2018 was reduced from 11.4 megawatt hours to 11.04
22 megawatt hours. And there was an impact of 1 percent
23 in reducing the residential load.
24 So, I was wondering if Fortis would comment
25 on the appearance that the DSM is actually counted
26 twice in that. Because --

Proceeding Time: 12:32 p.m. T41

MS. MARTIN: Sorry, I'm not certain why you're saying DSM has been counted twice?

MS. WORTH: Well, Fortis basically proceeds in its calculation, its new calculation, to adjust the residential forecast based on the UPC and customer count for DSM savings. So that appears to actually count the savings twice.

MS. MARTIN: Ah, okay. That's actually not new. I'll just make a comment on the fact that we haven't changed our method, even though this is the first year that we did see a decline in the UPC. Every year we do do that trend analysis and if there is nothing statistically significant, then we don't impose a downward trend on it. So this is the first year that we have actually seen a downward trend that is statistically supported.

MS. WORTH: Okay.

MS. MARTIN: Now, in every year that we have actual loads, that incorporates the impact of any demand side management that's impacting customers' usage. So that's not something different between past forecasts and the current forecasts, it's just that this is the first time that the statistics have supported the fact that customers are in fact using less on a per customer basis.

MS. WORTH: Okay. And then this is where I would sort of ask for the undertaking. I'm wondering if you can provide a version of Exhibit B-2, Attachment 2, Schedule 5.3 broken down by customer class?

MS. MARTIN: Sorry, could be have that reference again, please?

MS. WORTH: Sure. It is Exhibit B-2, Attachment 2, Schedule 5.3.

MS. ROY: Exhibit B-2 is the application itself, is that the one you're referring to?

MS. WORTH: Yes.

MS. ROY: And attachment --?

MS. WORTH: Attachment 2.

MS. ROY: Appendix? Are you talking about an appendix?

MS. WORTH: Oh, sorry, yes, Appendix 2. Schedule 5.3.

MS. ROY: Appendix --

MS. MARTIN: A-2, you mean A-2?

MS. WORTH: Sorry, I have it in my notes. I don’t have the application, but I need to be able to sort of double check, but --

MS. MARTIN: Sorry, Table 5.3 I'm looking at, that is a DSM and other savings before losses? What is the subject of the --

MS. WORTH: Yes. Can I have that broken down by customer class?

MS. MARTIN: Sorry, you're looking for that for each year

beginning in 2012?

MS. WORTH: Yes.

MS. MARTIN: Okay. Yes, thank you.

INFORMATION REQUEST

MS. WORTH: Great, thank you.

This is sort of a dual question, but I'll be as quick as possible. FBC has calculated losses based on history and then makes additional adjustments for incremental AMI savings set out in table 3-4. And I was wondering whether Fortis can explain the forecast loss factors as a percentage of before savings gross load? And that may be something for Jamie King.

MR. KING: Sorry, can you repeat the question?

MS. WORTH: Sure. I was just wondering of you could explain the forecast loss factors as a percentage of before savings gross load?

MR. KING: Do you have a reference?

MS. WORTH: Let's see. There is -- if you look at the Table 3-4, "System Losses before and after AMI 2013-2019". And that was from Exhibit B-2, page 32. So there's 7.95 for 2017, 7.90 for 2018. So I wondering if you could explain how those forecast loss factors as a percentage of the before savings gross load were calculated.

Proceeding Time 12:36 p.m. T42

MR. KING: I think your question is how these percentages were calculated?

MS. WORTH: How the forecast loss factors as a percentage of the before savings gross load were calculated.

MR. KING: If we're going to get into those numbers in detail, we may have to take that one away.

MS. WORTH: That's fine, I'm happy to do that.

MS. MARTIN: Sorry. Maybe I can just ask for a bit more clarification in the actuals, which is to the end of 2017. Jamie described earlier today how we calculate the actual loss values. I think it's a bit of a misnomer to refer to those as "before savings" because we are not actually able to break out the savings from the embedded historical data. So to the end of 2016, just are just actuals on observed gross load.

For 2017 and 2018 we start with an assumption that losses are 8 percent of gross load, and then there are loss adjustments as a result of the savings, such as the demand-side management and the reservation conservation rate, and so forth. And those calculations were shown in the response to CEC IR 1.11.3.

MS. WORTH: 1.11.3?

MS. MARTIN: Yes. Now, those give a gigawatt hour value for the losses, but they describe how those other savings you have the loss values. So they would go

1 into the calculation of losses.
2 MS. WORTH: Okay. So you're saying basically that the
3 2017/2018, which is the seed and forecast year, are
4 being calculated in the exact same manner as the
5 actuals from 2012 to 2016. Is that correct?
6 MS. MARTIN: No. The actuals from 2012 to 2016 are
7 observed values.
8 MS. WORTH: Yes.
9 MS. MARTIN: And 2017 and 2018 are calculated based on
10 the assumptions.
11 MS. WORTH: On the assumptions, okay. And those
12 assumptions are, as you said, talked about in CEC
13 1.11.3, is that correct?
14 MS. MARTIN: They describe how the -- they show the
15 gigawatt hour value of the losses.
16 MS. WORTH: Okay.
17 MS. MARTIN: That are based on the various components,
18 and that is what changes the assumption from 8.0
19 percent of gross load.
20 MS. WORTH: Okay. And this is perhaps something again
21 for Jamie King. But it would appear that there's no
22 allowance for the possibility of AMI leading to
23 existing grow operations going out of business.
24 Obviously some are going to not choose to become
25 paying customers. So, is that included on the AMI
26 impact on losses?

MR. LEYLAND: Sorry, can you restate the question?

MS. WORTH: Sure, okay. So, you know, you have grow operations, and the introduction of AMI. Now it appears that there's no actual allowance in this -- in the application for the possibility of AMI leading to those operations going out of business. So I wanted to know whether that actually was the case, and if not, where it is factored in.

MR. LEYLAND: So I think that would depend -- again, Mike Leyland, FortisBC. I think that would depend on whether or not they were paying grow loads or stealing, right? So what is reflected in the application is the expected change in the number of tap sites, not necessarily the overall change in the number of paying sites. That would be, I'm assuming, reflected in the overall load forecast.

MS. WORTH: Typically when we're talking about the impact of AMI on grow operations, it's because it's more difficult to actually steal the power.

MR. LEYLAND: Correct.

MS. WORTH: So what I was asking was, the impact on the loss. So it would be from non-paying grow operations going out of business, rather than converting to paying customers.

MR. LEYLAND: Non-paying grow operations going out of business.

MS. WORTH: Yes.

MR. LEYLAND: I'm not sure that's a reasonable expectation. I think if they're in business and they have a diversion that we haven't detected, I'm not sure what their incentive would be to fold up shop, you know.

MS. WORTH: Okay.

MR. LEYLAND: So to speak.

THE CHAIRPERSON: Ms. Worth, are you getting to the end of it? Because I mean, we've still got two other people.

MS. WORTH: Yeah, this is my last question. This is my last question.

THE CHAIRPERSON: I hope. Thank you.

MS. WORTH: It just -- it appears that there is no allowance for the change in losses on the -- that's attributed to the AMI. Is that the case? Because that's certainly something that -- because, you know, one of the major things that was used as a justification for AMI in a number of venues and different utilities is, the impact on non-paying customers like the grow operations. I was wondering if that was the case, there is no allowance for this in your forecasting of the losses?

Proceeding Time: 12:42 p.m. T43

MR. LEYLAND: I think what's reflected in the forecast,

as I've stated, is the forecast change in the number of theft sites. So, whether that's a result of us identifying them, or them electing to leave the service territory, that is what we would see in the forecast.

MS. WORTH: Okay.

MR. LEYLAND: Yeah, and to the extent that we have identified somebody who is stealing, and dealt with that, and they have not become a paying customer, then yes, your gross load is going to be reduced.

MS. WORTH: Okay, that answers my question. Thank you, and those are all my questions. Thank you.

MR. QUAIL: Shut down all the grow ops and you're going to crash the regional economy and your load is going to flatline, and then we're back --.

Speaking of loads, with respect to the request from Mr. Weafer about rate forecasts, and the question of load forecasts. Is there some reason why you wouldn’t apply the load forecasts that are in your current long-term electric resource plan proceedings?

You're saying you don’t have load forecasts? And maybe I misunderstood something, but filing your final argument a month from today actually, you've got your long-term electric resource plan which has load forecasts, so I would suggest you apply those to give some greater accuracy to the

1 information that Mr. Weafer has asked for, unless I am
2 missing something.
3 MS. ROY: I'll wait for Joyce --
4 MR. QUAIL: Just a helpful suggestion more than a
5 question, but I don't understand the point that you
6 don't have a load forecast.
7 MS. ROY: I'll wait for Joyce to comment. I do know
8 there is a different method that goes into calculating
9 the long-term electric resource plan load forecast, as
10 compared to the annual one, because it's looking for
11 longer term trends, and in doing the annual, we're
12 just using the prior years to forecast what is going
13 to happen one year out. I'm not saying, Jim, that it
14 wouldn't be a reasonable way to go about -- we could
15 incorporate whatever that longer term trend is in our
16 forecast. We could do that, and I don't know again,
17 if it is going to be any more accurate than just
18 holding the forecast flat though.
19 MR. QUAIL: Well, for example there is your information
20 request to the CEC at page 36 in that proceeding.
21 There is a residential load forecast using B.C.'s tax
22 average population forecast with year-to-year after
23 savings per, you know, number of gigawatt hours. I
24 just suggest you plug those in and it might help you
25 find the numbers.
26 MS. ROY: Yeah, and the problem we have with that is

already we are probably out of sync with that forecast, because this year, as Joyce discussed, we've had a significant load decrease. So, if you then were going to plug in the following year, I bet you you are going to see a huge increase in load to get back to that number. But as far as the percentage change that is assumed in the long-run, we could maybe apply that to the forecast. So. But thank you for your suggestion.

MR. QUAIL: Okay, I hope that is a helpful suggestion.

I wanted to ask a couple of questions about the Waneta Dam, and these are referenced in a couple of IRs from MoveUP, 8.1 and 8.2. You don’t need to turn to those right now. But very briefly, for people who may not be familiar with the issue, and correct me if I've got any of the basic details wrong, this was a dam that has been one-third owned by Teck, and two thirds by Hydro, and Teck put its two-thirds interest on the market and Fortis made a bid, 1.2 billion. It was effectively pre-empted by Hydro. And that they had a deadline, and they opted to pre-empt it and so subject to Commission approval, would squeeze Fortis out of the picture in occupying that ownership stake in the dam. And as a couple of background items, my understanding is Waneta is subject to the Canal Plant agreement, so its actual operation is in fact

1 determined to a large extent by the optimization of
2 hydraulics through that region. And secondly the
3 energy from the dam is earmarked for the Teck Smelter
4 for 20 years. My understanding. So, but I assume
5 that it was perceived as having a long-term system
6 benefit for FBC, or it would not have put in a bid to
7 purchase that stake, for $1.2 billion.
8 **Proceeding Time 12:46 p.m. T44**
9 MS. MARTIN: Could I just interrupt you there? We did
10 respond in your first IR, which was 8.1, that the
11 regulated electric utility is not the entity that had
12 sought to purchase the Waneta Dam. It was our --
13 MR. QUAIL: Would not be the nominal owner of it. But
14 presumably there would be --
15 MS. MARTIN: But we still would have been -- it wouldn't
16 have affected this utility in terms of that power
17 availability. Any power that we wanted to -- that we
18 were able to access from it would have had to be
19 subject to energy supply agreements and to be approved
20 by the Commission as well.
21 MR. QUAIL: Yes, I understand that. So the stake is
22 actually held by a non-utility entity of Fortis, but
23 presumably -- I was hoping not to make this too long -
24 - the purpose of it, the output from it isn't for the
25 gas utility, let's put it that way. So there would be
26 arrangements between the electric utility and the non-

1 utility entity, in terms of use of it.
2 My question is -- much more pragmatically -
3 - whether that apparently slipping out of grasp of the
4 Fortis family, shall we say, gives rise to a need to
5 obtain equivalent resources, given its unavailability
6 at least at the call of Fortis. Is this leaving a
7 hole in your plans for your resource stack?
8 MR. KING: So, Jamie King, FortisBC. No, there is --
9 none of the resources from Waneta were ever -- are
10 ever -- are currently, sorry, contacted to the
11 utility. We used to do some more deals with them
12 before, but they sold that one-third to BC Hydro, so
13 all of that power is currently, a third of it, roughly
14 a third goes to Hydro, and the rest goes to Teck. And
15 that would have continued had Fortis Inc. purchased
16 it.
17 MR. QUAIL: Right.
18 MR. KING: And it's going to continue with BC Hydro
19 purchasing it. So it's no change to our resource.
20 MR. QUAIL: Okay, thanks very much. That's all I wanted
21 to know.
22 THE CHAIRPERSON: Okay. Mr. Weisberg? Thanks for your
23 patience.
24 MR. WEISBERG: Thank you. I just wanted to -- Fred
25 Weisberg, Irrigation Ratepayers Group. Just wanted to
26 follow up on a question from Mr. Hobbs earlier about

systems loss study. And in the response that you gave, there was a reference to finding better methodology. It was a little vague about the sort of timing and the effort. Is that a specific thing that Fortis will pursue in 2018? And therefore, does it have any cost consequences in 2018?

Proceeding Time 12:48 p.m. T45

MR. KING: I think we will be looking at it, and (inaudible) bucket of O&M, we're not asking for any additional funds.

MR. WEISBERG: Okay. And is it really that search for an improved methodology that you're saying is the main impediment to bringing out a new system loss study?

MR. KING: Well, it's leveraging the new data, and it's finding out how we can basically compile it all and use it in a way that's accurate. So it is a bigger process that we probably would have thought, when you just think we have all this AMI data, and we could --

MR. WEISBERG: Yeah.

MR. KING: So, you know, it -- the current loss study that we did in 2011 and 2012, it is fairly accurate. It's just it takes three months to get accurate data for a current month. So, you know, with the AMI data we expect to have a very similar study, but it's going to be more timely.

MR. WEISBERG: Okay.

MR. KING: And we would know kind of month to month how are losses are doing, rather than having to wait two or three months.

MR. WEISBERG: But that is something that you'll actively pursue in the 2018 year?

MR. KING: Yes. Yes.

MR. WEISBERG: Okay.

MR. KING: But as I mentioned earlier, any variance in actual losses from what we've got forecast in the plan is a flow-through 100 percent to the customer. So there is no real risk to the customers, using what we're using right now. But you know, like I say, there is probably a better method that we will be investigating.

MR. WEISBERG: Thank you. Thanks.

THE CHAIRPERSON: Ms. Roy, you have the final word.

MS. ROY: So, any questions from staff, just before --

THE CHAIRPERSON: Oh, wait a minute, I'm sorry. Yeah, I apologize. I forgot.

MS. BURETTA: I have one quick question for Paul, I think. It's (inaudible) expenditures. So in response to BCUC IR 12.4, FBC identifies other factors that are expected to contribute to capital spending exceeding the dead band in 2018 and 2019. Can you please explain why each of the three factors you've listed are not factored into the base capital?

1 MR. CHERNIKHOWSKY: I'm sorry, I'm going to have to ask
2 you to restate that. I just had a hard time hearing
3 it. One more time?
4 MS. BURETTA: So, BCUC IR 12.4.
5 MR. CHERNIKHOWSKY: Yes.
6 MS. BURETTA: FBC identified three other factors that are
7 expected to contribute to the capital spending
8 exceeding the dead band. Can you explain why each of
9 the three factors you listed are not factored into the
10 base capital?
11 MR. CHERNIKHOWSKY: I'm not entirely sure what you're
12 referring to by "base capital". Are you referring to
13 --
14 MS. BURETTA: The formula.
15 MR. CHERNIKHOWSKY: -- were not included in the 2013 base
16 that was set?
17 MS. BURETTA: Yes.
18 MR. CHERNIKHOWSKY: Again, the PBR mechanism was, we used
19 a forecast of 2013 expenditures to establish a base
20 for PBR. The actual work that would get done over the
21 term of PBR was not based on budgeted expenditures for
22 each year. That's not what was used to determine what
23 expenditures would be. So we have listed some factors
24 here that were unanticipated, yes, in 2013 as examples
25 of pressures that we've had to absorb that were not
26 historically expenditures that we would have incurred.

1 So I don't know if that answers the question.
2 MS. BURETTA: So factors such as the additional
3 substation project to address end-of-life equipment
4 replacement wouldn't have been foreseen in 2013?
5 MR. CHERNIKHOWSKY: That was with respect to learnings
6 now that we've seen from other utilities and industry,
7 where equipment failure rates are different from what
8 we anticipated back in 2013.
9 So, again, better information that we have
10 now that we didn't have back in 2011 when those
11 forecasts were developed.
12 MS. BURETTA: Okay, thanks.
13 THE CHAIRPERSON: Now, did I forget anyone else?
14 MR. KING: I would like to (inaudible) Mr. Hobb's earlier
15 question, and you can -- your reference was to
16 attachment 4.1 to ICG IR 4.1. The issue appears to be
17 the data in N-4, 5, and 6 and O-4, 5, and 6 don't
18 match the January and February data for 2012.
19 And as far as I can tell, it appears to me
20 this could be a slight error just in the data.
21 They're off about 2 gigawatt hours each. However, I
22 can't speak to which one's correct. If you like, we
23 can take that away and find out which of that billing
24 data is correct.
25 **Proceeding Time: 12:48 p.m. T46**
26 However, the materiality of it is very

small, and I think if using either/or data would only change the loss factors by two or three basis points, so 0.02 or 0.03 percent. And any changes to this at this stage would make this no longer the 2012 loss study, it would be a revised study. So whatever you'd like us to do, but I do acknowledge that there is a slight error there.

MR. HOBBS: Yeah, I don't think you need to do the work, but I would like an opportunity to call you if that turns out to be necessary, but we don't need to do it on the record.

MR. KING: Okay, yeah. I'll give you a card after.

MR. HOBBS: Thank you.

THE CHAIRPERSON: Ms. Roy, it is now your turn.

MS. ROY: Okay. That's great. I had four undertakings, now I'm down to three.

The first one I have is from slide 13 of the presentation a request to calculate the 2018 and 2019 rate impacts under the two scenarios that were shown there, and that's from the Commission staff.

I have an undertaking for Mr. Weafer regarding rate forecasts for three years and undertaking reasonable efforts to provide those, so we've agreed to do that.

The other one I have is from BCOAPO, Exhibit B-2, Appendix A-2, Table 5-3, would like that

for each year, 2012-2018 broken down by customer class.

And did I miss anything else that we were expected to follow up on?

MS. ROSS: I believe it was another undertaking, just my question to Paul earlier regarding a response to BCUC IR 11.1.1. And he suggested that he could provide a list of the projects that were contributing to the expenditures for the most significant categories there.

MS. ROY: Okay. I don't recall that one, so Paul, if you agree, then we took that undertaking.

Yes, thank you.

THE CHAIRPERSON: Okay. And if there's nothing else, thank you all for your patience and thank you for staying a little bit longer. And we are now adjourned.

(PROCEEDINGS ADJOURNED AT 12:55 P.M.)

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

D.A. Bemister, Transcriber