BRITISH COLUMBIA UTILITIES COMMISSION

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

And

FortisBC Energy Inc. (FEI)
2016 Rate Design Application

Vancouver, B.C.
September 12th, 2017

Streamlined Review Process

BEFORE:

K. Keilty,	**Panel Chair**
W. Everett,	**Commissioner**
D. Enns,	**Commissioner**

VOLUME 5

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APPEARANCES

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L. WORTH K. FEENEY	Counsel for British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, and The Tenant Resource and Advisory Centre (BCOAPO)
D. BURSEY	Counsel for Teck Resources Limited, Domtar Inc., Weyerhaaeuser Company Limited and Zellstoff Celgar Limited Partnership (Industrial Customer Group/ICG)
W.J. ANDREWS	Counsel for B.C. Sustainable Energy Association and Sierra Club of B.C. (BCSEA/SCBC)
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INDEX OF EXHIBITS

1 **CAARS**
2 VANCOUVER, B.C.
3 September 12, 2017
4 **(PROCEEDINGS RESUMED AT 8:58 A.M.)**
5 THE CHAIRPERSON: Good morning, and welcome. My name is
6 Karen Keilty, panel Chair for Fortis Energy Inc.'s
7 2016 rate design application. With me today are other
8 panel members on this application: Doug Enns and Bill
9 Everett.
10 Order G-109-17, issued on July 28, 2017,
11 established regulatory process for this application,
12 which includes today's streamlined review process, or
13 SRP in respect of the following key topics: the cost
14 of service allocation, or COSA, studies included in
15 the application and whether the revenue-to-cost, RC,
16 ratio and the margin-to-cost, MC, ratio, or a
17 combination of both, should be used to guide rate
18 design and the corresponding ranges of reasonableness
19 of the selected ratios.
20 As outlined in the reasons for decision
21 accompanying G-109-17, all other topics raised in
22 FEI's 2016 RDA are outside the scope of this SRP and
23 will be addressed at another time. The panel
24 determined that these topics were both discrete issues
25 which are separate from the rate design issues and
26 other parts of the application and could be covered

more effectively through an SRP, while still providing procedural fairness, public participation, and transparency.

The panel also notes that a decision on these key topics will impact FEI's rate design proposals and would allow FEI to make adjustments to its rate design proposals if necessary.

This SRP is intended to review in a relatively informal manner specific topics in the application that lend themselves to an expedited review, while still providing procedural fairness, public participation, and transparency. While the process isn't as formal as an oral hearing, it will be transcribed.

In the interests of efficiency, the regulatory timetable allowed for technical questions in relation to the key topics which are the subject of this SRP to be filed in advance. FEI filed its responses to those technical questions on August 31st, 2017.

Proceeding Time 9:01 a.m. T02

The panel would also highlight that the technical questions were intended to reduce or eliminate the need for undertakings and a possible extension of the regulatory timetable.

As explained in Exhibit A-4, Commission

1 staff retained an independent consultant, Elenchus
2 Research Associates Inc., to produce two independent
3 reports; the first, a cost of service allocation
4 report, and the second, a rate design report, both of
5 which form part of the evidentiary record for this
6 proceeding. Elenchus has filed both reports and has
7 also filed responses to Information Requests from
8 proceeding participants on both reports. Consultants
9 from Elenchus are here today and will participate in
10 the SRP in the manner I will describe in a moment.
11 The SRP will proceed as follows. Following
12 my opening statement, we will have a safety briefing
13 from our Hearing Officer, Hal Bemister. Once that is
14 complete, we will begin with introductions of the
15 parties, followed by a presentation from FEI and then
16 a presentation from Elenchus. During their
17 presentation, parties will be allowed to ask
18 clarifying questions. I will leave it up to FEI and
19 Elenchus to determine if and when a short break is
20 necessary.
21 After the presentations are complete,
22 depending on the timing, we will take a break, which
23 will be followed by a question and answer session.
24 The order of the questions and answer sessions will be
25 as follows: Interveners may ask FEI or Elenchus
26 questions. Second, Commission staff will then ask

either FEI or Elenchus questions. Third, FEI may then ask Elenchus questions, and fourth, the panel may ask FEI or Elenchus questions.

This SRP will conclude after the question and answer period, as this SRP will not include arguments. The timetable for written arguments on these topics was established in G-109-17.

We will now have the safety briefing, and then proceed to the introductions, beginning with representatives of FEI. As you introduce yourself, please state your name and spell it for the record, and identify the parties that you represent.

Please go ahead, Hal.

THE HEARING OFFICER: The emergency exits are by both the men's washroom and the women's washroom, which are in the centre of the building. If the fire alarm does go off, we must leave the floor. We have no choice.

And complaint department today is Roberta, who is not in the room. So that's no problem. So -- anyways, we'll start.

MR. GOSSELIN: My name is Richard Gosselin. I'm spelled R-I-C-H-A-R-D, G-O-S-S-E-L-I-N. Manager, cost of service, for FEI.

MS. TABONE: Gail Tabone, G-A-I-L, T-A-B-O-N-E. I'm with EES Consulting. And I am the cost of service and rate consultant to FEI in this proceeding.

1 MR. PERTTULA: My name is David Perttula. My last name
2 is spelled P-E-R-T-T-U-L-A. And I am senior manager
3 of rate design and projects for FEI.
4 MR. BYSTROM: My name is Chris Bystrom, last name is
5 spelt B-Y-S-T-R-O-M. Counsel for FortisBC Energy Inc.
6 MS. ROY: Diane Roy, last name R-O-Y. And I'm the vice-
7 president of regulatory affairs for FortisBC.
8 MR. TOKY: Atul Toky. My last name is spelled as T-O-K-
9 Y. I am manager, rate design at FEI.
10 MR. MOORE: My name is Ed Moore. Last name is spelled
11 M-O-O-R-E. I'm cost of service manager for FortisBC
12 Energy Inc.
13 MS. BEVACQUA: Ilva Bevaqua, manager of regulatory
14 compliance and administration for FortisBC. Last name
15 is spelled B-E-V-A-C-Q-U-A, first name I-L-V-A.
16 MR. MARTISKAINEN: Jouni Martiskainen with Catalyst
17 Paper. J-O-U-N-I, M-A-R-T-I-S-K-A-I-N-E-N.
18 MR. HODGINS: Kevin Hodgins with FEI, industrial
19 accounts. Last name H-O-D-G-I-N-S.
20 MR. BURSEY: Good morning. My name is David Bursey, last
21 name is spelled B-U-R-S-E-Y. I'm with the Industrial
22 Customer Group, which is Teck, Domtar, Weyerhaeuser,
23 and Celgar.
24 MS. JUBB: Hello. My name is Anthea Jubb. I am with BC
25 Hydro, manager, Terrace. And my last name is spelled
26 J-U-B-B.

1 MS. RYAN: Dani Ryan with BC Hydro. I'm in cost of
2 service.
3 MR. WEAFER: Chris Weafer, from the law firm Owen, Bird.
4 Counsel to the Commercial Energy Consumers Association
5 of British Columbia.
6 MS. RHODES: Janet Rhodes with Commercial Energy
7 Association of B.C.
8 MR. ANDREWS: Bill Andrews. I'm counsel for the B.C.
9 Sustainable Energy Association and Sierra Club of B.C.
10 And I understand that Tom Hackney is participating on
11 line.
12 MS. FEENEY: Kate Feeney, F-E-E-N-E-Y. Counsel for
13 BCOAPO.
14 MS. WORTH: Leigha Worth, here as counsel for BCOAPO as
15 well.
16 MS. TRAN: Hi. Julie Tran, T-R-A-N. I'm a consultant
17 for the Commission.
18 MS. TRESOGLAVIC: Marija Tresoglavic, M-A-R-I-J-A, T-R-E-
19 S-O-G-L-A-V-I-C. Staff with the Commission.
20 MR. MILLER: Paul Miller, M-I-L-L-E-R. Counsel for the
21 Commission.
22 MR. CHONG: Doug Chong, C-H-O-N-G. Commission staff.
23 MR. SOUTH: Errol South, E-R-R-O-L, South. Commission
24 staff.
25 MR. TODD: John Todd, last name T-O-D-D. President of
26 Elenchus.

1 MR. ROGER: Michael Roger. Last name, R-O-G-E-R. I'm an
2 associate consultant with Elenchus.
3 THE CHAIRPERSON: Okay. FEI.
4 **Proceeding Time 9:08 a.m. T3**
5 MR. PERTTULA: Thank you, Commission panel, and thank you
6 all for coming today. This is a streamlined review
7 process about our cost of service allocation study,
8 and the other main topic is the range of
9 reasonableness. So I'll just be doing the first
10 couple of slides, and then Rick Gosselin will be
11 taking over for the lion's share of the presentation.
12 This is just a brief agenda of what we plan
13 to cover. So, an overview of the cost allocation
14 study. The results, the COSA results, some comments
15 on EES' review of our COSA study, brief comments about
16 Elenchus' review of our COSA study, the report, and we
17 understand that Elenchus is making a presentation, so
18 the comments will be brief in that regard. Also a
19 discussion of key areas of interest, and finally a
20 conclusion.
21 This is a single slide to sort of put the
22 application in context, and so the three major areas
23 of rate setting for utilities are, one, first of all
24 to establish the revenue requirement, and that is the
25 pie on the left-hand side of the screen. Then, once
26 that is established, the next is the cost allocation

1 process, and that is the pie with the blue dotted
2 circle around it. And finally there is rate design
3 which is determining how the rates are established to
4 recover the costs of each rate class.
5 So, just briefly on the revenue requirement
6 just to set that context, the coloured wedges are what
7 constitutes the parts of our revenue requirement, and
8 this is the delivery revenue requirement related to
9 FortisBC's pipes and other equipment involved in
10 delivering service. So, the main components are the
11 earned return, which is sometimes called the return on
12 rate base, and that consists of debt, interest, and
13 return on equity in the proportions that debt and
14 equity fund the rate base.
15 I'll go with the blue wedge at the bottom
16 there. That is the operating and maintenance expenses
17 that the utility uses. This is our resources, our
18 labour, and other resources that are involved in
19 operating the utility in a safe and effective
20 manner.
21 **Proceeding Time 9:11 a.m. T4**
22 There is a red wedge in there related to
23 property taxes, and we pay property taxes to the
24 municipalities that we operate in, and so that is a
25 part of our cost of services as well. And then the
26 yellow is depreciation and amortization, and that, you

can characterize that as the return of capital. It is the way that through depreciation we recover that the principal that has been invested in capital. And then the final purple wedge there is related to income taxes. And so all of these components comprise what makes up our revenue requirement.

And finally, the two grey wedges, they are related to the natural gas and upstream costs. So, the grey wedge, the bigger grey wedge is for commodity costs. These are natural gas that we acquire from third parties, and then the smaller grey wedges for what are called the mid-stream costs, sometimes called storage and transportation costs. So, the main part of our discussion here today is obviously about the cost allocation, and so what the other pie is trying to demonstrate is that cost allocation ends up allocating each of these components to the different rate classes, and that is what we will be going into detail on.

The final one, rate design is for follow-up process in this proceeding. So, it is not on the agenda for today. What is not mentioned here, another major topic is the range of reasonableness, so we'll be getting into that as well. So, that just sets the big picture background, and I'll invite Rick to take the presentation from here.

1 MR. GOSSELIN: Thank you, Dave. Thanks everyone for
2 coming today. I have a bit of a cold, so I might
3 sound a little horse, but I will do my best to be
4 clear and take as many questions as you need to ask to
5 clarify the content.
6 So, following on from Dave's context about
7 the SRP, I'm going to spend five minutes or so, maybe
8 10 minutes to talk about the COSA, and the purpose of
9 the COSA -- rather the overview of the COSA and how it
10 is used in the process.
11 The purpose of the COSA is ultimately to
12 fairly split up the revenue requirement, or the cost
13 of service for delivery, among FEI's customer groups,
14 or rather FEI's rate schedules. And nearly all the
15 costs of the utility are shared. So, if you've got to
16 think about it, we've got all this pipe facilities,
17 all these things in the ground, all the buildings, you
18 know, vehicles. Ultimately it is predominantly all
19 shared cost. The only costs that really are
20 attributable to just one customer is the meter and the
21 service line that attach them to the distribution
22 system. So, the COSA is an important part of the
23 process to split up all these shared costs.
24 **Proceeding Time 9:15 a.m. T5**
25 The methods we have used are, they follow
26 standard utility practice as both the EES report and

1 the Elenchus report have identified with some, you
2 know, some other opinions in there as well. And they
3 include judgments, estimates, and approximations.
4 In accordance with standard utility
5 practice, the COSA follows three steps. The
6 functionalization of costs, these are -- sorry, the
7 functionalization, then the classification of those
8 costs into what caused it, and then finally the
9 allocation of those costs to the various rate
10 schedules.
11 The functions FEI has used, you can see on
12 the screen there. Distribution, transmission,
13 storage, customer accounting, marketing, and gas
14 supply. Now, when we talk about customer accounting I
15 want to make clear it's not just the accountants at
16 FEI, it's things like customer care and a bunch of
17 other things that go into basically the costs that are
18 required to have a customer on the system. So it's
19 not just the finance and accounting piece.
20 Next, each of the costs and the functions
21 need to be classified. The classification process in
22 about what caused us to incur the cost.
23 So energy. Energy classification. A cost
24 is classified as energy if it’s a cost that was caused
25 --- we need to incur that cost to deliver a molecule
26 of gas to a customer. So we needed to get some gas to

1 the customer.
2 The demand related costs are the costs that
3 are required to deliver the peak day demand to a
4 customer. So at any one point a customer's going to
5 demand a whole bunch of gas, especially if it's cold
6 out, and the cost we incur to be able to get that gas
7 to the customer on their peak day, those are demand
8 related costs.
9 And finally, customer related costs. Those
10 are costs that we incur to attach a customer to the
11 system. Like meters and services, those are costs to
12 attach a customer to a system. Cost such as the
13 billing department, those are -- we have billing
14 department costs because we have customers attached to
15 the system.
16 Approximately half of the utility's costs
17 are classified as customer, and approximately the
18 other half is classified as demand. Very few costs
19 are classified as energy. And demand and customer
20 costs are predominantly fixed. If you think about all
21 of the pipe in the ground, all the facilities, and all
22 the staff at the billing centres, those costs are
23 predominately fixed and classified as demand in
24 customer.
25 To aid in classifying the costs, FEI has a
26 supporting study called the Minimum System Study. And

in addition to the Minimum System Study we use an adjuster called the peak load carrying capacity. The Minimum System Study is an attempt -- rather, a study that's used to be able to split up the distribution costs between demand and customer. So we have pipe that runs through the streets that ultimately attaches a customer. Some of that pipe exists because a customer exists. Some of that pipe exists because the customer demands a certain amount of gas at a certain amount of time. So the Minimum System Study really helps us split up the distribution plant and distribution costs between the customer and demand related components.

And then finally -- or next, rather, the classified costs need to be allocated across all our customer groups. The predominant allocators we use for that are peak day demand, and we use that to allocate our demand related costs. And then average customers, weighted in some cases, is used to allocate the customer related costs. And then finally, annual consumption is used to allocate any of the energy classified costs.

Proceeding Time 9:19 a.m. T6

And then finally, after all of our cost allocations are complete, the forecasts of revenues from the test years included in the COSA, and we

1 derive revenue to cost ratios. So, you can see up on
2 the slide there, we functionalize first, we classify
3 second, and finally we allocate. And then we check
4 those allocated costs against the revenues brought in
5 from the test year. And then we test the revenue to
6 cost ration against the range, the range of
7 reasonableness. If the costs, or if that R:C ratio
8 falls within a range of reasonableness, that customer
9 group is assumed to be paying their fair share of the
10 utility's costs.
11 It is important to note that the
12 methodologies to allocate costs in Fort Nelson's COSA,
13 are consistent with those that were used in FEI's
14 COSA, with a few minor exceptions as noted in the
15 application.
16 So this slide, and the next couple of
17 slides, show the resulting revenue-to-cost ratios for
18 our rate schedules for FEI and Fort Nelson. Fort
19 Nelson will be on the next slide. And it is just to
20 give you an idea of where we are going into this COSA
21 SRP as far as the results.
22 As you can see, most of the revenue-to-cost
23 ratios are within the range of reasonableness. The
24 upper table in particular are rate schedules that FEI
25 has that are based -- rather the rates are based on
26 their allocated costs. So you can see that most of

1 those are within the 90 to 110. We see rate schedule
2 6 is outside the range. Yeah.
3 And then the lower table are the rate
4 schedules that FEI has that are based on a value for
5 service, so they are a discount from firm. So, we
6 have discussed those in the application as well. But
7 it is important to note that those few rate schedules
8 in the lower table are not based on their allocated
9 costs, so we're not trying to target 100 percent, or
10 anything between the range of reasonablness. 90 to
11 110 on those ones, because they don’t attract a lot of
12 demand related costs, because they're interruptible
13 customers.
14 And this slide is Fort Nelson's COSA
15 results before proposals and rebalancing. As you can
16 see, we have a couple of rate schedules that are
17 within the 90 to 110 range, and a couple of our rate
18 schedules that are outside of the 90 to 110 range.
19 These two slides have been included to show
20 you that overall, our rate schedules are within, or
21 very close to the range of reasonableness, indicating
22 that these customer groups are paying their fair
23 share, or nearly their fair share of the utilities
24 costs.
25 As the agenda pointed out, we're going to
26 take a few minutes to talk through the EES report and

following up Elenchus report. So, FEI retained EES Consulting to review and assist in the development of its rate design proposals, including the COSA.

EES reviewed the COSA including functionalization, classification and allocation, and they also provided a jurisdictional review of COSA methodologies for comparison with seven other gas utilities in Canada and the Pacific Northwest. By and large, the EES review supported the methods and cost allcoations, and the results of FEI's COSA. Within their executive summary they indicate that the COSA developed by FEI is based on appropriate methodologies, and takes into account standard practice, past precedent, and cost causation. We find that the COSA follows standard utility practice, is generally consistent with past practice for the utility, and results are acceptable for purposes of setting just and reasonable rates for the utility. And FEI has proposed using a 90 to 110 revenue-to-cost ratio range of reasonableness. We consider this to be a reasonable range for use when considering the revenue to cost for FEI.

Proceeding Time 9:24 a.m. T07

Now, Elenchus will be presenting after FEI, so they have a few minutes or some slides to discuss. But I thought it was important to go over some of the

1 summary of their conclusions as well. So I've taken a
2 few slides to discuss some of the stuff that Elenchus
3 reviewed and found.
4 So, the BCUC retained Elenchus Research
5 Associates to review FEI's COSA and the term sheet is
6 included on record. Elenchus's report on the COSA is
7 included as Exhibit A2-2, and I've included on this
8 slide a summary of some of their findings. I'll let
9 you read them. But in summary, Elenchus reviewed both
10 FEI and Fort Nelson's COSAs. Elenchus views that the
11 methods that FEI has used to functionalize, classify,
12 and allocate costs in FEI's COSA are appropriate,
13 standard, and acceptable. Elenchus views that the
14 methods that FEI has used in Fort Nelson's COSA, to
15 functionalize, classify, and allocate costs are
16 appropriate, and that Elenchus supports the
17 adjustments made to Fort Nelson's test year in the
18 COSA.
19 Although Elenchus's report was generally
20 supportive of the methods and adjustments FEI has made
21 in the COSA, they brought up a couple of points in the
22 report that FEI considered. Elenchus did not agree
23 with how FEI included the Tilbury Expansion project in
24 the test year, and we're going to discuss that in a
25 few slides as one of the key areas of interest.
26 The second thing Elenchus noted that FEI

1 considered was that the PLCC used in conjunction with
2 Fort Nelson's minimum system study should be specific
3 to Fort Nelson.
4 So internally we had some discussion with
5 our rate design team, and we had some discussion with
6 EES on that fact, and FEI agreed that using a Fort
7 Nelson-specific PLCC in conjunction with the Fort
8 Nelson-specific minimum system was the correct
9 approach. So FEI made that change and filed an
10 evidentiary update for Fort Nelson's COSA and rate
11 design proposals as Exhibit B1-1-1.
12 And for the scope of the Elenchus report on
13 FEI's rate design, among other things, Elenchus was
14 asked to provide a discussion of how the concept of
15 range of reasonableness is dealt with in other
16 jurisdictions in relation to revenue-to-cost ratios,
17 and their application to rate design and rebalancing.
18 Firstly, a range is required. On page 34
19 of Exhibit A2-10, Elenchus writes:
20 "Regulators typically accept rates within a
21 range as constituting full recovery, since
22 it is recognized that cost allocation
23 studies are not precise."
24 Also on that same page:
25 "Derivations from 100 percent are likely to
26 be the results of imprecision in the

1 methodology as they are to be the results of
2 true cost differences."
3 And then finally on page 32 of Exhibit A2-10:
4 "Use of a range of reasonableness is the
5 most common approach to relating proposed
6 rates to the allocated costs."
7 All these statements would indicate that a range is
8 required when reviewing the R:C results of a utility.
9 **Proceeding Time 9:29 a.m. T8**
10 So, FEI spent some time reviewing the
11 evidence on record, the IRs, the technical IRs, the
12 Elenchus report, and so on. And we are attempting to
13 glean from that the key areas of interest that we
14 believe would be most appropriately discussed today.
15 The key areas of interest that FEI's
16 identified as the premier topics to discuss are the
17 COSA treatment of Tilbury Expansion Project; the
18 Minimum System Study; customer weighting factors,
19 including that of the meters and services, and the
20 administration and billing; and then finally, the
21 range of reasonableness. We'll talk about the
22 assumptions, judgments, simplifications, and the
23 estimations made in the COSA, and we'll have some
24 discussion of the peak day demand regression to get
25 people really familiar with one of the biggest -- or
26 one of the factors that we use for allocating our

1 costs in the COSA, the demand costs in the COSA.
2 COSA treatment of Tilbury expansion. So
3 this next item for discussion is really about how FEI
4 treated the Tilbury Expansion Project in the COSA and
5 why we did it that way. First, before we go on,
6 before I get into the details, I want to talk about
7 the known and measurable changes.
8 So, the COSA starts as a forecast. It
9 starts as a forecast of the test year, which is
10 basically 2016 revenue requirement for the utility.
11 Once we have that, we add to it, in the COSA, known
12 and measurable changes. These are the things that we
13 believe are material changes to the COSA that will be
14 in place in 2018 when these proposed rates will be
15 enacted. That was the original schedule.
16 So, we look at the COSA, start with the
17 test year, and then we add in things that we know are
18 going to happen over the next few years to come to --
19 to help us eventually do the COSA, figure out what
20 everyone's allocated costs are, and then ultimately do
21 our rate proposals from that.
22 So in an application Section 6.3.2.3, FEI
23 discusses how it treated the Tilbury Expansion
24 Project. The Tilbury Expansion Project, which is the
25 only project that has associated revenues -- with it
26 FEI adopted a different approach. So what FEI did was

1 we looked at Tilbury Expansion Project over a number
2 of years. Now, this is a project that's going in,
3 going to be in rate-base in 2018. It's going to bring
4 with it a number of costs, but it's also going to
5 bring with it some revenue, a revenue stream. Now,
6 that revenue stream is going to grow over time. We
7 expect that to grow over time as this asset in
8 particular is brought on to develop the LNG market, or
9 rather, to serve the LNG market.
10 So the forecast we had included in the COSA
11 included a ten-year view of costs and revenues for
12 Tilbury. And the reason why we did this is to get a
13 sense of a longer-term view that Tilbury would have on
14 customers' rates, or, rather, on the COSA and
15 ultimately the allocation of costs. As described
16 earlier, Elenchus's opinion was that Tilbury should
17 not be treated like this and simply rolled in using
18 the 2018 costs and revenues.
19 So using that approach, where we include
20 the known and measurable changes of Tilbury for the
21 first year of operations, shifts some costs between
22 rate schedules as shown in BCUC IR 1.9.3.1 where the
23 cost allocations are moved a little and the revenue-
24 to-cost ratios change a little bit within plus or
25 minus two percent. So the table on the slide there,
26 if we used a rolled-in approach, basically if we used

1 the first year of Tilbury's costs and revenues, it
2 would change the allocations and the -- sorry, in the
3 COSA and we'd end up with some slightly different
4 revenue-to-cost ratios.
5 **Proceeding Time 9:33 a.m. T09**
6 So, FEI considered that a longer-term
7 levelized approach is the most reasonable method for
8 including Tilbury Expansion in the COSA. Because of
9 the nature of the asset, and the fact that LNG demand,
10 and consequently revenues, will be phased in to
11 capacity over the first ten years. With respect to
12 Tilbury Expansion, by using a ten-year approach, the
13 next COSA study result should be similar to this COSA
14 study results, therefore maintaining stability in the
15 cost allocations, the R:C ratios, and ultimately
16 customers' rates. So the idea was, let's bring in
17 Tilbury as -- we would expect to see it over the next
18 ten years, so when we do the COSA study again, it
19 should produce similar cost allocation results and
20 ultimately keeping rates for our customers a little
21 more stable than if we just included the 2018 costs in
22 the COSA today.
23 The next key area of interest is the
24 minimum system study. Before we go into the content
25 of the slide, I'd like to talk a little bit about what
26 is a minimum system study and why do we need it.

The study is used to recognize that a portion of FEI's distribution system is in place to connect customers and a portion is in place to meet customers' peak day demand. The study is used to split the cost of the distribution system into these two components.

To calculate the cost, the customer-related costs of the distribution system, FEI values the entire system, the entire distribution system, at FEI's minimum standard, which is 60 millimetre polyethylene pipe. The minimum value — so this value — is divided by the system as existing replacement cost. So we take the minimum system, assuming all pipe is 60 millimetre PE, and we divide it by basically the replacement cost of the pipe, of the pipe that's in place today. So what that does is produces a percentage that's considered customer-related. So the minimum system study produces that percentage that's customer-related. And for us, that result was 30 percent. So, 30 percent of our distribution-related costs for mains and services is 30 percent.

FEI uses this 30 percent to classify the distribution system in the COSA between customer-related and then demand-related. So demand-related, 70 percent.

1 Now a little bit on the PLCC, the peak load
2 carrying capacity adjustment that's made in
3 conjunction with the minimum system. So, the PLCC is
4 used to determine the theoretical capacity of the
5 minimum system. So we use 60 millimetre polyethylene
6 pipe as the minimum system, and we know there is a
7 capacity in that. We know there is an ability to
8 carry some capacity of gas.
9 The PLCC is used to adjust the demand
10 allocator downward to eliminate the demand-related
11 costs that our customers are already paying, that's
12 embedded in the customer-related cost component of the
13 distribution system. So, 30 percent of the
14 distribution system is allocated -- 30 percent of the
15 distribution system's cost is allocated -- or,
16 classified as customer. Recognizing that adds some
17 capacity, we reduce the demand-related -- the demand
18 allocation factor so that they're not double-paying.
19
20 **Proceeding Time 9:37 a.m. T10**
21 So the PLCC adjustment reduces the demand
22 allocator recognizing that customers are already
23 paying for the demand-related costs that are imbedded
24 in the customer-related component of the distribution
25 system. So, minimum system, plus PLCC helps us
26 discern how much of the customer-related component and

1 the demand-related component of the distribution
2 system.
3 FEI has used 60mm polyethelene pipe to
4 value the minimum system, because that is our minimum
5 standard for distribution pipe as identifed in
6 appendix 6-6 of the application. There are few
7 exceptions to this standard, which we have identified
8 in BCUC IR 1.7.2.1. On page 15 of Exhibit A2-2,
9 Elenchus wrote:
10 "Elenchus reviewed the MSS and PLCC
11 adjustment study done for FEI and agrees
12 with how FEI has conducted the study and
13 used the results."
14 Utilities that apply -- sorry. Elenchus's
15 response to BCUC IR 4.2, they write:
16 "Utilities that apply the minimum system
17 method to classify distribution mains
18 between customer and demand related use use
19 the size of the mains currently being
20 installed. The key considerations should be
21 the availability of appropriate cost date."
22 FEI's current minimum standard is 60mm. We
23 have more costing data on 60mm, so we have better
24 estimates for the minimum system study to use to value
25 that minimum system.
26 Approximately 70 percent of the mains

1 installed over the last two years have been 60mm PE,
2 and about 5 percent have been 42mm PE. So the reason
3 why I bring up 42mm is there were some questions
4 around "Shouldn't you be valuing your minimum system
5 around 42?" Well, we had the most costing data on the
6 60mm, and it is actually the minimum standard today.
7 So, it makes sense to use the minimum standard with
8 the best costing data, the one that we're putting in
9 place today. And the PLCC adjustment helps recognize
10 that there is some capacity in there already. So it
11 basically, the PLC and the MSS -- the minimum system
12 study with the PLCC help get us to a better customer
13 and demand related cost regardless of what millimetre
14 you use as your minimum system in the study.
15 And finally, in Elenchus's response to BCUC
16 IR 5.1, they write:
17 "Elenchus considers the 60mm to be an
18 appropriate minimum systems standard."
19 Since 2008 the cost of FEI's distribution
20 system have been made up, or have been more and more
21 influenced by the cost of the 60mm PE. And for the
22 forseeable future, 60mm pipe will continue to make up
23 more of FEI's distribution plant costs. The purpose
24 of the minimum system study is to split the costs of
25 the distribution system. For this reason, producing a
26 minimum system study using anything but the 60mm

1 minimum standard is divorcing the study results from
2 the system costs. For the last two decades FEI has
3 consistently used the standard in place at the time to
4 produce the minimum system study in support of its
5 rate design applciations, and it is for these reasons
6 the appropriate minimum standard to use when producing
7 the study is 60mm.
8 **Proceeding Time 9:42 a.m. T11**
9 The next key area of interest was our
10 customer waiting factors. In the past FEI has used
11 one factor, the customer weighting factor for metres
12 and services essentially to allocate its metres and
13 services costs, and its customer accounting costs.
14 FEI now uses two customer weighting factors
15 when allocating its customer related costs. FEI did
16 this for both the 2012 amalgamation and common rates
17 application, and for this application. One of the
18 factors used in this application was the customer
19 weighting factor for meters and services, and is used
20 to allocate the meters and services cost in the COSA.
21 The other is the customer weighting factor for
22 administration and billing, which is used to allocate
23 customer accounting and marketing costs. This slide
24 here describes the customer weighting factor for
25 meters and services.
26 This factor differentiates that the cost to

connect small customers and large customers is different. So, it recognizes that the cost to connect to residential customer from a meters and services standpoint is different than the cost to connect a large industrial customer from a meters and services standpoint.

The ratio is calculated as a ratio relative to the residential schedule, so a residential schedule is the smallest cost to connect somebody, so the ratio is one-to-one, and larger customers which have larger meter sets and services have a weighting that is higher than one-to-one, so they could have a weighting that is -- there is a number in the next couple of slides, but they'll be greater than one. So what it does is it recognizes that we have one plan account, with all the meters and services costs in it, and we need to take that and spread it among all our customer groups. And so this factor helps recognize that it is less expensive to connect residential customers than it is to connect commercial and industrial customers from an assets and a meters and service standpoint.

The weightings can be found in sections 6.3.6.1 table 6-15. I have the table in the next slide, next couple slides, so we can take a look at them there.

The next weighting factor that I talked

about in the previous slide is the customer weighting factor for administration and billing. This factor recognizes that the commercial and industrial customers typically require more administration and billing effort. Again, factors are relative to residential class. So, residential is a one, commercial customers tend to be around 43, and sorry, commercial/industrial 43, and those are transport are 75.

So, the factors consider the use of remote meter reading, and the frequency of meter reading, the method of collecting and retaining data, the time spent responding to customer inquiries, the fact that we have dedicated account managers for both our commercial and industrial customers, the resources dedicated to billing, measurement and marketing, and then finally some of the marketing programs in place for the larger customers.

The factors are used to allocate customer accounting and marketing costs in the COSA. Again, factors there, we have all these customer costs, one big bucket would be the factors used to recognize commercial and industrial customers tend to have more effort involved in billing and administration and marketing programs. The factor is really about relative effort, so it is all relative to rate

1 schedule 1.
2 I have a second slide on this that I'll
3 talk you through. So on the left we have our Table 6-
4 15 from the application. So, our rate schedule is in
5 the first column. The second column they call it, we
6 named it "customer weighting factor", but it's really
7 the customer weighting factor from meters and
8 services. So, that is the one that recognizes that
9 small customers are a little less costly to connect
10 than larger customers. So that's the second cone.
11 **Proceeding Time 9:46 a.m. T12**
12 In the third cone is the customer weighting
13 factor for administration and billing. So you can
14 see, generally it's one for the smaller rate
15 schedules. As we get into the larger industrials, it
16 turns into 43, and then as we get into the industrial
17 -- or, sorry, transport rate schedules, rather, it
18 turns into 75.
19 So, a little bit more on the customer
20 weighting factor for admin and billing, as there were
21 a few questions regarding how they were derived.
22 So, another way to look at them is to look
23 at the relative effort that we put in. So, on the
24 right-hand side of the slide, I put a table up there
25 to kind of describe the ratio of our industrials to
26 residential and commercial. So at the right at the

1 top, we have the number of residential and commercial
2 customers and then right after that we have about --
3 our call centre staff. So our call centre staff are
4 there in place to answer questions and take calls for
5 our residential and commercial customers.
6 So if you look at a ratio of call centre
7 staff to customers, it's 0.00025.
8 Then we have our industrial customers. We
9 have about 2,650 industrial customers, and 31 key
10 account managers, excluding the marketing folks. So
11 if you look at the effort, or the ratio of key account
12 managers to our industrial customers, it's 0.01169.
13 So when you just make a relative ratio to
14 one -- so basically taking the 0.01169, dividing it by
15 the 0.00025, you get a 46 to 1.
16 So just looking at the call centre staff,
17 we're looking at about 46 to 1 relative effort for
18 taking calls, for our residential/commercial group,
19 versus our industrial group.
20 So 46 is close to the 43 that was derived
21 back in 2011 for our amalgamation application. And
22 also reviewed for this application.
23 So the second piece is -- the second table
24 on the bottom right there is billing. So we have
25 mass-market customers of about 977,000. And we have
26 about 43 billing staff. So, as you can see, the staff

1 to customer ratio for billing is quite small, 0.00004,
2 for the mass market.
3 And then we have our transport customers.
4 So those are the customers that basically bring their
5 own gas onto the system. They require a lot of daily
6 measurement, daily reads, so the marketers can manage
7 their gas.
8 So we have about 2,383 transport customers,
9 and we have 8 billing and measurement associates that
10 basically assist in the billing and measurement for
11 those folks. So their billing and measurement ratio
12 to transport customers is 0.003336.
13 So for this one, when you do the relative
14 weighting of transport to mass market, you get 76. So
15 our transport customers require about 76 times the
16 effort as our mass market customers for billing.
17 So as you can see on the table that we used
18 in the application -- rather on the factors we used in
19 the application, we had 75. So 76 is pretty close to
20 75.
21 This is an indication that the weighting
22 factors for admin and billing are reasonable and
23 appropriate.
24 So the next key area of interest was the
25 range of reasonableness. We had lots of questions on
26 the range of reasonableness, and also this is part of

1 the scope as outlined by the Commission panel.
2 So, over the next few slides, I'll speak to
3 the need for a range, when assessing the results of
4 the COSA, and why a 90 to 110 range is appropriate for
5 FEI.
6 So, why is a range needed when assessing
7 the results of the COSA in assessing whether a
8 customer group is paying their fair share of costs?
9 Well, when producing the COSA study, a forecast is
10 used.
11 **Proceeding Time 9:51 a.m. T13**
12 So we use the 2016 revenue requirement, and
13 turned that into test year we add in a forecast of
14 known and measurable changes. You know, our forecasts
15 are approved, so the revenue requirement is approved.
16 The known and measurable ones aren't particularly
17 approved, but it's a forecast. So we know the costs
18 and/or the revenues may come in different than the
19 forecast, and will likely come in different than the
20 forecast. So when looking at, when considering the
21 COSA you've got to remember it starts with a forecast.
22 Then we have our supporting studies. While
23 indicative and necessary to develop reasonable cost
24 allocations, are ultimately not perfect. So the
25 minimum system study, we use a minimum standard in
26 place, we look at the minimum value of the system, and

1 use replacement costs. We do the division, and we get
2 a reasonable estimate of the customer and demand
3 related component for a minimum system. But it's not
4 perfect.
5 We have load data. Although it's
6 reasonable, we have to recognize that the means to
7 derive our peak day demand is not a perfect predictor.
8 And we'll discuss this more in a few slides. Most of
9 the utilities costs are common, as I spoke to earlier,
10 and difficult to accurately identify which customer
11 group caused those costs.
12 Also, to produce the COSA we've made
13 assumptions, judgments, simplifications, and
14 estimations, which we'll talk to a few examples in the
15 next couple slides. It's basically the COSA is a
16 really good tool for figuring out allocated costs, but
17 ultimately it's not perfect and it's not super
18 precise. So, therefore, a range is required to assess
19 whether the revenues collected cover the allocated
20 costs.
21 So first we're going to talk a little bit
22 about assumptions, judgments, simplifications, and
23 estimations in the COSA. And I'll use this time to go
24 through a few examples just to give you a flavour of
25 what these things are. As I spoke to earlier, the
26 COSA is based on a test year. And this is consistent

with FEI's past practice. We've always used a test year, basically a forecast year, to produce the COSA.

Actual costs and revenues will be different. And even if the costs were perfectly allocated, even if that was possible, the revenues would certainly be different. The actual revenues would certainly be different, so you need this range to take a look at your final results.

Judgment. The EES report identifies three demand allocators that could be used. There's coincident peak, non-coincident peak, and average and excess. And any one of these, when used, will allocate costs a little differently. FEI has used all three in the past for its 1993 Phase B and 1996 rate design applications to demonstrate that allocation of demand costs can be performed in a number of ways.

Since '01 FEI has used the coincident peak method and the one that we use today, as it best reflects how the utility plans and builds its distribution system. So we continue to use the CP method since '01 because we feel it's the best indicator of how we plan, and build, and basically incur costs for our system.

Simplifications. In reality, as I spoke to earlier, most of the costs are shared, right? Everything from distribution mains in the streets, all

1 the way up to our interconnection points with upstream
2 pipelines. Arguably the only costs that are specific
3 to a customer is the meter and the service. Yet, all
4 these costs need to be allocated in the COSA. They
5 need to be allocated across all of our rate schedules
6 or customer groups.
7 FEI uses functionalization classification
8 allocation described in section 6. These methods are
9 consistent with past practice and consistent with --
10 sorry, rather, and consistent with industry standards.
11 **Proceeding Time 9:55 a.m. T14**
12 They were reviewed both by EES and Elenchus
13 Research Associates. However, there are other methods
14 for allocating costs as identified by EES in their
15 jurisdictional review. All these methods will produce
16 different cost allocations, and none of them will
17 really capture which customer group truly causes the
18 costs, because that is unattainable at a reasonable
19 cost.
20 And then finally, we used estimations. FEI
21 allocates many of its costs, demand-related costs,
22 using peak day demand. The peak day demand of each
23 customer group is an estimation and we'll talk about
24 how we get that estimation on the next slide.
25 So flowing from the last slide, I want to
26 take some time with the calculation of peak day demand

that we use to allocate both directly and indirectly about half of our costs. I said earlier about half our costs are classified as demand, and half as customer. The peak day demand allocator is used in a lot of cases to allocate the demand-related costs in the COSA.

So, once we go through the details of how we derive this peak day demand, it should be evident of how the gas utility's load data is not quite as accurate as that of an electric utility, and why a wider range of reasonableness is appropriate.

So the first thing we do is, we acquire monthly -- we estimate monthly consumption. So we require the monthly consumption from our billing group. This data has both actuals and estimates. So, we do these regressions based on consumption in a month, and at temperature in a month. You think the -- we don't go read everyone's meters just on the first day of the month, so -- or the last day of the month to get a month of consumption. We actually read them right through the month. So, we have all these different read datas through the month, and then we -- in conjunction with those, we have unbilled data, or unbilled consumption estimates as well. So, the first thing that's done is, we get -- we try to get January -- like, January, February, March, April. We get

these consumption months, but recognizing, some of it's actual and some of it's called unbilled consumption — basically an estimate of what those customers will consume for the balance of the month. So we start with an estimate of consumption.

Then, we turn that into an average daily consumption, because we're trying to ultimately derive a peak day demand. So we take that monthly consumption and we divide it by the number of days in a month. So we create an average.

Then we regress that -- or rather, we pick up the temperature for the month, which is also an average. So we have our average daily consumption, and average daily temperature and then we plot those things. We don't always plot them, but we create a regression equation.

So we plot the average daily consumption and the average monthly temperature. So now I'll turn to the graph, and I'll explain to you all the pieces of the graph, so you can get a sense of where we are.

So the graph is the plot of consumption, average consumption and average temperature by month. You see on the bottom axis, the X-axis there, is temperature in Celsius. There's a zero, zero Celsius in the middle. Negative degrees to the left, and positive to the right. And up the middle is the daily

use per customer in GJs.

So the dots, the blue dots, are those data points that we have. We have monthly data points of average daily temperature and average consumption. So as you can see, they fall within 5 to 20 degrees, all the data, because that's our typical temperatures.

Now, we know we get colder temperatures, but generally they're in the middle -- they're in that range there, plus also we remember we averaged before, because we only have monthly consumption, so we had to have average temperatures. So we have a couple of averages there that we're plotting on the graph.

And then what we do is -- okay, what else do we get? You got the temperature, consumption, we got the data points. And then we create a regression equation, basically a linear regression equation, that draws a line through those points and estimates -- we use that regression equation to estimate the peak day demand on the coldest day in 20 years.

So, we need to build our system to be able to serve our customers at the coldest temperature. The reason being is, if we didn't, people would lose their gas -- we wouldn't be able to serve them the gas when they need it. Ultimately, you know, in a lot of cases the pilot light's going out, and there's a big safety hazard. We have to go out and re-light

1 everyone. That would be -- I don't even know how to
2 explain. It would be impossible to go and re-light
3 everyone in a section of the Lower Mainland, or the
4 Lower Mainland itself. But the idea is we need to
5 serve, we need to be able to build pipe, put it in the
6 ground to serve the peak day because we can't afford
7 to have all the pilot lights go out in the Lower
8 Mainland at one time.
9 **Proceeding Time 10:01 a.m. T15**
10 So, anyways, my point is that we have a
11 bunch of points for which we draw regression line
12 through, trying to estimate out a peak day demand.
13 So, we know that regression line, that R-squared is
14 good, but we know it is also a good predictor of the
15 usage according to the temperature within the data
16 range itself. And as you move further away from the
17 data range, the regression equation, rather the
18 regression line gets less valuable as a predictor.
19 But at this point, this is what we have, and so we
20 push it out to our peak day temperature and estimate
21 the daily consumption.
22 MR. PERTTULA: Rick, can I just comment. Just so you
23 know that graph is actually on the record. It is in
24 appendix 6-7 of the application, page 2. So, the only
25 thing that Rick has added is that red x to the graph
26 that is already on the record.

1 MR. GOSSELIN: So, from our peak day demand, what we
2 expect this customer in particular to use on the peak
3 day, we create a load factor. So, the load factor is
4 just looking at -- it's a relationship between peak
5 day demand and average consumption. The peak day
6 demand is derived in the previous step, used to
7 allocate load -- sorry, the load factor is used to
8 calcuate load factor by dividing annual consumption by
9 the peak day demand multiplied by 365. So, if every
10 day was peak in the year, here is the average
11 consumption. So, the average, divided by the peak, is
12 essentially the load factor that is used.
13 So, we do this for each of our heat
14 sensitive rate schedules in each of our regions. So,
15 we have Lower Mainland, Inland, Columbia, VI,
16 Whistler; all those have different peak day
17 temperatures. It is important that we recognize it is
18 colder in some areas than others. So, we do this
19 regression for each of those heat sensitive rate
20 schedules in each of the regions. And then what we do
21 is we do a weighted average of all those regions to
22 get a weighted average load factor. And then we use a
23 three year average to knock out any data anomalies.
24 So a three years average load factor, and then we take
25 that to the COSA and derive our peak day demand from
26 the test year consumption using this average load

1 factor. And that is used, that peak day demand
2 derived in this manner is used to allocate many of our
3 demand related costs in the COSA.
4 In the case of BC Electric Utilities, there
5 is a relative, certainly, in the load research. The
6 equivalent level of certainty doesn't exist for the
7 natural gas utilities. FEI believes that there is
8 sufficient imprecision in the allocator to warrant a
9 range of reasonableness wider than 95-105.
10 I know that was a lot of information. Does
11 anyone have any questions on it? Yes, Chris.
12 MR. WEAFER: Chris Weafer, Commercial Energy Consumers.
13 Yeah, we've had a fairly lengthy process between the
14 workshops and the application process and the IRs, so
15 there is a lot on the record. In terms of the topics
16 for today, the primary concern of the CEC is the range
17 of reasonableness position being taken by the company,
18 and that has been the case since the start of the
19 workshop. So, just a couple of areas of questioning
20 on that.
21 Can you access IRs and put them on the
22 screen?
23 MR. GOSSELIN: Pardon me?
24 MR. WEAFER: Can you access information requests and put
25 them on the screen?
26 MR. GOSSELIN: I'm sorry, I didn't hear that.

1 MR. WEAFER: Can you access information requests, and put
2 them on the screen?
3 MR. GOSSELIN: Oh, I don't think so.
4 MR. WEAFER: Okay, fair enough. The key IR that I just
5 want to talk about a little bit, and get your response
6 is the CEC IR and it is from Exhibit B-11.
7 **Proceeding Time 10:06 a.m. T16**
8 It's CEC IR 1.19.3. And simply put -- yes, do take the
9 time to pull it out, please. So, again, the reference
10 is Exhibit B-11, CEC IR 1.19.3.
11 THE CHAIRPERSON: Mr. Weafer, just a --
12 MR. WEAFER: Yes?
13 THE CHAIRPERSON: Is this a clarifying question related
14 to the presentation or is this a more detailed
15 question that might be better asked once the
16 presentation is complete?
17 MR. WEAFER: Oh, I'm sorry. I thought he had completed
18 the presentation and was asking for questions, so we
19 are moving into a more detailed question.
20 THE CHAIRPERSON: Okay, so --
21 MR. WEAFER: If I'm jumping the gun I'll step back.
22 THE CHAIRPERSON: Okay, thank you.
23 MR. GOSSELIN: Thank you, panel. Sorry, Chris.
24 MR. WEAFER: I misunderstood. I thought you had closed.
25 I'm sorry.
26 MR. GOSSELIN: No, not yet. Nearly closed though.

1 And finally, the last slide I have here is
2 R:C at -- it talks about the range of reasonableness
3 and 90-110 ratio or range of reasonables that we've
4 used. And finally, to summarize why a 90-110 range is
5 reasonable and appropriate for FEI, it's consistent
6 with past practice.
7 So we have -- the Commission has accepted
8 90-110 for FEI in the past. The range used in the
9 1993 Phase B was based on past precedents, which
10 implies that the Commission used a 90-110 for rate
11 design proceedings prior to '93 for FEI. And we have
12 more detail on FEI's response to BCUC IR 1.14.1 on
13 that. As stated in BCUC
14 -- or, sorry. As stated in FEI's response to BCUC
15 technical IR 6.1, FEI considers that the 2016 COSA is
16 as accurate as the 1993 COSA.
17 Again, back to the COSA. What happens is
18 the COSA -- we have our assumptions, judgments,
19 simplifications, the peak day demand method,
20 estimation is similar to what we used in 1993. So we
21 answered that response. We believe that the FEI
22 COSA this year is about as accurate as the 1993 with
23 respect to peak day estimations and cost allocations.
24 Many other jurisdictions use R:C. Elenchus
25 noted in their response to BCOAPO 2.11.1 that the
26 review did not find any other Canadian utility using

1 margin to cost ratios. So that's the reason for the
2 R:C.
3 And when considering rebalancing we must be
4 mindful of the impact that our customers will
5 experience. Since our customers pay for both delivery
6 and revenue -- sorry, delivery and gas itself, using
7 the the R:C as a basis for rebalancing reflects what
8 they'll experience. So our customers experience
9 revenue changes, so we should be using the revenue to
10 cost ratio when assessing rebalancing.
11 For all the reasons I've identified in the
12 last few slides, and for consistency with past
13 practice, and based on the precedent decisions as
14 identified in the slides, the appropriate range of
15 reasonableness for FEI is 90-110, we believe is 90-
16 110.
17 And that concludes our presentations.
18 THE CHAIRPERSON: Thank you. We will take a ten-minute
19 break, and then we'll hear from Elenchus.
20 (PROCEEDINGS ADJOURNED AT 10:10 A.M.)
21 (PROCEEDINGS RESUMED AT 10:22 A.M.) **T17/18**
22 THE CHAIRPERSON: Okay, let's get started. Elenchus, you
23 are going to present.
24 MR. ROGER: Thank you. My name is Michael Roger, I am an
25 associate consultant with Elenchus, and I will start
26 the presentation, and then John Todd will continue the

1 presentation. We have a very short presentation, and
2 some of the things that I will be saying, or John will
3 be saying, probably will be repeated from what Mr.
4 Gosselin presented. And we will just be giving a high
5 level summary of the Elenchus cost allocation report,
6 which is Exhibit A2-2, and section 7 of the Elenchus
7 rate design report, which is Exhibit A2-10.
8 What we did, at Elenchus, is we reviewed
9 the cost allcoation that FEI filed with the
10 Commission. And we looked at the traditional approach
11 that utilities follow in cost allocation studies, and
12 like Mr. Gosselin explained, we found that what they
13 do is follow the traditional approach in doing cost
14 allocation study. They did a functionalization,
15 categorization, and allocation of the revenue
16 requirements and assets which are the three main steps
17 in doing a cost allocation study, in trying to split
18 mostly shared assets and expenses among customer
19 classes.
20 There is another approach that can be
21 taken, which is called a direct allocation, and if
22 their assets were expensive, they are attributed to a
23 particular customer class, they can bypass the cost
24 allocation process and can be allocated directly to
25 the customer class. And FEI did that. For example,
26 for Fort Nelson, for industrial customer meter

1 stations were assigned directly to RS25, so they
2 follow that approach also.
3 One of the things that we looked at also,
4 when we look at the cost allocation report, and it is
5 explained in pages 4 and 5 of our report, is the data
6 that was used in the cost allocation study.
7 Traditionally data could be historical or forward
8 looking, and FEI looked at forward looking data. As
9 utilities do, they used their accounting system, and
10 they used forecast of sales as the data required in
11 the cost allocation studies. All those things are
12 used traditionally by utilities in doing cost
13 allocation studies, and we agree with the way that
14 they've done it.
15 A number of interrogatories we received
16 with respect to the data, ask if we thought that the
17 data was of good quality, and we said yes, based on
18 our information, what we know about FEI, we think that
19 the data that they're using is of good quality.
20 And the other issue that was asked also was
21 about the frequency that utilities undertake in doing
22 cost allocation studies. Based on our experiences,
23 utilities usually do a cost allocation study as part
24 of their rate design approach, and it is traditionally
25 around every five years, maybe. It is a very
26 extensive exercise, and it usually is not done every

1 year. But that is another type of question that we
2 received is how often should cost of service
3 allocation studies being done.
4 **Proceeding Time 10:27 a.m. T19**
5 The objective in doing cost allocation
6 studies, what the industry usually looks at is what's
7 called the Bonbright principles in cost allocation
8 studies. And James Bonbright identified ten
9 principles, cost allocation principles, that are cost-
10 related, revenue-related, and practical-related.
11 And FEI in their application identified
12 eight principles. And when we look at those
13 principles we found that they are equivalent to the
14 principles that Bonbright identified. So from our
15 perspective, FEI follows similar principles that
16 Bonbright follows in doing cost allocation studies.
17 As I said, we found out that in general the
18 cost allocation proposed by FEI followed the standard
19 practices, but we found four areas where we had
20 comments, in the way that FEI is proposing to do their
21 cost allocation studies. And again, Mr. Gosselin
22 identified some of them so I'm just going to repeat
23 what our views were, and Mr. Gosselin explained it.
24 The first one was that caught our attention
25 was that the Mount Hayes storage facility. Based on
26 FEI's description, it's a dual function facility. It

1 provides a facility for distribution and midstream for
2 storage and transmission. And what FEI proposed to do
3 is take some of those costs and functionalize them as
4 transmission.
5 When we look at other utilities and how
6 they deal with storage facilities, it's not something
7 that we found other utilities. But based on the
8 explanation that FEI provided of why they treat Mount
9 Hayes that way by splitting it between two functions,
10 delivery and storage and transmission, we think it's
11 appropriate, what FEI is doing, even though we have
12 not seen anybody else doing it that way.
13 And that's now line in Section 4.1.3, page
14 10 of the cost allocation report.
15 Another area that we identified that was
16 slightly different, the way FEI proposed to do it, is
17 that distribution demand-related costs are usually
18 allocated based on non-coincident demand. FEI
19 proposes doing the allocation based on their
20 coincident demand. And we asked FEI when we were
21 reviewing the methodology at this particular point and
22 they provided us with a response that is Appendix A in
23 our report, and they explained to us that first of all
24 they don't have the data to do non-coincident demand,
25 but they also say that around 80 percent of their load
26 is heat-sensitive. And they feel that because they're

1 heat-sensitive loads, their non-coincident peak would
2 be equivalent to their coincident peak.
3 So even if they would try to estimate a
4 non-coincident peak by the class, the result would be
5 very similar to the result, what they're using by
6 using coincident peak allocation.
7 So we've accepted that explanation from
8 FEI. And that again is in our report in Section
9 4.3.4, page 17.
10 The other aspect that Mr. Gosselin referred
11 to that was how they treat the Tilbury Expansion
12 project. What they are doing is, they're looking at a
13 ten-year horizon and levelizing the costs for revenues
14 and costs for that project. Based on our experiences,
15 we've seen the utilities when they have new projects
16 coming into service. In the first year they include
17 in the first year the cost and revenues for that
18 particular year. And every year after that, they do
19 the same thing. They don't levelize and bring the
20 revenues and costs forward.
21 So that's an area that, for us it looks
22 different than what other utilities are doing, and Mr.
23 Gosselin explained why the FEI is doing it that way,
24 and also explained the impact on how costs on asset
25 will be allocated to the different customer classes
26 and revenue- to-cost rations

1 **Proceeding Time 10:30 a.m. T20**
2 Finally, we've identified PLCC adjustment,
3 and Mr. Gosselin referred to that. When we look at
4 the minimum system messer is and what the peak load
5 carrying capacity is, we notice that in the case of
6 Fort Nelson. The minimum system results were used for
7 Fort Nelson, but the PLCC adjustment were the ones
8 used for FEI. And we brought that to their attention,
9 and Mr. Gosselin explained they looked at it with
10 their consultant EES, and they agreed that the PLCC
11 adjustment for Fort Nelson should reflect their own
12 characteristics, and they updated their evidence on
13 April 7th, in Exhibit B-1-1-1, where they are using for
14 Fort Nelson the PLCC that reflects the Fort Nelson
15 characteristics, and not FEI.
16 So, those are the four areas that we've
17 identified based on our review that FEI proposals were
18 slightly different than what we've seen based on our
19 experience. Some of them they've explained to us why
20 they've done it, we've accepted their explanations.
21 In others, we think that it is not what other
22 utilities are doing. But as Mr. Gosselin said, there
23 are a lot of assumptions going on in cost allocation
24 studies, and it is correct for a utility to reflect
25 their own circumstance in their study. Cost
26 allocation is more art than science. There is not

1 going to be one right answer and a wrong answer. But,
2 it should reflect their own utility circumstances.
3 I think Mr. Todd is going to continue then
4 with the next section, which is the rate design
5 report, and section 7 of the report.
6 MR. TODD: I'll take any excuse to stretch my legs, even
7 though it will be for about two minutes. This will be
8 very quick.
9 The report overall had a number of sections
10 laid out on the slide. I won't read through them.
11 All that is within scope for today's process is
12 section 7, revenue cost ratio range of reasonableness.
13 As you are well aware, FEI uses a range of
14 90 to 110 percent. We did our survey of the ranges of
15 reasonableness used elsewhere by gas utilities. Those
16 are set out on the slide. Wider ranges are used for
17 electricity. Saying what is correct in terms of a
18 range of reasonableness is impossible. It is the
19 judgement of a regulator as to what is an appropriate
20 range. I would like to add some context to, at least,
21 our view of what is the purpose of the range of
22 reasonableness.
23 There is a lot of uncertainty. I would say
24 the same things as FEI has said about the causes of
25 the uncertainty. The one way of viewing the purpose
26 of a range of reasonableness, is what level of proof

1 do you need to say that differential rates --
2 differential rate increases are justified? What a
3 range of reasonableness does is says unless you're
4 outside the range, everybody gets the same rate
5 increase. So, in effect, it is a level -- speaking to
6 the lawyers, it is a level of a burden of proof around
7 saying certain classes should have a higher rate
8 increase than other classes, or some have a lower rate
9 increase than other classes. And the broader the
10 range, the more stringent the test that says it's
11 reasonable to have differential rate increases.
12 **Proceeding Time 10:36 a.m. T21**
13 Our view is that to have the 90 to 110 is
14 not unreasonable as a range – unreasonable is a range
15 of reasonableness – because of the various factors
16 which create imprecision and uncertainty. The mere
17 fact -- it's all common costs means that there is a
18 certain amount of kind of arbitrariness to the way the
19 costs are split up. And to actually drive
20 differential rate increases, you need a fairly strong
21 case, if I can put it that way.
22 It would also not be unreasonable to reduce
23 that range to 95 to 105. The important thing is, the
24 range is symmetric. And an important factor is
25 consistency through time. You wouldn't want to be
26 changing a range of reasonableness. So if that shifts

1 the burden of expectation in favour of continuing with
2 the range used in the past. But at the same time, a
3 change would not be unreasonable.
4 I think our -- when I read back through our
5 evidence, I don't think it was totally clear about the
6 margin to cost ratios. There is a source of potential
7 confusion because of labeling that is used. And what
8 this slide emphasizes, and I don't think came clearly
9 through the evidence, although it's kind of varied in
10 there, we said no other utility surveyed uses FEI's
11 term of marginal cost ratios.
12 FEI's marginal cost ratios excludes pass
13 cost throughs. But when you look at what the other
14 utilities are using in terms of a revenue-to-cost
15 ratio, they have various exclusions, including some
16 that exclude exactly the same pass-throughs. So,
17 while other utilities have not used margin to cost
18 ratio term, they have used revenue to cost ratios that
19 are defined in a way that is consistent with the M-to-
20 C ratio. Therefore, the M-to-C ratio conceptually is
21 not unusual. And that's laid out in a couple of -- I
22 think the BCOAPO 11.4, and the report at page 35.
23 Hopefully that's clear from our survey,
24 which identifies the exclusions of some of the
25 different companies. I don't think that was made
26 clear, and I think, in the presentation from FEI, the

1 misconception that there aren't M:C's there.
2 Everybody just uses an R:C except conceptually they
3 do.
4 So what we've said -- where I just cited
5 the report, page 2 -- sorry, report number 2, page 35,
6 I think is worth emphasizing in terms of our position,
7 make sure it's not misunderstood. The M:C ratio has
8 merit as a primary reference. Our bias is, you've got
9 to -- you have to have one as a primary reference.
10 The M:C ratio excludes things that are pass-throughs.
11 Therefore, it makes sense to use the M:C ratio. And I
12 note that in other jurisdictions where they've got
13 something they call the revenue-to-cost ratio, they do
14 the revenues and costs for the distribution function
15 and exclude the pass-throughs. So others have done it
16 in the same way as FEI's margin to cost ratio.
17 The advantage of that, as pointed out in
18 the report, is one, the margin -- the pass-throughs
19 vary across different classes. So using an MC ratio
20 for all the classes as the primary measure, in a
21 sense, makes more sense when you're comparing classes.
22 It also means that by definition your pass-
23 throughs should be essentially passed through exactly.
24 So you're removing something that's a straight flow-
25 through and getting down to the actual sources of
26 variance. But again, I'd emphasize, as we say in the

1 report, when you're looking just at margin, you're
2 going to have a greater variance from 100 percent, and
3 with an M:C ratio there's a stronger rationale for
4 maintaining the 90 to 110, because it's something
5 which inherently has more uncertainty on -- in a
6 percentage basis.
7 The final slide for today just points out a
8 couple of examples of -- we've had some -- you know,
9 there are typos buried through the report.
10 **Proceeding Time 10:41 a.m. T22**
11 When we've gone through there could be 20 things where
12 there's S's that shouldn't be there and things like
13 that. I don't think there's anything in the report,
14 any of those typos that would cause confusion. I hope
15 not. But we did not -- these ones are sort of
16 potentially sources of confusion. They were sort of
17 Aha's when we read them.
18 And that's it, over to the next stage of
19 the process.
20 THE CHAIRPERSON: Okay. We will start with interveners
21 asking questions of both FEI and Elenchus.
22 MR. BYSTROM: Madam Chair? May I just mark as an Exhibit
23 FEI's presentation materials? I believe it is
24 supposed to be Exhibit B-19.
25 (FEI PRESENTATION MATERIALS MARKED AS EXHIBIT B-19)
26 THE CHAIRPERSON: Okay.

1 MR. MILLER: And, Madam Chair, if I could mark the
2 Elenchus presentation as Exhibit A2-18.
3 (ELENCHUS PRESENTATION MATERIALS MARKED AS EXHIBIT
4 A2-18)
5 THE CHAIRPERSON: Great, thanks.
6 MR. BURSEY: Thank you, Madam Chair. Mr. Bemister handed
7 me a microphone, so I'm guess I'm on deck. Would you
8 like me to go up to the podium or is just in place
9 fine?
10 THE CHAIRPERSON: Wherever you're comfortable. I don't
11 know how you usually do this part.
12 MR. BURSEY: And I promise no karaoke. I'm pretty good
13 though. Good morning. I have just a few questions
14 and they relate to a response that Fortis gave to the
15 Commission IR.
16 So this is the IR filed on August 31st,
17 Exhibit B-15. And I'm looking at page 20. And this
18 is IR 7.2.
19 And while you're flipping that up, the IR
20 asks Fortis to recalculate the table 12.2 using a
21 range of reasonableness of 95-105 percent, which
22 Fortis did. But then on page 20 there's a couple of
23 sentences there that caught my attention. Rebalancing
24 -- sorry, halfway through the paragraph at the top it
25 says:
26 "Rebalancing the charges under rate schedule

1 22A would be inconsistent with continuing to
2 grandfather the terms and conditions of
3 service under this rate schedule. Since
4 RS22 is available for all large industrial
5 customers, grandfathered RS 22A and RS 22B
6 customers may elect this rate schedule as an
7 alternative. Consequently, FEI has not
8 rebalanced RS 22A to 105 percent for this
9 response."
10 Do you see that?
11 MR. GOSSELIN: Yes.
12 MR. BURSEY: Yes. So that essentially means you left the
13 Rate Schedule 22A where it was?
14 MR. GOSSELIN: Correct.
15 MR. BURSEY: And when you say that the terms and
16 conditions of this rate schedule are grandfathered,
17 are the rates also grandfathered?
18 MR. GOSSELIN: As we had proposed in the application, we
19 proposed to grandfather the terms and conditions, and
20 basically the status of 22A and B.
21 MR. BURSEY: The question is: Are the rates
22 grandfathered? They varied over time.
23 MR. GOSSELIN: Yes.
24 MR. BURSEY: I think the answer is, no, they're not
25 grandfathered. Is that correct?
26 MR. GOSSELIN: The rates move with the revenue

1 requirement over time as other rates do.
2 MR. BURSEY: Correct.
3 MR. GOSSELIN: Yeah.
4 MR. BURSEY: Mr. Perttula, you've got some history on
5 this one. Is that correct?
6 MR. PERTTULA: I would've just said the same thing that
7 Rick just said.
8 MR. BURSEY: So when you calculate a revenue-to-cost
9 ratio that shows that this rate is at 113 percent,
10 that's telling you according to your analysis that
11 this rate class is paying more than the cost of
12 serving this rate class? Is that correct?
13 **Proceeding Time 10:46 a.m. T23**
14 MR. GOSSELIN: That's telling me that the revenue to cost
15 ratio is outside the range of reasonableness.
16 MR. BURSEY: Right. And it's outside the 90 to 110 range
17 of reasonableness and even more outside the 95 to 105
18 range of reasonableness, correct?
19 MR. GOSSELIN: It's outside the 90 to 110, yes.
20 MR. BURSEY: And even more so. So is there any
21 Commission directive to say, "Keep the rate where it
22 is"? I'm trying to decide, is this a Commission
23 directive or is this an FEI policy that you've landed
24 on?
25 MR. PERTTULA: Well, first of all, the rate is changing
26 with general revenue, increased revenue requirement

1 increases. So, but this is a determination that we
2 made, and that we thought was appropriate in the
3 context of rate schedule 22A and 22B being closed and
4 grandfathered rate schedules with fairly -- with
5 favourable terms and conditions and rates.
6 MR. BURSEY: But we've agreed earlier the terms and
7 conditions are grandfathered, but not the rates. Is
8 that right?
9 MR. PERTTULA: Right. Subject to the level of the rates,
10 other than being subject to the revenue requirement
11 increases, is -- they are lower rates than the rate
12 schedule 22.
13 MR. BURSEY: So, but your cost of service analysis is
14 telling me that this rate schedule for 22A, look at
15 that one, is paying more than the cost of serving that
16 customer class. That's being at 113 percent, R:C
17 ratio. Is that correct?
18 MR. PERTTULA: That's what the analysis says. I think
19 it's a fairly straightforward question.
20 MR. BURSEY: Yeah. But I think discussion beyond that is
21 more about -- of a rate design related question that
22 would properly fall into subsequent parts of this
23 process.
24 MR. BURSEY: That's fair. But the analysis of the
25 contribution that this customer class is making to the
26 cost of serving this customer class — I'm speaking of

1 rate schedule 22A — that 113 revenue cost ratio says,
2 according to your analysis, that this customer class
3 group is paying more than the cost of serving it. Is
4 that correct?
5 MR. GOSSELIN: Can you -- I'm trying to find the 113
6 percent. What --
7 MR. BURSEY: If you look on page 19.
8 MR. GOSSELIN: Oh, okay. Sorry, thank you. Ah.
9 MR. BURSEY: Rate schedule 22A. So it's out of the range
10 of reasonableness.
11 MR. GOSSELIN: It's outside of the range of
12 reasonableness, yes.
13 MR. BURSEY: And it's on the high side. So it's paying
14 more than its fair share. Is that correct?
15 MR. GOSSELIN: You can construe that, yes.
16 MR. BURSEY: All right. I think that's a fair
17 conclusion.
18 So when the Commission asked you to
19 recalculate the rate schedules, it didn't say,
20 "Exclude rate 22A."
21 MR. GOSSELIN: No, the question did not say that. We
22 stuck with the proposal that was in the application.
23 We stuck with the treatment that was in the
24 application where we proposed to hold 22A and B
25 grandfathered and not rebalance them with the
26 application.

1 MR. BURSEY: So you decided to modify the Commission's
2 question and rebalance all the other ones except for
3 that rate schedule, is that correct?
4 MR. GOSSELIN: I don't agree with that -- the way of --
5 the way you've identified that. I think we were
6 forward with the way that we did answer the question,
7 and that we -- they asked us to 95/105, and I assumed,
8 or made the decision, that all else equal. And we
9 didn't rebalance them, we didn't propose to rebalance
10 them in the original application, so I stuck with that
11 method in answering the IR.
12 MR. BYSTROM: I want to just add -- sorry to interrupt,
13 Mr. Bursey. But --
14 Sorry. My name is Chris Bystrom. I just
15 want to interject because I thought the question was a
16 little unfair. BCUC IR 7.2 there asks for an updated
17 version of the table. And that's what FEI has done.
18 MR. BURSEY: Right. To move it to 95 to 105. I didn't
19 see any exclusion for rate schedule 22.
20 MR. BYSTROM: So in the original table, they're also --
21 the rate schedule 22A and B were not rebalanced.
22 MR. BURSEY: Right. But that's an issue we'll get to.
23 MR. BYSTROM: You were characterizing FEI as modifying
24 the question. So, that's just what I'm addressing.
25 MR. BURSEY: All right. Well, let's go back to the -- in
26 the application, there is no directive from the

1 Commission to keep rate 22A outside the range of
2 reasonableness, or not -- to treat it differently and
3 not rebalance it to within the range of
4 reasonableness. There is no directive from the
5 Commission to say that.
6 MR. GOSSELIN: I'm not aware of any direction.
7 MR. BURSEY: Okay. Nor am I. So that's an FEI decision.
8 MR. GOSSELIN: Correct.
9 **Proceeding Time 10:51 a.m. T24**
10 MR. BURSEY: During the workshop the revenue to cost
11 ratio for rate 22A was at 180 percent, do you recall
12 that?
13 MR. GOSSELIN: Yes.
14 MR. BURSEY: And that was based on some error of
15 calculation?
16 MR. GOSSELIN: That's correct.
17 MR. BURSEY: And during the workshop you proprosed to
18 rebalance the rate downwards, correct?
19 MR. GOSSELIN: I believe during the workshop -- I don’t
20 recall that, sorry.
21 MR. BURSEY: There was a substantial reduction proposed
22 for the art rate, 22A, was about 36 percent. My
23 customer group was quite excited about it, I can tell
24 you. You don’t recall it. Mr. Perttula, do you
25 recall it?
26 MR. PERTTULA: No, I don’t.

1 MR. BURSEY: Okay, maybe we can --
2 MR. BYSTROM: Madam Chair, can I just interject here for
3 a moment in terms of the relevance of this line of
4 questioning at this point to this SRP.
5 I agree that there is some relevance in
6 terms of the cost of service allocation, but the
7 actual proposals to rebalance are a rate design issue
8 in my view, and it seems like we are going down that
9 road at this point. So, in my view, Mr. Bursey should
10 move on.
11 MR. BURSEY: Madam Chair, the issue for this proceeding
12 is what is the range of reasonableness, and where I'm
13 going with this is my customer group wants to be
14 within that range of reasonableness. So yes, rate
15 rebalancing we can talk about later, just so long as
16 it is clear on the record if we want to come back to
17 it at that part of the proceeding then that is fine.
18 But if there is a decision made that FEI is to move to
19 105 to 95 range of reasonableness, then I don’t want
20 any implicit or explicit exclusion of Rate 22A from
21 the application of that range.
22 MR. BYSTROM: I think I could just add, and the witnesses
23 could expand on this if that would be helpful, that
24 the range of reasonableness, as I understand it, is a
25 guide for the Commission. So, I think that you can
26 again maybe -- or witnesses can explain it further,

1 but it's a guide, so the Commission isn't compelled to
2 rebalance to the range. It is just a guide for the
3 Commission to consider in the rate design process.
4 So, I don’t believe that a conclusion on the range of
5 reasonableness on this SRP will bind the Commission to
6 rebalancing Mr. Bursey's clients.
7 MR. BURSEY: My questions arise from the response that
8 FEI gave to this IR, which is a technical question for
9 this proceeding. I think it is fair to pursue it.
10 I've only got a couple more left. I wante dto know
11 why was it appropriate to rebalance from 180 percent
12 down during the workshop, and all of a sudden during
13 the application FEI has made the decision no, we'll
14 leave the rate where it is.
15 MR. BYSTROM: I'm hesitant to keep persisting here, but -
16 -
17 MR. BURSEY: If you wish to give the answer, you can, Mr.
18 Bystrom.
19 THE CHAIRPERSON: If you just give us a moment, thanks.
20 Mr. Bursey, can you finish up quickly?
21 MR. BURSEY: That question is why the difference between
22 the workshop treatment -- maybe I can help you. I
23 would assume that a revenue-cost ratio of 180 percent
24 would suggest that the rate paid by rate schedule 22A
25 seemed extraordinarily high and needed to be
26 rebalanced, so that is why in the workshop materials

there was a decision made to try and rebalance that rate lower, is that correct?

MR. GOSSELIN: I think that's a fair way to describe it.

MR. BURSEY: So it is a question of a degree, to how far outside the range of reasonableness you'd make that decision? So, 180 percent FEI decided we have to do something; 113 percent, we don’t need to do anything?

MR. GOSSELIN: I think that's fair.

MR. BURSEY: And I take it also by the last sentence in that paragraph that I read that there is a motivation to try to drive these customers to rate schedule 22?

MR. GOSSELIN: I would disagree with that, the way you described that.

MR. BURSEY: So, you say that that is an alternative. If you are unhappy with the rate under 22A, you can always move to rate schedule 22.

Proceeding Time 10:56 a.m. T25

MR. GOSSELIN: Yes, rate schedule 22A and B are closed if the similar rate would be the proposed rate schedule 22 whereas there's a firm component and an interruptible component, yes. The rate schedule 22 as proposed.

MR. BURSEY: So it's a different set of terms and conditions?

MR. GOSSELIN: I'm not entirely familiar with all the terms and conditions of those two rate schedules but I

1 suspect they are somewhat different.
2 MR. BURSEY: A slightly different question, one of the
3 key features of rate schedule 22A from FEI's
4 perspective is FEI can call on peaking capacity. Or
5 you can call on the capacity that the transportation
6 customers have reserved for a number of days. Do you
7 --
8 MR. BYSTROM: Madam Chair, we're now firmly in the realm
9 of rate design, we're talking about terms and
10 conditions of service. These are not matters that the
11 Commission will have to determine in this SRP. We
12 have a lot of questions yet to be heard today. I
13 think we should draw a line and these questions can be
14 asked in future parts of the proceeding.
15 MR. BURSEY: Madam Chair, the question I'm setting up is
16 to what extent under the COSA study was any value
17 given to peaking capacity that these customers
18 provide. And that is a fair question for the COSA
19 study. I'm sure my friend Mr. Bystrom would agree.
20 THE CHAIRPERSON: I agree that's in scope.
21 MR. BURSEY: So, Mr. Gosselin, can you summarize the
22 peaking.
23 MR. GOSSELIN: I understand that the peaking resource
24 available to FEI from 22As are 5 one-half days. Ed,
25 can you?
26 MR. MOORE: Yes, it's five one-half days. I think

1 Cominco and Trail, there is a special arrangement for
2 it. It works a little bit different. Is that right,
3 Kevin?
4 MR. HODGINS: Instead of five half days, they spread it
5 out for ten days.
6 MR. MOORE: Okay, so ten full days for Cominco. This is a
7 separate arrangement. But five half days, yes.
8 ME. GOSSELIN: So FEI can draw five half days as a
9 peaking resource.
10 MR. BURSEY: And can you tell me under the COSA study was
11 any value given to that benefit to the system without
12 it eating the --
13 MR. GOSSELIN: Effective in the COSA study, no. And that
14 changed --
15 MR. BURSEY: Sorry, I didn't hear that.
16 MR. GOSSELIN: In the COSA study that effectively is not
17 recognized. However, the way we have done it is
18 consistent with the Commission decision on the Inland
19 87 rate design.
20 MR. BURSEY: 1987 rate design.
21 MR. GOSSELIN: 1987 rate design.
22 MR. BURSEY: Now you're challenging even my memory. So,
23 if value was given to that peaking resource that this
24 customer class provides, would that show up in the
25 revenue-to-cost ratio as a revenue or benefit or value
26 given to the FEI system?

1 Ms. Tabone, feel free to answer.
2 MR. GOSSELIN: By valuing rather the peaking resource for
3 those customers, it would most likely end up as a non-
4 cost based customer when you look at their revenue-to-
5 cost ratio similar to the rate schedule 4, the 7/27,
6 when you look at the revenue-to-cost ratios. Because
7 you're basically taking something that's non-cost
8 based and applying it to their revenue to cost ratios
9 within the COSA. So, you're divorcing the allocation
10 cost and revenues from the -- sorry, yeah, you're just
11 applying something that is not cost based into the
12 COSA.
13 MR. BURSEY: So there's no cost to FEI but there is
14 certainly a cost to the customers if you take a half
15 day of their capacity and their gas, isn't there?
16 MS. TABONE: The issue is when you have
17 interruptability --
18 MR. BURSEY: Sorry, I would like you to answer that
19 question first, there's cost to the customer.
20 MR. GOSSELIN: Sorry.
21 MR. BURSEY: There's cost to the customer if you take a
22 half day of the gas and capacity.
23 MR. GOSSELIN: If it's taken.
24 MR. BURSEY: So, the answer to that is yes, if it's
25 taken. So that five half days has a cost to the
26 customer if it's taken, is that correct, Mr. Gosselin?

1 MR. GOSSELIN: I suppose that would depend on the
2 circumstance of the customer.
3 MR. BURSEY: Mr. Gosselin, if it's a peak day and you
4 require the gas, then those customers are requiring
5 gas, they have to have backup supplies to make sure
6 that they can supply their mills. Is that a
7 reasonable assumption?
8 MR. GOSSELIN: I think that's reasonable.
9 MS. TABONE: Okay, so the issue with any type of
10 interruptible load is that if you were to say it's all
11 firm, they get a full allocation of the cost. And for
12 interruptible load that doesn't quite make sense.
13 **Proceeding Time 11:02 a.m. T26**
14 MS. TABONE: If you say that there's zero allocation to
15 them because they're interruptible, and they're never
16 putting load on the system, that isn't quite fair
17 either, because then they're not paying any of the
18 costs, even though they do use it on some days. So,
19 in the case where there is five interruptible days,
20 you probably, if you don’t assign them firm, the
21 alternative to provide them zero demand for that
22 portion of interruptability is not going to be
23 probably a fair allocation. And so FEI has looked at
24 customers that are interruptible for the most part,
25 and taken them outside of the cost of service study.
26 And so that is why rate schedule 4 and 7/27 aren't

1 looked at in the same manner as rates 1 and 2, because
2 there is a value of service there that the COSA just
3 doesn't really handle very well.
4 MR. BURSEY: But these are -- rate schedule 22A is a firm
5 customer, it is not considered an interruptible
6 customer.
7 MR. GOSSELIN: Yeah, there -- a portion, certainly a
8 large portion of their demand is firm.
9 MR. BURSEY: That's right. Thank you, those are all my
10 questions. I appreciate the indulgence.
11 THE CHAIRPERSON: Thank you.
12 MR. MARTISKAINEN: Jouni Martiskainen with Catalyst
13 Paper. I have a few questions, so I'll try to go
14 through them as quickly as possible.
15 On the revenue-to-cost ratio with rate
16 schedule 22 and the proposed rate schedule 22, there
17 is a huge change from 1,425 percent revenue-to-cost,
18 to 100 percent, which is quite dramatic. And part of
19 that comes from combining some smaller industrial
20 customers that are mainly IT with the Vancouver Island
21 Gas Joint Venture, which Catalyst is part of. And BC
22 Hydro which have a large, firm component.
23 In that, I guess revenue to cost design or
24 assessment, was any other alternative looked at? Say
25 for example, rate schedule 22(vi) to take in large
26 industrial customers on the Sunshine Coast and

1 Vancouver Island that would be similar to 22A and 22B
2 with geography and special conditions. It seems like
3 a bit of a strange marriage where you have pulp mills,
4 large customers combining with, you know, greenhouses,
5 health care, education, food and beverage facilities.
6 So, was there another thought from -- a different
7 approach to go from 1,400 percent to 100 percent?
8 MR. GOSSELIN: Well, categorizing it as going from 1,400
9 percent to 100 percent is not really reasonable. When
10 you look at the 1,400 percent, they're fully
11 interruptible with a little bit of firm demand in
12 there. So, and it was a rate that was set. The rates
13 were rather set on a value of service, not a cost
14 basis. At 100 percent, we're looking at the package
15 of RS22 plus the JV, plus Hydro, and any other RS22
16 that could come about in the service area, and
17 assessing what would that rate look like, and that
18 would be a cost-based rate.
19 So, following the principles of
20 amalgamation and common rates, we were
21 proposing or we were looking at the system
22 as a whole, and looking at the type of
23 customers, the large industrial customers
24 that could come on in the system. And
25 those include the RS22s in the lower
26 mainland, and also the JV and the Hydro.

1 Where they are is different, but again,
2 from amalgamation and postage stamp rates,
3 we're looking at the type of customers and
4 I would disagree that they -- they're not
5 entirely different just because they're
6 over on the Island and they have a joint
7 venture idea. But they're large customers
8 that use a fairly large sum of gas. And
9 so, from a proposal perspective, we looked
10 at basically what would that group look
11 like as a single group within the utility.
12 **Proceeding Time 11:06 a.m. T27**
13 MR. MARTISKAINEN: Okay. Just from, I guess, from the
14 numbers there, a joint venture as a whole is over
15 7,000 TJs per year. BC Hydro, in the numbers, was
16 over 16,000 TJs per year. RS-22 average was around
17 500 TJs per year. So the numbers just look different.
18 And again, if you look at other industrial
19 rate schedules, RS-22A and B, they average
20 approximately 1,000 TJs per year. So the numbers do
21 look different to us, and the type of customer does
22 look different.
23 Second question, on workshop number 2,
24 March 9th, slides 25 through 26, there is sort of a
25 description of distribution, plant -- or distribution
26 rate base and how it's allocated, for approximately $2

1 billion in the rate base. In those slides, there is
2 RS-22 proposed shown, which is about 60 TJs per day is
3 peak day. And there's allocations for distribution
4 mains, service and meters, breaking that up into
5 demand and customer allocations. What's missing from
6 that $2 billion is any allocation to RS-22A or RS-22B.
7 So in the total rate base of 4.5 billion in the two
8 point -- I think 175 billion in the distribution
9 system, there is zero dollars allocated. And can you
10 just sort of explain why industrial customers, mainly
11 on transmission systems in the Interior, would have
12 zero dollars of that $2.2 billion rate base excluded?
13 MR. GOSSELIN: Yes. When developing the COSA and making
14 the decision internally to grandfather 22As and Bs,
15 terms and conditions, we continued to allocate costs
16 to those two rate groups similarly as we have done in
17 the past. Because of that, they're closed rate
18 schedules and such. So that is the reason why they
19 weren't allocated distribution-related costs. And the
20 reason why when we group up all the other rate
21 schedule 22s, including JV and BC Hydro and any other
22 rate schedule 22s that may join, we wanted to look at
23 them as a whole, on an amalgamated view, regardless of
24 where they might turn up in the system. So --
25 MR. MARTISKAINEN: So if you look at the -- I guess,
26 1993, going forward with 22A and 22B, at that time and

now, FEI's position is that it's justifiable to not allocate distribution costs to high pressure transmission system customers.

MR. GOSSELIN: That is the nature of the application and the fact that we grandfathered 22A and B.

MR. MARTISKAINEN: Okay. And so in the COSA, when you look at the $2.275 billion in distribution plant, or the distribution rate base, there's zero dollars going to RS-22A and RS-22B. Is that correct?

MR. GOSSELIN: I believe that's fairly --

MR. MARTISKAINEN: Okay.

MR. GOSSELIN: I'd have to take a look, but I suspect you're close to being right.

MR. MARTISKAINEN: Okay. So in terms of the RS-22A and 22B, just to be clear, if you take a look, the pie of the 4.5 billion items that are in the transmission rate base will get allocated there, but nothing else. Because they are a transmission system customer, they don't take gas from distribution pipes.

MR. GOSSELIN: They are allocated transmission related costs, yes.

MR. MARTISKAINEN: Okay.

MS. TABONE: But they would get the metering costs, that would be really a component in the distribution system.

Proceeding Time 11:11 a.m. T28

1 MR. MARTISKAINEN: Okay. So if you take a look at the
2 revenue-to-cost ratio that we just discussed, of 113
3 percent, or the joint venture revenue-to-cost ratio of
4 122 percent, which was presented earlier in response
5 to a BCUC question, the revenue side is quite simple,
6 it's dollars. Is the cost allocation in that revenue
7 to cost ratio for the joint venture, and 22A and 22B,
8 is it fair to say that the methodology used to
9 generate that cost in the R:C ratio is different
10 although the revenue-to-cost ratios both start with a
11 one? In one case there's no distribution costs
12 associated with RS 22A and 22B, and we just said that
13 that makes sense.
14 MR. GOSSELIN: Yes, that's correct.
15 MR. JONI: And then in the proposed RS 22, which would
16 include the joint venture, and BC Hydro's large firm
17 customers, and also Creative Energy and others, there
18 seems to be, again, distribution plant or
19 distributions rate based costs, particularly the
20 demand, allocated to the proposed RS22. So would we
21 say that that's a different allocation of distribution
22 rate base for large industrial customers in the
23 proposed RS22?
24 MR. GOSSELIN: Sorry, could you ask that again?
25 MR. MARTISKAINEN: So in 22A and 22B we're saying that
26 the distribution system cost zero dollars is going to

be allocated. If you take a look at RS22 proposed, which has joint venture Hydro, Creative Energy, in those slides from the workshop there are costs allocated from distribution as demand going straight towards these large industrial customers.

So in one case the 50 percent of the pie does not go towards 22A and 22B transmission system customers. And in the other case there is an allocation from that 50 percent of the pie towards BC Hydro joint venture and other folks that are on the Sunshine Coast-Vancouver Island transmission system in the proposed RS22. That's my reading.

MR. GOSSELIN: The proposed RS22 includes Lower Main- -- any RS22 or anyone that's a large industrial in the system except the 22As and Bs, so those could include 22s that are inland, Lower Mainland, and Vancouver Island. So as a group, yes, they are allocated distribution related costs.

MR. MARTISKAINEN: Okay.

MR. GOSSELIN: And 22As and Bs, I can't say it's zero, but it's certainly not --

MR. MARTISKAINEN: Okay. And then just --

MR. GOSSELIN: -- much of them.

MR. MARTISKAINEN: Yeah. Just in terms of numbers, if you look at, again, Workshop 2, March 9th, 2017, slide 32, and if you also look at slide 38, which is the

1 summary of delivery cost allocation, you can kind of
2 look at the demand cost to peak day or firm ratio.
3 And, again, for the proposed RS22 firm, the number
4 comes out at 0.316 million dollars TJ per day. That's
5 the ratio. And 22A and 22B where the cost allocation
6 methodology is different, instead of .317 it's .168
7 and .174. So just from a -- I know the revenue-to-
8 cost ratio table looks reasonable. When we look at
9 the actual volumetric cost for that firm it looks
10 significantly different. So that's just sort of a
11 comment we'd like to put forth at this point in time.
12 It's up to 88 percent higher on a volumetric basis
13 when you include the demand from the distribution rate
14 base into the proposed RS22.
15 I guess there was some other reference to
16 the history in rate schedules RS 22A and 22B. And
17 also if you look at the, I guess the history for
18 TGVI/FEVI Centra Gas on Vancouver Island and look at
19 the previous COSAs that they've done, they would break
20 it up into high pressure transmission system, HPTS,
21 and also distribution. And in those when you looked
22 at the Vancouver Island gas joint venue and BC Hydro,
23 the distribution cost allocation was always a total of
24 zero dollars.
25 So, again, when you look at taking a zero-
26 dollar distribution allocation historically and you

take the same customers, and now there's -- 70 percent of the distribution system is going to be called demand and thrown into the cost, into proposed RS22, it seems like a significant shift in methodology for treatment on folks that use the transmission system on Vancouver Island. Would you agree or disagree with that statement?

Proceeding Time 11:15 a.m. T29

MR. GOSSELIN: Well, the proposal follows on from the amalgamation and common rates application where we're treating our system as a whole regardless of your location. So, the next RS22 customer could be in the Lower Mainland, which would basically track distribution at any cost. The next RS22 customer could be down at the end of Victoria, which would also be the end of a distribution system. So, we're trying to develop a rate that would be logical and reasonable for any large industrial customer regardless of where they're located in the system.

MR. MARTISKAINEN: Okay, but the RS22 proposed, you just mentioned if you're in Victoria as a distribution customer on the distribution system, that wouldn't be equivalent to someone who's on the transmission, would it be necessarily? The other receiving gas through the distribution system while others are not.

MR. GOSSELIN: You have to understand that every customer

1 costs differently to serve. Every customer. The one
2 -- your neighbour next door if they're further away
3 from the upstream transmission system they cost a
4 different amount to serve. At what point do you stop
5 parsing customers down, down and down to create a
6 million different rate schedules, or do you stop at a
7 place that's reasonable where the characteristics of
8 the customers are similar. And try to develop a rate
9 that's -- yeah, try to develop schedule that makes
10 sense and is usable regardless of where the customer
11 locates in the system.
12 MR. MARTISKAINEN: For the proposed RS22 there's
13 transmission costs, obviously, and I think in the 2016
14 COSA there's a note that the Southern Crossing
15 Pipeline, SCP, costs are included as a postage stamp
16 cost. So, that goes into the rate base of
17 transmission and then, based on your peak day, you
18 could get a certain slice of that pie. Is that
19 correct?
20 MR. GOSSELIN: Again that's correct. The SCP is a
21 transmission pipeline used by the utility, depending
22 where you are in the utility whether you'll actually
23 see a molecule run through that or not. But, again,
24 back to how far down the rabbit hole do we go? We
25 need to keep a high enough level so that the rate
26 design can be applicable to wherever you are, wherever

1 that industrial customer happens to locate on this.
2 MR. MARTISKAINEN: Sure, and the revenue to cost ratio
3 for RS22B, is the southern cross pipeline capital
4 costs included in RS22B cost allocation or is it
5 excluded? RS22B, I believe it's located directly next
6 to the southern crossing pipeline.
7 MR. GOSSELIN: No, I'm just trying to recall. I'm not --
8 I don't recall.
9 MR. MARTISKAINEN: Okay, if someone can clarify whether
10 or not SCP transmission infrastructure is allocated to
11 RS22B or not, that would help. And if is not, the
12 question we have is why would they not be allocated
13 that transmission cost? So, let's say for example
14 you're a pulp mill in the interior right next to SCP,
15 and then there's pulp mills on Vancouver Island that
16 are picking up SCP costs. That would be sort of a
17 glaring discrepancy that we would have concern with.
18 MR. MOORE: Just a clarifying note with respect to the
19 transmission. It doesn't matter where the
20 transmission pipe is located, its costs are included
21 in the COSA. And the way it is treated for cost
22 allocation purposes, it goes to all customers based on
23 their contribution on the peak demand.
24 MR. MARTISKAINEN: Okay, the question was, I think in
25 reference to the southern crossing pipeline there was
26 a direct mention that rate 22B was exempt from SCP

1 costs.
2 MR. MOORE: In the 2000 rate design and 2001 rate design,
3 that is correct.
4 MR. MARTISKAINEN: Okay.
5 MR. MOORE: But in how Southern Crossing is used today,
6 more currently, it's more appropriate to treat that as
7 just transmission cost and allocate it to all
8 customers.
9 **Proceeding Time 11:20 a.m. T30**
10 MR. MARTISKAINEN: Okay, so someone can confirm that in
11 the revenue-to-cost ratio that was displayed in the
12 table it includes ICP costs?
13 MR. GOSSELIN: I can confirm that, yes.
14 MR. MARTISKAINEN: Okay. The other general question I
15 guess is that there is some good explanation about the
16 bypass revenue, and how it comes back as a credit to
17 all the other customers. And then the other one that
18 is a little bit less clear or less consistent is the
19 IT revenue.
20 So, for example, in RS22 currently, when
21 you look at the revenues and the costs in the COSA, it
22 shows up as IT revenue. Similar I think for some of
23 the 22A and 22B. When it comes to the Vancouver
24 Island Gas Joint Venture, the IT revenue, the IT
25 volume is consistently absent from all the tables and
26 data presented. I think when the Utilities Commission

1 specifically asked the question "total revenue", then
2 it was brought into play.
3 So, in the 2016 initial COSA or 2012 COSA,
4 can you explain where in the COSA, or where in the
5 benefit to other customers, the Joint Venture IT
6 revenue is allocated in the financial schedules?
7 MR. GOSSELIN: In the 2016 COSA, the Joint Venture IT
8 revenue is included as a credit to the cost of
9 service, and allocated across all rate schedules based
10 on margin.
11 MR. MARTISKAINEN: And 2012 COSA?
12 MR. GOSSELIN: I believe all of the JV's revenues, ITN,
13 firm, were brought as credits to the cost of service
14 and allocated across.
15 MR. MARTISKAINEN: Okay. The other general question
16 again around the existing RS22, the revenue to cost
17 ratio was shown at 1,425 percent. The bulk of the
18 volume was interruptible, a small amount at 2,000 GJs
19 per day was firm. And if you could take a look at the
20 numbers, it is 95 percent interruptible, 5 percent
21 firm. There is a allocated cost of firm delivery from
22 the COSA model that is quoted at 97.2 cents per GJ.
23 So, if you take those numbers and you try to have a
24 look at, you know what does that mean, it means that
25 the IT cost of service is a negative value, which
26 doesn’t make sense. So, there is no variable cost,

there is no O&M for the IT. So when you look at those numbers on — it's the RDA 2016 Appendix C, Fully Distributed COSA Study, Schedule 7. It's page 971 of 1782 — the math doesn't make any sense, just from a simple standpoint. Is it possible to take that schedule 7 and break up the current RS22 for a firm volume, firm cost of service, IT volume, IT cost of service? And we know that the combination R:C ratio is 1,425 percent, but is the firm approximately 1.1 and the IT is 3,000 percent? And then again, if it is 3,000 percent, would that be a reasonable IT rate to be set in a regulated utility?

MS. TABONE: I think what we tried to do, and maybe it wasn't recognized in some of the past, in 2012 fully, or some of the tables that were intially put out, was to recognize that interruptible loads cannot be measured in a cost of service study. And so, or the value of it, or the revenue to cost ratios do not make sense when you're talking about interruptible load. And so to split out the firm load and interruptible load and have a revenue to cost ratio for both, might make sense for the firm part, but it just doesn't make sense for the interruptible part. And that is where the value of service comes in. So, if you were to look at interruptible loads, and if no other customers on the system got credit for it, then it would

1 basically be giving it away for free, which, why would
2 Fortis do that?
3 **Proceeding Time 11:25 a.m. T31**
4 So the concept behind it, and the same
5 applies to a bypass customers, is that every customer
6 is better off as long as you get some revenue from it.
7 And so you have to look at the value of that revenue
8 and set a rate, whether it's a discounted rate over
9 firm, or whether it's a bypass rate that's calculated
10 based on the cost to somebody else of bypassing the
11 system, and set a rate outside of the cost-of-service
12 study.
13 And so once you set that rate, it's set on
14 a value of service, and to then apply those revenues
15 to allocate a cost in a COSA does not make sense,
16 particularly when you allocate zero cost to
17 interruptible service. If you were to maybe say that
18 interruptible should pay some share, but not a full
19 share of demand, that might make sense to do, and
20 discount the amount of load that they're allocated and
21 say, well, it's -- they get 25 percent allocation
22 instead of 100 percent allocation. That would make
23 sense. But that would require some judgment.
24 So rather than do that, FEI took all of the
25 interruptible revenues, used them as other revenues,
26 gave credit back to all of the customer classes,

1 including the classes that provided that interruptible
2 revenue.
3 MR. MARTISKAINEN: Okay. Next question is around the
4 bypass customer and the revenue-to-cost ratio in -- I
5 think it's document B-5-1, FEI submitting a response
6 to BCUC. It's the updated Table 6-19 on page 53.
7 On that, there is a revenue to cost ratio
8 for bypass customers that's reported at 14.6 percent,
9 I believe. And the revenue from bypass customers is
10 listed at $1.281 million. So again, if you use the
11 stated cost of 97.2 cents per GJ for firm, you don't
12 necessarily come up with the same 14 percent.
13 So, can someone verify what cost is used
14 for bypass customers? We know what their firm is, we
15 know what the revenue is. It doesn't appear to be
16 97.2 cents per GJ as the cost that's allocated in that
17 R:C ratio. I don't know if you have the number now,
18 but just as something we could look at.
19 MR. GOSSELIN: This question certainly would have been
20 better in the technical round.
21 MR. MARTISKAINEN: Yeah.
22 MR. GOSSELIN: I don't -- I can't -- it's too much.
23 MR. MARTISKAINEN: Okay, I'll leave it at that. I can
24 follow up with a written request.
25 MR. BYSTROM: Just to interject there a moment. I'm not
26 sure there is an opportunity to follow up with a

1 written request at this point.
2 THE CHAIRPERSON: I think that's right. The parties were
3 given an opportunity to ask technical questions in
4 advance.
5 MR. MARTISKAINEN: Okay, I'll leave it at that.
6 Another question again would be back to the
7 FEI response to BCUC IR number 1, pages 167 through
8 168. The Utilities Commission asked the question:
9 "Please state the percentage of the total
10 FEI 2016 forecast throughput represented by
11 large volume transportation customers
12 including RS22, 22A, 22B, VIGD, and BC
13 Hydro, IG."
14 And again, to a prudent person, that looks like asking
15 for throughput consumption, the total usage. So you
16 know, if you're looking at revenue-to-cost ratios, or
17 dollars per GJ on a volumetric basis, you need those
18 numbers.
19 It appears that, you know, there was a
20 mistaken omission again on the joint venture's
21 interruptible demand in the table. There is
22 interruptible demand shown in other rate schedules,
23 but not for the joint venture. So if you did include
24 the total demand, including the IT demand from the
25 joint venture, all the percentages in that table will
26 change.

1 So again, I don't know if that was just
2 standard practice in how the IT was handled, but it
3 does impact all the industrial consumptions or
4 throughput or volumetric basis answers.
5 MR. GOSSELIN: Is there a question there?
6 MR. MARTISKAINEN: A final question -- no. Sorry. Yeah.
7 The final question. Unit cost of service margin for
8 the proposed RS22. Again, if you look at the FEI RDA
9 2016, Appendix 12, Final COSA Financial Schedules,
10 schedule 7. It's the second-last page, 1781 of 1782.
11 The sales volume for Rate 22 firm, which is the RS22
12 proposed, is shown at 34,372 TJs in line 3.
13 And again, to the reader, when I'm looking
14 at the schedule 7 in the COSA, I think the assumption
15 is that we're looking at firm consumption and firm
16 costs, is that correct?
17 **Proceeding Time 11:30 a.m. T32**
18 MR. GOSSELIN: Yes, that is correct.
19 MR. MARTISKAINEN: Okay, so when you take a look at
20 34,347 TJs in line three, it appears that that sales
21 volume is not just the firm volume for proposed RS22
22 firm, it appears to contain a lot of IT volume so that
23 the volume number becomes larger than it should be,
24 but the revenues and the costs are still smaller,
25 because it is just the firm. So we have a firm
26 revenue, or a firm cost divided by firm plus IT

1 volume.
2 So, for example when you look at the demand
3 cost of service for rate 22 firm, it is stated at 56
4 and a half cents per GJ on line 12 of schedule 7,
5 which doesn't seem to make sense, because we're mixing
6 up IT and firm volume and costs in schedule 7, which
7 makes it very hard for the reader to actually
8 interpret that and make a comparison or make any
9 determination of whether that makes sense or not. So,
10 again, it seems like a typo at this point. Just be
11 cognizant of the fact that the numbers do not appear
12 to be firm costs and firm volume.
13 MR. GOSSELIN: I can't speak to that, whether you're
14 correct or not.
15 MR. MARTISKAINEN: Okay.
16 MR. GOSSELIN: Again, technical question that would have
17 been better in earlier round.
18 MR. MARTISKAINEN: Yeah. And that is my final question.
19 THE CHAIRPERSON: Okay, thank you.
20 MR. WEAFER: Chris Weafer from the Commerical Energy
21 Consumers Association. Again, I apologize for the
22 quick start earlier. Now is the time for questions.
23 I only have a couple of questions and CECs
24 ask a number of IRs, and I appreciate the responses
25 we've received from the company. Our position, as I
26 mentioned earlier, still revolves around the range of

1 reasonableness issue, and fairness to commercial
2 customers. And so I mentioned -- actually, Mr.
3 Gosselin, just to clarify a couple of comments this
4 morning. I think you indicated that the next COSA
5 study would not be for 10 years, and you may have
6 mispoke. When would you anticipate the next COSA
7 study being done?
8 MR. GOSSELIN: We said in the application I believe
9 somewhere in the evidence between 4 and 6 years.
10 MR. WEAFER: That's what I thought, okay. And the other
11 comment you made this morning, with respect to range
12 of reasonableness, and I just want to make sure it was
13 intended, I think you said it is impossible to target
14 unity at a reasonable cost. Was that your evidence
15 this morning?
16 MR. GOSSELIN: I said it was impossible to get perfect
17 cost allocations at a reasonable cost.
18 MR. WEAFER: Okay, fair enough. The first IR – I
19 mentioned it earlier on – that I'd like to go to, is
20 the CEC IR 1.19.3 in Exhibit B-11.
21 MS. TABONE: 19.3?
22 MR. GOSSELIN: Yeah 19.3.
23 MR. WEAFER: 1.19.3, and there was a follow up which we
24 don't need to go to in 1.69.1.
25 But I really just -- and I'm using 1.19.3
26 because it is more clear in terms of the -- and here

1 you provided the historical revenue-to-cost ratios for
2 each class over the last 20 years, and we did ask a
3 series of follow-up questions and we appreciate the
4 responses, but I just wanted to go to a high level on
5 the fairness topic, and the Bonbright principle of
6 fairness. And I recognize that fairness like beauty
7 is in the eye of the beholder. But, if we look down
8 over the last 23 years from 1993 and the residential
9 column, do see anywhere where the residential class
10 has hit unity, to pay this cost of service under
11 various studies over the years?
12 **Proceeding Time 11:34 a.m. T33**
13 MR. GOSSELIN: The residential class is within the range
14 of reasonableness on most of those years.
15 MR. WEAFER: No. The question was is there anywhere
16 where they've hit unity under your models over the
17 years under your cost of service studies?
18 MR. GOSSELIN: There's nowhere that the residential class
19 shows 100 percent on its revenue to cost ratio.
20 MR. WEAFER: Yeah. For 23 years it's been under unity.
21 And as I understand your response to the next cost-of-
22 service study it could be four to six years out and
23 the proposal is to maintain a range of 90-110 percent,
24 is that correct?
25 MR. GOSSELIN: We are proposing a 90-110 percent in this
26 application, yeah.

1 MR. WEAFER: So from the commercial customer class – and
2 let's just move over to the right on the graph through
3 small, large, and general firm customers – would you
4 agree with me that in the overwhelming majority of
5 instances, with respect to your revenue-to-cost ratio,
6 that they paid in excess of 100 percent of their cost
7 of service under you COSA study models?
8 MR. GOSSELIN: I think classifying them as paying more
9 than their fair share is probably an incorrect way to
10 put it. If they're within the range of
11 reasonableness, it's deemed that they're paying their
12 fair share of the allocated costs.
13 MR. WEAFER: Right. Sorry, let me rephrase -- they paid
14 more than 100 percent, more than unity under your COSA
15 studies and under your approaches over the last 23
16 years?
17 MR. GOSSELIN: They've paid their fair share of the cost
18 allocations.
19 MR. WEAFER: The expectation -- you'd agree with me that
20 there's a string consistency that the residential
21 customers are under unity and the commercial customers
22 are over unity in terms of the Fortis COSA studies
23 over the past 23 years and -- would you agree with
24 that?
25 MR. WEAFER: Well, you're implying that unity means
26 something in particular. Further to Elenchus's

1 report, and EES's report, and our responses to
2 countless IRs is the fact that someone falls within a
3 range of reasonableness, and the range being decided
4 upon by the Commission ultimately, there's an
5 assumption or -- they're deemed to be paying their
6 fair share costs. So the discussion around unity
7 doesn't really make too much sense to me given what
8 we've seen in evidence, and given what we've seen in
9 the past, and given what the Elenchus report has said
10 around people -- or, sorry, rate classes within a
11 range, within the range, rather.
12 MR. WEAFER: That's -- before we discuss unity in more
13 detail, would you agree with me that there's -- that
14 on the -- and we can differ as to whether unity is the
15 right target, but from the customer perception in
16 looking at the revenue-to-cost ratios, you would agree
17 with me that there's not just an annual impact, but
18 there's a cumulative impact?
19 If I'm a commercial customer and I'm
20 looking at this information, not only in each year am
21 I paying above unity, but over the course of 24 years
22 cumulatively I've been paying above unity and,
23 therefore, over time a fairly significant amount of
24 accumulated overpayment?
25 MR. GOSSELIN: Again, I disagree with you in your -- the
26 way you're framing the fact that someone is over 1 or

1 under 1. Again, as we've said in IR 14.1 and in some
2 others, that the range of reasonableness is there as a
3 guideline and within that range of reasonableness
4 you're considered to be paying your fair share of
5 cost.
6 MR. WEAFER: Okay. Let's discuss the range of
7 reasonableness and the unity concept. Do you have the
8 highlights of Elenchus's report which was filed this
9 morning in front of you?
10 MR. GOSSELIN: Sorry, their presentation?
11 MR. WEAFER: Yes.
12 MR. GOSSELIN: Yes.
13 MR. WEAFER: I mean, there's two places we can go. We
14 can go to that. It may be even better to go -- if you
15 have a copy of the Elenchus study, the rate design
16 report dated 23 June, 2017? That may be a better
17 document to go to if you have it handy.
18 MR. GOSSELIN: Is that Exhibit A2-2 or 2-10?
19 VOICE: A2-10
20 MR. GOSSELIN: A2-10, thank you.
21 MR. WEAFER: And if we go to page 33 and 34 of that
22 report. Do you have that?
23 MR. GOSSELIN: I do.
24 **Proceeding Time 11:40 a.m. T34**
25 MR. WEAFER: So when we look at it, you would agree with
26 me that these are the jurisdictional review of

1 Elenchus in terms of range of reasonableness on the
2 utilities that EEC looked at in their report. Are you
3 aware of that?
4 MR. GOSSELIN: Table 4?
5 MR. WEAFER: Yeah.
6 MR. GOSSELIN: Yes.
7 MR. WEAFER: Okay. And if we look at those six examples,
8 would you agree with me that three of the six target
9 close to unity, or unity?
10 MR. GOSSELIN: That is what it appears to say.
11 MR. WEAFER: Yeah. And the other three are 95 to 105
12 percent.
13 MR. GOSSELIN: Yes, as it's in the table.
14 MR. WEAFER: So we have no other example in terms of the
15 relevant utilities identified by Elenchus and reviewed
16 by EEC in their study. That is, at 90 to 110 percent.
17 MR. GOSSELIN: Not in this table.
18 MR. WEAFER: Right.
19 MR. GOSSELIN: However, I do recall one of Elenchus's IR
20 responses, and I believe it was to BCOAPO, where the
21 range is on a number of electric utilities in Ontario
22 are quite a bit -- they're a lot wider.
23 MR. WEAFER: We're talking about gas utilities here,
24 correct?
25 MR. GOSSELIN: But these ones are gas utilities.
26 MR. WEAFER: Right. They'd be the more relevant

1 comparables, I would assume you'd agree with that.
2 MR. GOSSELIN: Yes. Yeah.
3 MR. WEAFER: Thank you. And you'd agree with me, if we
4 look at the dates below, that these are all 2006 or
5 post-2006, in terms of the dates of these regulatory
6 decisions. Like Alta Gas.
7 MR. GOSSELIN: It's not clear for --
8 MR. WEAFER: But Alta Gas is 2014, Atco is 2006. Subject
9 to check, Union Gas, 2011; Enbridge, 2012; Centra,
10 2013, 2014, and Sask Energy is an application, 2016,
11 it hasn't been determined yet. You would agree, those
12 are the dates?
13 MR. GOSSELIN: Yeah.
14 MR. WEAFER: And those are more current than the numbers
15 that Fortis has put forward in terms of its
16 experiences with the Commission, would you agree?
17 MR. GOSSELIN: Those dates are more current than what the
18 response we have in 14-1.
19 MR. WEAFER: Thank you.
20 MR. GOSSELIN: However, they are not in B.C., and the
21 Commission's -- you know, the more relevant gas
22 utilities would be comparables in B.C., I suspect.
23 MR. WEAFER: You would say PNG is a more relevant
24 comparable to Centra Gas in Manitoba or other larger
25 gas utilities in this country?
26 MR. GOSSELIN: Well, they're in B.C. as we are, and it's

1 a different jurisdictions.
2 MR. TOKY: I just -- sorry. This is Atul Toky here.
3 Just would like to point out to the IR response, 7.1,
4 to BCUC. This is the FEI response to BCUC technical
5 IRs. If we can just go to that, the first line I just
6 would like to read that, is that:
7 "The appropriate range of reasonableness
8 depends on the particular circumstances and
9 the history of the public utility. And
10 therefore practices in various jurisdictions
11 may not be readily comparable."
12 So, what Richard and me have been talking
13 about this morning is that, yes, revenue-to-cost
14 ratios, and those are used as a guideline. And, you
15 know, the jurisdictions is -- basically the comparison
16 of those is basically used to see what's done in the
17 other jurisdictions. But really, what it comes to,
18 when it comes to the range or the reasonableness of
19 the revenue- to-cost ratios, we need to look at the
20 particular circumstances of a public utility, such as
21 FEI, and what has been done consistently over in the
22 past, and what that utility has used in the past.
23 MR. WEAFER: Right. And you're aware in British Columbia
24 there's at least two decisions from the Utilities
25 Commission which has indicated that if a rate class
26 goes outside of a range of reasonableness, they should

be set back to unity. And that would include FortisBC's electric utility, in the decision in that jurisdiction. Is that correct?

MR. TOKY: Gail, do you want to just touch base on that? Because --

MS. TABONE: That's my understanding of those two decisions. But I would --

MR. WEAFER: And just so we're on the same page, and I don't mean to interrupt, but it's the FortisBC electric decision. There's the BC Hydro electric decision in 2007 --

MS. TABONE: Right.

MR. WEAFER: -- where the Commission indicated unity is the right target if somebody falls out of the range, correct?

MS. TABONE: Correct. But I --

MR. WEAFER: Which would give -- would you agree that gives some credence to unity as a good target? In this jurisdiction.

MS. TABONE: Well, that was the direction for the electric utilities. But I would say that that was not something that we had seen before, in most jurisdictions. And in fact, Elenchus has said most people move to within the edge of the range of reasonableness. But that is what the Commission decided on those two particular instances.

1 **Proceeding Time 11:45 a.m. T35**
2 MR. WEAFER: Right. But didn't we just have a discussion
3 that three of the six examples from the Elenchus chose
4 unity as the target.
5 MS. TABONE: I don’t think they go to unity, they go
6 close to unity. And a lot of that depends on the
7 particular circumstances, which we don't know about.
8 We don't know how good their load data is. We don't
9 know how many different rate classes they have. In
10 some cases, they have three or four rate classes that
11 everybody falls into, and so -- like all of your
12 residential and general service might be in one rate
13 class but they just have all of these different tiers
14 of usage and they get the same rate. So, I'm not sure
15 how meaningful going to a hundred percent is when you
16 have all of your residential and general service
17 classes in one big rate class. So, there's a lot of
18 circumstances you'd have to look at at each one, which
19 we have not done.
20 MR. WEAFER: I appreciate you have not done that. So,
21 when we look at these examples we've got the
22 regulators in Ontario, Alberta, Manitoba and
23 Saskatchewan choosing a range between 95 and 105
24 percent on three occasions, and close to unity or
25 unity on the others. So, all of the other
26 jurisdictions from Ontario west used a narrower range

than Fortis is providing, is that correct?

MS. TABONE: Well, Union Gas and Enbridge would be the same regulator.

MR. WEAFER: Yes.

MR. TABONE: So, that's one province. And Sask Energy, my understanding is they're not regulated because they're a Crown Corporation. So they're a little bit different than the other ones.

MR. WEAFER: Right, but they --

MS. TABONE: Would be quite as -- wouldn't be fully tested as what would go on in Alberta or Ontario.

MR. WEAFER: But they identify in the evidence cited by Elenchus as 95 to 105 is the target.

Mr. Todd, I think you made a comment, and I don't have the IR response in front of me, but you didn't understand that load data in Fortis Gas to be materially different or less accurate than other gas utilities. Is that a correct summary to your response?

MR. TODD: The comment there was based on -- my understanding, is metering methodologies would be the same. Therefore, they do not have a measure of load at the peak in any of the jurisdictions, so in that way they're similar. And in addition, there is meter readings done on a cycle basis, so again meter reading, yes, this would be similar. So as far as I

1 know without doing a detailed comparison there'd be
2 similar metering therefore similar load data.
3 MR. WEAFER: Thank you. I'm just going to move on.
4 MR. PERTTULA: If I can just add something. There is a -
5 - and I will link this response to, in Exhibit A2-14
6 and this is a response to BCSEA IR#2, question 3.1
7 where Elenchus acknowledges that the specific
8 circumstances of the utility need to be considered,
9 and they also go on to say that they would emphasize
10 that the appropriate range of reasonableness depends
11 on the confidence that the regulator has of the
12 mathematical results of a cost of service study.
13 Relevant consideration includes the precision of the
14 accounting information relied on, the proportion of
15 costs that can directly allocated or have a strong
16 causal relationship based on cost drivers and the
17 extent to which judgement is relied on in the cost of
18 service study. And so, I think that supports,
19 strongly, the fact that we should be looking at the
20 specific circumstances and past history here in B.C.
21 rather than relying on what's happening in other
22 jurisdictions.
23 MR. BYSTROM: And Mr. Weafer, just before you move on I
24 just want -- a matter of clarity of the record, in a
25 couple of your questions you mentioned EEC, and I
26 think you meant EES Consulting.

1 MR. WEAFER: Thank you.
2 MR. BYSTROM: And your questions implied that this table
3 4 in the Elenchus report was viewed by EES. It was a
4 little unclear. But I just want to be clear that this
5 was a Elenchus's report not EES.
6 **Proceeding Time 11:49 a.m. T36**
7 MR. WEAFER: I will be perfectly clear. There was a
8 staff IR and they were asked -- sorry not a staff IR.
9 I think the instructions to Elenchus were to review
10 the range of reasonableness in regard to the utilities
11 that were studied by EES in the Fortis evidence.
12 Because Fortis, as I understand it, did not provide
13 that jurisdiction overview of revenue-to-cost ranges.
14 And so staff asked Elenchus to do that. So that's the
15 connection there. They're drawn from the sample that
16 EES used, and they are, I believe, in Elenchus's view,
17 the most relevant -- certainly in our view the most
18 relevant sample in terms of range of reasonableness.
19 I hope that's clear.
20 MR. BYSTROM: That's helpful.
21 MR. WEAFER: Thanks.
22 MR. BYSTROM: That clarified things.
23 MR. WEAFER: I have a question for Mr. Todd, and I don't
24 mean to embarrass or cause grief. But I have a couple
25 of conflicts related questions. I got an e-mail last
26 week that had Elenchus be one of the candidates to do

1 work for Fortis on its benchmarking study on PBR. So
2 can you just confirm -- you're not presently retained
3 by Fortis or any of its other companies at this time?
4 MR. TODD: Not that I'm aware of. Did we get retained by
5 something that I wasn't aware of?
6 MR. WEAFER: You're identified as one of the candidates,
7 and I don't know whether there's been discussions or
8 not, and I just want to make sure for the record, and
9 for your sake as well, that there are no conflicts.
10 You're not presently retained or in
11 negotiations with Fortis in regard to any work.
12 MR. TODD: No, we are not. In our work, we frequently
13 work with many different utilities. We frequently
14 work with many different regulators. We frequently
15 work with many different interveners. So, we have
16 lots of conflicts that cancel each other out.
17 MR. WEAFER: Well, that --
18 MR. TODD: No, in a sense. I mean, I'm being facetious.
19 Therefore, we do not have conflicts. We approach it
20 in a professional, neutral manner.
21 MR. WEAFER: That's fair. Let's be very clear. You are
22 not retained or are not doing any work for any Fortis-
23 related companies at this time.
24 MR. TODD: No. We are not.
25 MR. WEAFER: And you're not bidding on any such work at
26 this time.

1 MR. TODD: I am not necessarily aware of every bid that
2 takes place. Are you referring to an Alberta case? I
3 think we're involved with an associate company in
4 Alberta where we are -- potentially have a role for
5 some work which may relate to -- well, actually, would
6 not be for Fortis Energy, it's for the consumer
7 advocate in Alberta. So --
8 MR. WEAFER: Okay. If you --
9 MR. TODD: If that's what you're referring to, it's for
10 the consumer advocate involving another Fortis case.
11 MR. WEAFER: I'll be crystal-clear with you, and you may
12 not be aware of it, so I want to be fair to you. This
13 is specifically -- and in fairness to Fortis as well,
14 they're soliciting input from intervener groups as to
15 appropriate consultants to do a PBR benchmarking
16 study, which is directed by the Commission. Your
17 company's name is listed as one of the candidates, and
18 I just want to confirm that there is no negotiation,
19 there is no perception of conflict that we should
20 have, because you're not in any discussions with
21 Fortis in relation to that project.
22 MR. TODD: Sounds like somebody's put our name forward,
23 and I appreciate that.
24 MR. WEAFER: No, that's -- that's --
25 MS. ROY: If I could --
26 MR. WEAFER: Of course, yeah.

1 MS. ROY: I just want to confirm, Mr. Weafer is referring
2 to a benchmarking study that we were directed
3 undertake for the (inaudible - off microphone). And
4 what we've done, we been consulting stakeholders and
5 we have come up with a list of eight potential
6 consultants that could assist with that and we have
7 distributed that list of those eight consultants to
8 the parties that are involved in that for their
9 review, and to us procure a mutually agreeable
10 consultant. But no, we have not retained anybody on
11 that list or we haven't had major discussions with
12 them about what an engagement would look like.
13 MR. WEAFER: Thank you. And I just want to make sure
14 that that's on the record, and clear. And thank you,
15 Mr. Todd, I appreciate your response, and those are my
16 questions, Madam Chair. Thank you.
17 THE CHAIRPERSON: Okay, thank you. I see that it's
18 almost noon, so I think if we could break until 1:00.
19 Is there anything else beforehand?
20 Okay. See you at 1:00.
21 (PROCEEDINGS ADJOURNED AT 11:54 A.M.)
22 (PROCEEDINGS RESUMED AT 1:00 P.M.)
23 **T37/38**
24 THE CHAIRPERSON: Okay. Who's next?
25 MR. BYSTROM: Madam Chair, I'm sorry. There was one item
26 Mr. Gosselin was going to address, just to clarify

1 some of the responses that took place in the morning,
2 if that would be convenient.
3 THE CHAIRPERSON: Sure, now would be fine.
4 MR. BYSTROM: Thank you.
5 MR. GOSSELIN: I didn't expect a lot of discussion around
6 the rebalancing. The rebalancing is particularly
7 about 22As and Bs. And the discussion around 22 in
8 particular. So I just wanted to make clear some of
9 the things that we did in the COSA with respect to the
10 22As and Bs.
11 They're grandfathered in the application,
12 and they're grandfathered in a couple of ways. With
13 respect to their Ts and Cs, and also with respect to
14 how we allocated costs to the As and Bs.
15 So, the way we've allocated the costs in
16 the COSA is very similar to past practice, in the fact
17 that we didn't allocate a lot of distribution costs to
18 them very much at all. Because that's what we've done
19 in the past. So, consequently, their rates
20 themselves, their effective rates, are quite a bit
21 lower than their counterparts in the Lower Mainland
22 and their counterparts as proposed under rate schedule
23 22.
24 So the idea for the grandfathering was to
25 both treat them as we've honoured to treat them in the
26 past by keeping their rates similar, not the rates

1 flat, but the rate treatment or the rate derivation
2 similar to the past. Consequently, in the COSA we
3 allocated costs in the same manner.
4 So, the idea of rebalancing that rate
5 schedule is kind of not what we would have expected,
6 considering they have lower rates than, again, their
7 counterparts in the balance of the system. So, as an
8 alternative, what they could do or what the -- if we
9 decided not to grandfather that, there is -- sorry.
10 If we didn't propose to grandfather those rates, we
11 actually would have bundled them up with customers of
12 similar characteristics, which are the same
13 characteristics as the large industrials in the Lower
14 Mainland, the JV and the Hydro, where they're all
15 large industrial users, and they would have attracted
16 an allocation of distribution and transmission costs
17 as we had done for the JV, the Lower Mainland, and
18 Hydro, and all the other large industrials in FEI's
19 service territory.
20 So, I just wanted to be clear that we were
21 principled in our approach, honouring both the
22 grandfathering of their Ts and Cs, but also how we
23 allocate costs to them. That's all I have on that.
24 THE CHAIRPERSON: Thank you.
25 MR. ANDREWS: Different physical vantage point than I'm
26 used to.

1 My name is Bill Andrews, and I represent
2 the B.C. Sustainable Energy Association and the Sierra
3 Club B.C. I'll start with my questions directed
4 towards the Fortis panel, and then I have some for
5 Elenchus as well.
6 And the general focus is the revenue/cost
7 ratio, the derivation of them, the range of
8 reasonableness, and rate rebalancing as a concept. So
9 let me begin. The range of reasonableness -- it was
10 referred to this morning as a guide. And am I right
11 that Fortis is suggesting that the range of
12 reasonableness is something that is looked to by both
13 Fortis and the Commission in terms of whether there
14 should be rebalancing but it doesn't bind the
15 Commission? That's the significance of the term
16 "guide". Is that generally correct?
17 If that's a legal questions then perhaps
18 counsel would want to help out.
19 **Proceeding Time 1:04 p.m. T39**
20 MR. BYSTROM: That's my understanding but I think there's
21 some experts in the room that might be able to opine
22 on that as well.
23 MR. ANDREWS: All right I'm not asking -- I'm not trying
24 to delve into the legal nuisances of it. But I do
25 have an important follow up, is that Fortis is asking
26 the Commission to approve the 90 to 110 range of

1 reasonableness in this application, is that correct?
2 MR. PERTTULA: Yeah, that's correct and revenue-to-cost
3 ration rather than M:C, margin-to-cost.
4 MR. ANDREWS: Thank you. So then let me ask you to
5 elaborate on what you mean, what does Fortis mean when
6 it says that it's asking for approval of the range of
7 reasonableness according to the margin-to-cost ratio
8 and that it is a guide as opposed to something more
9 firm?
10 MR. BYSTROM: Maybe, Ms. Tabone, you could explain a bit
11 about the fact that even though some customer or rate
12 class might fall outside the range it's not necessary
13 required to rebalance. I think in your experience you
14 could probably explain that a bit better than I could.
15 MS. TABONE: Well, I think we have to go back, and I hate
16 to bring up the Bonbright principles because everybody
17 talks about them all the time. But the idea is you're
18 trying to balance a lot of different things; you're
19 trying to have fair and equitable rates. You're also
20 trying to have rate stability and some other things.
21 And so, when you put together a proposal, you look at
22 the cost of service as one tool to see if you've got
23 fair and equitable rates, and then you look at all of
24 the other factors as well, and you come up with a
25 whole package. And so while they may be asking for
26 approval for a range of reasonableness, what they're

1 really asking for is approval to rebalance. So, it's
2 really the rebalancing numbers that they're requesting
3 approval for and then further down the road the rates.
4 MR. ANDREWS: You had me until you went to the
5 rebalancing numbers. I took from the first part of
6 what you said that there are factors in addition to
7 the revenue cost ratio that go into Fortis's decision
8 whether to propose a rebalancing of rates. Is that
9 one step of the --
10 MS. TABONE: Right. And you could have rebalancing that
11 is not exactly equal to the range of reasonableness as
12 well. So, if you had somebody who was at a 50 percent
13 revenue-to-cost ratio you may propose to rebalance
14 them by 10 percent and not go all the way to the 90
15 percent revenue to cost ratio. So, you're looking at
16 all those things.
17 MR. ANDREWS: Fair enough. So, there are a variety of
18 factors that would affect whether Fortis proposes to
19 rebalance a particular class's rate, one of them being
20 if the revenue-to-cost ratio is outside the range of
21 reasonableness. What if their revenue-to-cost ratio
22 was inside the range of reasonableness but either
23 below or above unity. Does that become a non-factor
24 or is it still one of the factors to be considered
25 among many?
26 MS. TABONE: We view it as a non-factor. And the reason

1 is, when we look at any number between 90 to 110 we're
2 saying if they're 92 percent they're meeting their
3 cost of service. And so, we don't distinguish between
4 92 and 102, for example. We basically say if they're
5 in that range that's as close as we can get to
6 measuring whether they're paying their cost of service
7 or not. And so, you have to take some kind of range
8 at some point and break it off whether it's above and
9 below and whether they're paying their fair share.
10 But we don't think that the gradation between, you
11 know, 92 percent and 93 percent is significant given
12 all the uncertainty and the estimates and judgment in
13 a cost of service study. So, we would say as long as
14 they're in that range they're the same as each other.
15 MR. ANDREWS: Okay. So, one of the consequences of
16 changing from 90 to 110 to 95 to 105 would be that, in
17 the event that a customer class has a revenue-to-cost
18 ratio that was either between 90 and 95 or between 105
19 and 110, Fortis would consider that as a factor going
20 towards whether there might be rebalancing among the
21 other factors that would go into Fortis's decision,
22 whether to actually propose rebalancing for that rate
23 class.
24 **Proceeding Time 1:04 p.m. T40**
25 MR. GOSSELIN: Right.
26 MS. TABONE: Exactly.

1 MR. ANDREWS: Okay. So I want to just talk now about the
2 problems associated with a smaller range of
3 reasonableness. And my questions at this stage are at
4 a theoretical level. And so let me suggest that one
5 of the problems with having an increasingly smaller
6 range of reasonableness would be the potential for
7 volatility of the outcomes. That if your revenue/cost
8 ratio is changed every time, and you rebalanced every
9 time the revenue/cost ratios changed, then you could
10 end up having to change classes' rates up and then
11 down, and then up and then down, and that in principle
12 that might be considered undesirable. Would that be
13 an example of a downside of having a narrow range of
14 reasonableness?
15 MR. GOSSELIN: I think so.
16 MS. TABONE: I think so, yes.
17 MR. ANDREWS: Okay. Another one might be that -- rate
18 shock, for example. Like, that if you suddenly -- if
19 you started considering rebalancing when the
20 revenue/cost ratios are closer, then you would be
21 having to contend with the possibility of rate shock
22 that you might not otherwise have to deal with.
23 MS. TABONE: Well, I think that's more of a function of
24 moving from a wider range to a narrower range once
25 you're in the narrow range. Yes.
26 MR. ANDREWS: That is what I am trying to compare, like,

1 what is the -- what are the downsides of having a
2 relatively smaller instead of relatively bigger range
3 of reasonableness.
4 Now, just sort of totally theoretically,
5 there could be some actual costs of rebalancing.
6 Right? I'm not assuming that they would be very
7 large. But numbers would have to be crunched, and
8 time would have to be taken, to do rebalancing. And
9 so to the extent that a narrower range of
10 reasonableness means fewer rebalancings, that would be
11 another example of why you might want not to do it.
12 MS. TABONE: Yes, I think.
13 MR. GOSSELIN: There would be some costs.
14 MR. ANDREWS: But not likely to be substantial. And
15 communication costs. And in general, a lot of these
16 factors, both the concept of the fairness of the rate
17 and the response from customers, are under the
18 Bonbright acceptability principle. Is that generally
19 correct? We're talking about the rate --
20 MS. TABONE: Sure, yeah. Customer acceptance.
21 MR. ANDREWS: The customer acceptance of the rates.
22 Now, I do want to make clear here that this
23 whole topic of the range of reasonableness does not
24 engage any issue of whether the utility will recover
25 its cost of service.
26 MR. GOSSELIN: Correct.

1 MR. ANDREWS: That is, the range could be wide, it could
2 be narrow. It doesn't have any impact on whether the
3 utility recovers its cost of service.
4 MS. TABONE: Yeah.
5 MR. ANDREWS: Maybe there would be extreme versions of
6 that, but that's -- I'm talking about within
7 reasonable bounds.
8 MS. TABONE: Right. Well, typically it's more of an
9 issue between different customer classes. The only
10 issue is if you are talking about perhaps large
11 customers that you might lose if you raise their rates
12 too much.
13 MR. ANDREWS: Fair enough, yeah.
14 So, the 90 to 110 range of reasonableness
15 was approved for Fortis, or its corporate predecessor
16 in B.C., by the regulator some years ago in British
17 Columbia.
18 MR. GOSSELIN: Correct.
19 MR. ANDREWS: And Fortis is not arguing or providing
20 evidence on which it's arguing that there was some
21 kind of numerical rationale for that particular size,
22 90 to 110, as opposed to 85 to 115, or 95 to 105. Am
23 I right with that? At the time. At the time that 90
24 to 110 was approved, Fortis is not arguing that
25 there's some rationale beyond the general level of
26 what was considered appropriate. And if I'm wrong on

1 that, please tell me.
2 **Proceeding Time 1:14 p.m. T41**
3 MR. PERTTULA: It was in fact the Commission's judgment
4 that that level was appropriate. So as far as I know
5 there wasn't sort of numerical calculations or
6 anything like that, but that may have gone on at the
7 Commission rather than in any way that we would be
8 aware of it.
9 MR. ANDREWS: Yes. And you're not arguing that now in
10 any event.
11 MS. PERTTULA: Right.
12 MR. ANDREWS: Okay. So the main rationale — tell me
13 again if I'm correct — that Fortis has for keeping the
14 90-110 is that that was what was recited in the past
15 and that the accuracy of Fortis's revenue cost
16 methodology has not -- has stayed the same since the
17 time that 90-110 was approved.
18 MS. TABONE: Yeah, that's correct.
19 MR. ANDREWS: Okay.
20 MR. BYSTROM: Maybe I'll just add that we quoted the
21 Commission decisions in our IR responses. I'm sure
22 you're familiar. And the Commission did give some
23 rationale for the range of reasonableness it chose, so
24 I'm not sure if that's what you're looking at, but --
25 MR. ANDREWS: I'm trying to focus on the size of the
26 range of reasonableness as distinct from the concept

1 of using a range of reasonableness. That was the
2 intention of my questions there.
3 MR. BYSTROM: Okay.
4 MR. ANDREWS: So we've seen in the evidence that other
5 jurisdictions have -- they use the concept of
6 reasonableness for revenue/cost ratios. And the ones
7 surveyed that Elenchus has presented in the IR
8 responses have different ranges of reasonableness in
9 size. Some 95-105, some close to unity. And -- but
10 those are the way other utilities and regulators in
11 other jurisdictions deal with those utilities,
12 correct?
13 MS. TABONE: Right.
14 MR. ANDREWS: And to be clear, Fortis is not arguing that
15 it actually has evidence that its cost analysis or --
16 sorry, a revenue/cost analysis based on the cost of
17 service analysis is either less accurate or more
18 accurate than the revenue/cost methodology that's used
19 in these other specific jurisdictions?
20 MS. TABONE: Right. We didn't look specifically at the
21 other jurisdictions, but we don’t have any evidence
22 that would show we're any more precise than anybody
23 else or any less precise.
24 MR. ANDREWS: Thank you. It's been said that there are
25 multiple methodologies for determined whether a rate
26 class is paying its fair share. Let me start by -- is

1 the concept of a revenue/cost ratio is that if the
2 revenue cost/ratio is 1, at a high level that means a
3 fair share. That's what a fair share is defined as,
4 correct? Apart from we then get into --
5 MS. TABONE: Range. Okay. Apart from the range.
6 MR. GOSSELIN: Apart from the range.
7 MR. ANDREWS: It could be broader than that?
8 MR. GOSSELIN: Yeah, apart from the range.
9 MR. ANDREWS: Apart from the range?
10 MR. GOSSELIN: Yes.
11 MR. ANDREWS: Okay. So in terms of the methodology
12 Fortis has used a non-coincident peak methodology, but
13 it's aware of other methodologies that could've been
14 use to estimate the revenue/cost ratio or the concept
15 of fair share?
16 MR. GOSSELIN: I think just to be clear the methods that
17 you're referring to are cost allocation methods, not
18 different methods to estimate an R:C ratio. Rather,
19 it just estimates the C part of R:C ratio.
20 MR. ANDREWS: Right.
21 MR. GOSSELIN: So to be clear it's about cost allocation,
22 that's the method you're talking about.
23 MR. ANDREWS: So and just to digress on that point, the
24 reason that the cost is -- why we keep talking about
25 cost and service is that that's by far the more
26 complicated part of the problem. Divvying up the

1 revenue is, by comparison, quite simple.
2 **Proceeding Time 1:18 p.m. T42**
3 MR. GOSSELIN: We don't divvy up the revenue. It comes
4 in from the --
5 MR. ANDREWS: And methodology the revenue is allocated to
6 the different customer classes. And I assume that
7 that's not trivial for the people who that are
8 actually doing it. But in the big picture it's
9 nowhere near as complicated as allocating the costs.
10 MS. TABONE: Well, it's not allocated it's actually
11 forecasted based on the rates that are in place.
12 MR. ANDREWS: Fair enough, so it's a forecast estimate.
13 MS. TABONE: And it's not because we're using a forecast
14 test year, it's a forecast of revenues not historic
15 actual revenues that are known with certainty. So
16 there -- I mean there is a little bit of uncertainty
17 there because it's a forecast, but otherwise it's
18 straight forward because you know the rates.
19 MR. ANDREWS: Okay. So, when I'm talking about the
20 methodology I'm am including both, but acknowledging
21 that the cost of service is the tougher one. So,
22 Fortis is asking the Commission to approve the
23 methodology that Fortis has used in this application,
24 correct?
25 MS. TABONE: For all of the different methods that are
26 used within the COSA, yes.

1 MR. ANDREWS: Yes, the whole package that is comprised of
2 many, many different steps in determining its revenue
3 cost ratios.
4 MR. BYSTROM: I just might jump in here, since you're
5 using the word "approve", if you look to our "approval
6 sought" you're not going to find a line that says, you
7 know, the range of reasonableness is 90 to 110, so.
8 But I think that what you're getting at generally,
9 yes, that's part. Our proposals to rebalance, hinge in
10 part on approval on the range of reasonableness.
11 MR. ANDREWS: Well, my specific question here, and I
12 think it's still the same point, is that I'm asking is
13 Fortis asking the Commission to approve the package of
14 methodologies that it has used to create the
15 revenue/cost ratios that it proposes to use in
16 considering whether to propose rebalancing of rates?
17 You've provided a package of evidence.
18 You've said that, "We think that this is the best
19 methodology for the cost." I'm asking for
20 confirmation that you're asking the Commission to
21 affirm that that is the best way to go about
22 addressing this revenue cost topic.
23 MR. BYSTROM: You can -- we can each have a turn. But
24 maybe I'll just have a, like a, legal kind of
25 response, but I might make an analogy to the revenue
26 requirements. We ask in the revenue requirements

application for an approval of a rate. There's a whole bunch of things that go on in the revenue requirement. We don't ask for approval of every single line item in the revenue requirement. But in theory, practically the Commission has to approve all those things to get to the rate. Kind of similarly here with the rate design, there's all these steps along the way to get to our proposals, our rate design proposals. So, in some practical sense the Commission is approving these different components but it's not a specific line item in our approval sought. So, I'm not sure what you're getting at.

MR. ANDREWS: Well, let me put it this way. We've heard that there are different methodologies and we've heard that Fortis has selected the package that works best for it at reasonable costs. Is Fortis, and this gets back to my question, is Fortis asking the Commission to agree that that conclusion that this is the best package at a reasonable cost is actually valid?

MR. GOSSELIN: The method, first of all to clarify, the methods we used, we selected were not based on costs. Rather they were based on the best judgment or cost allocation methods that we felt were useful or rather reflected the cost causation of the utilities. So, you're saying we picked a bunch of methods based on the cost to do those methods. We didn't base it on

1 the cost, we picked the methods based on the most
2 likely way to or rather the most reasonable way to
3 allocate our costs. So, I just wanted to clarify on
4 that point.
5 MR. ANDREWS: Yeah, the reason that I specified at a
6 reasonable cost was because that is what I understood
7 your answer to be this morning when you were asked
8 whether this was the most accurate way to estimate it,
9 and I understood the response to be, "Yes, at a
10 reasonable cost."
11 **Proceeding Time 1:23 p.m. T43**
12 MR. GOSSELIN: I think that's fair.
13 MR. ANDREWS: Yes, okay. So back to -- one of the things
14 that we've heard in the topic of the size of the range
15 of reasonableness is that it needs to be taken into
16 account that there is more than one way to estimate
17 revenue/cost ratios. Fortis has chosen, done,
18 implemented, one way. And you're saying that this is
19 the best way under all of the circumstances.
20 MS. TABONE: Correct.
21 MR. GOSSELIN: I think that's fair.
22 MS. TABONE: Yeah.
23 MR. ANDREWS: Thank you. So in doing that, you've chosen
24 not to use any of these other alternative ways of
25 estimating revenue/cost ratios.
26 MS. TABONE: Correct.

1 MR. ANDREWS: Okay. Now, I just want to be very clear
2 that the same methodology, whether that's singular or
3 plural, that was used to create the revenue/cost
4 ratios for each of the classes is the same methodology
5 for each class.
6 MR. GOSSELIN: I think the answer is yes.
7 MS. TABONE: Yes, by definition, it is. Because it's how
8 you spread it among the costs, the classes, it has to
9 be --
10 MR. ANDREWS: And to flesh that out, all of the revenue
11 is included and all of the costs, or the estimates of,
12 are included in the analysis, and as a result, for
13 example, all of the revenue/cost ratios would add up
14 to 1 on a weighted basis. There is no leakage out of
15 the system.
16 MR. GOSSELIN: Well --
17 MS. TABONE: Correct.
18 MR. ANDREWS: There may be some --
19 MS. TABONE: With the exception of, like, bypass, where
20 they're not measured in the cost of service, and those
21 revenues aren't counted within one of the rate
22 classes, but they are counted in the revenue
23 requirement as an offset.
24 MR. GOSSELIN: And taking into consideration the
25 additional costs brought in by the known and
26 measurable changes. And the fact that the revenues

1 are adjusted upwards to account for that. So --
2 MS. TABONE: Yeah. Right. Yeah, they all have to total.
3 And when you look at -- if you add up all the total
4 revenues, all the total costs, the revenue-to-cost
5 ratio for the total system is 100 percent. Yeah.
6 MR. ANDREWS: That was what I was getting at. Thank you.
7 So, in terms of how the Commission decides
8 what size of revenue -- of range of reasonableness to
9 approve as a guide, let me suggest that there are two
10 basic factors. One is, its perception of the accuracy
11 of the revenue/cost estimate, and two would be the
12 cost of having to rebalance if it turned out that
13 rebalancing was proposed as a result of classes'
14 revenue to cost ratio falling outside the range of
15 reasonableness. Correct? Those are both two general
16 factors?
17 MR. PERTTULA: They are factors, but the cost part of it
18 I wouldn't expect to be material. And --
19 MR. ANDREWS: When I meant cost, I didn't mean financial.
20 I meant the downside in terms of volatility or lack of
21 customer acceptability and so on.
22 MR. GOSSELIN: I think that's -- I think that's generally
23 correct, yeah.
24 MR. ANDREWS: All right.
25 MR. PERTTULA: I mean, I'm certain those aren't the only
26 two things the Commission considers in making a

1 decision on the rebalancing, and the range of
2 reasonableness. But certainly it would be expected
3 that those two are within those -- within the things
4 that they consider.
5 MR. ANDREWS: Okay. So, if the range of reasonableness
6 is smaller rather than larger, is it correct to assume
7 that's going to mean that there will be more occasions
8 in which -- there is likely to be more occasions in
9 which a particular customer class's revenue/cost
10 estimate falls outside the range of reasonableness,
11 and hence more occasions in which there would be a
12 decision made whether to propose rebalancing.
13 MS. TABONE: In general, yes. It kind of depends on
14 where you start, but in general I would say that's
15 true.
16 MR. ANDREWS: I think those are my questions for the
17 Fortis panel.
18 And for Elenchus, these will be some of the
19 same questions. So first of all, Elenchus doesn't
20 have, or is not aware on the record of evidence that
21 Fortis' revenue cost analysis is any more or less
22 accurate than the methods used by the other
23 jurisdictions that were surveyed, is that correct?
24 **Proceeding Time 1:27 p.m. T44**
25 MR. TODD: That's correct.
26 MR. ANDREWS: And I think you've said that in terms of

1 the size, 90 to 110 percent is a reasonable range? Is
2 that correct?
3 MR. TODD: Yes, that's correct.
4 MR. ANDREWS: And that 95 to 105 would also be a
5 reasonable range?
6 MR. TODD: If that is what the Commission decided, yes,
7 that would be a reasonable range.
8 MR. ANDREWS: Well, let's take a second look at this
9 here. I mean, all of this is subject to what the
10 Commission decides, and proposals are being put
11 forward. One could say legally that whatever the
12 Commission decides is, by definition, reasonable. But
13 in your professsional opinion, is 95 to 105 a
14 reasonable range of reasonableness for the Commission
15 to adopt? Are you raising red flags about that? Do
16 you have any evidence that the Commission should take
17 into account that would suggest not adopting 95 to 105
18 as an example?
19 MR. TODD: The thought that I've thrown out is that one
20 of the considerations is consistency, the past. And
21 in order to break with tradition, if you want,
22 normally you'd want a reason for that. So, I would
23 expect, if I were the Commission, I'd say, "I'm not
24 going to change it unless there is something wrong
25 with what is happening, circumstances have changed, or
26 we think, you know, given today, 95 to 105 is more

1 reasonable." But one is not more reasonable than the
2 other, they are just different.
3 MR. ANDREWS: All right. I'm going to refer you to a
4 passage from your response to BCSEA IR 3.1 in the
5 second round, and the exhibit number is A2-14. And
6 actually, that's where I have -- I will be looking
7 both at the response and the quotation from Fortis'
8 application.
9 So, in the -- this has been referred to a
10 number of times. Fortis says -- it is quoted in the
11 preamble, and the paragraph that begins "Regulators
12 typically accept" and then it is the next sentence I
13 want to focus on now. It is:
14 "Hence, unless the level of cost recovery is
15 outside the specified range of
16 reasonableness, differential rate increase
17 would not be considered equitable since
18 small deviations from 100 percent are as
19 likely to be the results of the imprecision
20 of the methodology as they are to be the
21 results of true cost difference."
22 Do you see that?
23 MR. TODD: Yes, I see that.
24 MR. ANDREWS: And do you agree with that? Do you want to
25 qualify that? Or do you have a different perspective
26 on that?

1 MR. TODD: Yes, I think what this emphasizes is that an
2 element of fairness in the treatment of customers, is
3 are they getting equal or different rate increases, as
4 opposed to just where is the revenue-to-cost ratio.
5 Now, what is more important to an individual decision
6 is up to the regulator, but I think both of those
7 considerations play into a decision, and from what I
8 see -- again I don't sit as regulator, I sit as an
9 expert. From what I see, there is significant thought
10 in many jurisdictions given to whether you can go with
11 an across the board increase, or whether you can
12 justify the fact that certain classes get a larger
13 than average rate increase, as others get a lower than
14 average. Being outside of the range of
15 reasonableness, is generally accepted as a good
16 rationale for having some classes get different rate
17 increases than the others.
18 **Proceeding Time 1:32 p.m. T45**
19 So, what I'm actually focusing in on is one
20 of the arguments that's related to range of
21 reasonableness, and it's only one of them. And it's
22 the argument that has to do with the application of
23 probabilistic statistics to this whole topic. And
24 this sentence that I just read to you expresses an
25 approach that is based in probabilistic statistics, I
26 would suggest, and maybe I'll ask you, do you agree

with that? That the concept that small deviations are as likely to be the result of imprecision of the methodology as they are to be the result of true class difference? That's a fundamental aspect of probabilistic statistics, right?

MR. TODD: The wording is similar to what would be used in a situation which is a statistical analysis.

MR. ANDREWS: Yes.

MR. TODD: But what I have said repeatedly is, a range of reasonableness is not the same thing as a confidence interval in statistics.

MR. ANDREWS: Well, now, we haven't talked about either range of reasonableness or confidence interval yet.

MR. TODD: Yeah.

MR. ANDREWS: Okay.

MR. TODD: And what I'm saying is that the concept -- in the way you're taking these words is different than the way they're intended. We're saying there is a range. There is uncertainty about what is correct. There is also uncertainty in terms of the right way to think about and do cost allocation. There are conceptual differences when it comes to cost allocation that do not exist when you're doing a statistical analysis. Conceptually there is no --

MR. ANDREWS: So what is it about the wording that is --

MR. TODD: Sorry?

1 MR. ANDREWS: The wording says, "Small deviations from
2 100 percent are as likely to be the result of
3 imprecision of the methodology as they are to be the
4 result of true cost difference." Let me just pause
5 there. Would you agree that that statement wouldn't
6 make sense unless the corollary was that larger
7 deviations from 100 percent are somewhat more likely
8 to be the result of a true cost difference than the
9 result of imprecision of the methodology?
10 MR. TODD: Perhaps the choice of words there was not what
11 you would have liked. When I say an element of the --
12 being -- not being at 1.0, or a hundred percent, is
13 that some components of the cost of service are
14 estimated. And they may be done -- they'd be
15 estimated using a statistical technique. We saw one
16 earlier today, the regression.
17 But there are other aspects where a company
18 has to choose a methodology. If you go back -- we
19 made reference on page 3, footnote 2, of the first
20 report, to the NARIC cost manual, cost inflation
21 manual, which is for electricity, not for natural gas,
22 but the concepts are the same. They go through four
23 different aspects, and the strongest one may be in
24 that context the functionalization of infrastructure
25 costs. They go through a list of completely different
26 approaches based on a different mindset.

1 MR. ANDREWS: And the one that they chose --
2 MR. TODD: And one's not right and the other's not wrong.
3 MR. ANDREWS: -- you have said is appropriate, correct?
4 MR. TODD: No. What I've said is, a choice is made and I
5 may favour particular ones. Other experts favour
6 different ones.
7 MR. ANDREWS: I thought you reviewed the EES methodology
8 and concluded that it was appropriate.
9 MR. TODD: Appropriate --
10 MR. ANDREWS: You acknowledged that they had choices to
11 make and that, in the end, their choices were -- with
12 the exception of the four that you noted, you said
13 that they were appropriate.
14 MR. TODD: Don't -- don't read more into the word
15 "appropriate" than was intended. There is a
16 difference between saying "appropriate" in the sense
17 of being right, and being appropriate as being
18 acceptable. There may be three different approaches,
19 two or three different mindsets, each of which has a
20 rationale to it. Each of which is acceptable and
21 appropriate. But none of those three is right and the
22 others wrong. So, all we've said is, what they have
23 done is within the realm of reasonableness. It is
24 appropriate, it is consistent with common practice.
25 Others do things differently, sometimes in very
26 similar circumstances. Those can be correct too,

because they are not incorrect.

Proceeding Time 1:36 p.m. T46

MR. ANDREWS: So, let me take you back to the actual question, which is related to the concept embedded in this statement, that there can be such a thing as small deviations that are as likely to be the result of imprecision as the result of a true cost difference. And I suggest to you that that only makes sense if it also follows that larger deviations are more likely to indicate a true cost difference, or true revenue cost difference than simply imprecision in the model. Would you agree with that?

That's why it uses the word "small", because they're not big. The statement is not gigantic deviations from 100 percent are as likely to be the results of imprecision of methodology as they are to be the results of true cost difference. It's "small deviations".

MR. TODD: The differences in different methodologies would give different results. A large deviation is something which is more likely that you'd get the same deviation whatever your methodology, whatever your cost allocation methodology. That is all I'm saying.

MR. ANDREWS: We're not comparing methodologies, we're comparing sizes of deviation. The statement is, that small deviations are as likely to be the result of

1 imprecision of the methodology, compared to the
2 results of a true cost difference. And I'm asking you
3 to comment on the implication of that is that larger
4 deviations are less likely to be the result of mere
5 imprecision, and are more likely to be the result of a
6 true cost difference.
7 MR. TODD: What you're doing is taking a paragraph out of
8 context of the full report, and trying to give it
9 meaning that is not there. Meaning that is there says
10 that there are different ways you can do a cost
11 allocation study that will give different results, all
12 of which are valid, all of which are legitimate
13 different ways of approaching it. If you take one
14 particular one, and you must choose one method for any
15 particular company in any particular jurisdiction, the
16 larger the deviation, i.e. the larger the range of
17 reasonableness, the more certain you are that no
18 matter how you do the cost allocation, you'd come up
19 with the same directional impact.
20 MR. ANDREWS: So, what you just said, applied to multiple
21 methodologies, the same analysis that I asked you
22 about to do about one methodology, and in both cases -
23 - I mean what I understood you to just say is that in
24 any methodology, the larger the deviation from one,
25 the more likley the results are indicative of the true
26 difference, compared to imprecision in the

1 methodology? And I am proposing that as a pretty
2 straightforward conclusion.
3 MR. TODD: You are proposing that, but I am disagreeing
4 with you, because implicit in your question is the
5 assumption is that there is one correct and true
6 allocation of classes. What I'm trying to say is
7 there is no single true underlying allocation, that is
8 the right number, similar to doing a survey of public
9 opinion. If you surveyed everybody in the country,
10 you would get a true result of the opinion. When you
11 do a sample survey, you get an estimate of that true
12 underlying value.
13 Here, there is no true underlying value in
14 terms of allocating costs. You are not using a
15 statistical estimation technique, you are doing
16 different methods that are trying to define equity.
17 MR. ANDREWS: Well, come on now. Let's talk about,
18 instead of talking about directionally, let's talk
19 about range of reasonableness. The fundamental
20 concept of the range of reasonableness, the way it is
21 used here, is that if a deviation is not small, but is
22 outside of the range of reasonableness, then it has
23 significance. There is a likelihood that the results
24 are the result of a true cost difference. That's why
25 we have the range, so that inside we can determine --
26 we don’t take it into account. And if it is outside,

1 we do. We take it into account because we think that
2 because it is outside the range of reasonableness, it
3 may reflect a true difference in the revenue cost
4 ratio, correct?
5 MR. TODD: Yes, but let's be clear --
6 MR. ANDREWS: That's why we would then use it as input
7 into whether we should rebalance.
8 **Proceeding Time 1:42 p.m. T47**
9 MR. TODD: Yes, but let's use the words carefully. It is
10 called a range of reasonableness, for a reason. It is
11 saying that within that range or reasonableness the
12 rates your charging customers in order to recover
13 costs are reasonable. It's not saying that 99 is more
14 reasonable then 97. It's saying that if you accept
15 the range of reasonable 90 to 110, that 91 is
16 reasonable, 95 is reasonable, 100 is reasonable, 105
17 is reasonable.
18 MR. ANDREWS: Would you agree that -- sorry. Would you
19 agree with me that if one customer class had a range
20 at a revenue cost ratio of 89 and another had a
21 revenue cost ratio of 5, that the inference is that
22 the one with 5 is more out of balance with its revenue
23 to cost than the one with 89? They're both outside
24 the range of reasonableness so we're not saying
25 they're automatically identical. But would you agree
26 that there is some directionality there to the number?

1 MR. TODD: Yes, they both need adjustment. One would
2 require more adjustment than the other, I agree.
3 MR. ANDREWS: Thank you. Those are my questions.
4 THE CHAIRPERSON: Commission staff?
5 MR. SOUTH: I have some questions for both FEI and
6 Elenchus. And I'll go back and forth some of the
7 time, but I think that should be okay with both of
8 you.
9 Okay, so the first question is towards FEI,
10 and it goes back to the Bonbright, more of a general
11 question. So, on page 9 of the COSA Report, Exhibit
12 A2-2. Elenchus states that,
13 "To establish a principle cost allocation
14 approach consistent with Bonbright's
15 principle number 6, regulators generally
16 adopt a view that the class that causes
17 specific cost should be expected to pay
18 these costs. This is referred to as the
19 cost causation principle."
20 Further on in the paragraph, Elenchus says:
21 "Enbridge also mentioned in its cost
22 allocation studies that the overriding
23 principle for proper classification and
24 allocation of costs is to do so based on the
25 causation of costs that are approved by the
26 OEP."

1 Can FEI confirm or otherwise explain that FEI did not
2 utilize an overriding principle such as cost causation
3 during the development of its COSA study?
4 MS. TABONE: Confirm that they did not?
5 MR. SOUTH: Yes.
6 MS. TABONE: No, they absolutely looked at cost causation
7 when they put together their cost of service study and
8 the different methods.
9 MR. SOUTH: No, what I mean is that as a single defining
10 overriding principle that that would always be the
11 number one principle in terms of -- say you have the
12 Bonbright Principles or FEI lists eight principles.
13 Is there one key principle that's always the
14 overriding principle?
15 MS. TABONE: No, and in fact they listed in their
16 application multiple principles that they looked at.
17 MR. SOUTH: All right, so I guess could you elaborate on
18 why Enbridge would have one overriding principle and
19 why FEI would choose not to have an overriding
20 principle?
21 MR. TOKY: Sorry, can I just interject? Can you please
22 repeat your question number 1? Because I just want to
23 try and understand what you mean by the overriding one
24 principle. When we, you know, came up with our
25 results for the COSA, is that what you mean? Or, like
26 I just want to understand, can you please repeat the

1 question once again?
2 **Proceeding Time 1:47 p.m. T48**
3 MR. SOUTH: Okay, so you have a -- you have the Bonbright
4 Principles and FEI lists principles, right? And what
5 I want to know is that, so that's if FEI has one
6 principle that overrides all principles? Like, in
7 terms of one principle that has more priority than all
8 the other principles and if it applies that
9 consistently throughout when making all the
10 assumptions and judgments, or does it change -- does
11 the principles change priority based on each
12 assumption and judgment that FEI has to make?
13 So in Elenchus's report it mentions that
14 Enbridge,] mentions that in its cost allocation it has
15 an overriding principle for proper classification and
16 allocation of cost and it does so based on the
17 causation of cost and that's their overriding
18 principle.
19 MR. TOKY: Thanks for clarifying the question. I think
20 we are talking more in terms of the redesign and not
21 really the cost allocation piece here. Because the
22 cost allocation exercise that we do or the COSA study
23 that we do is primarily -- that primarily takes into
24 consideration the cost causation. And that's one of
25 the principles -- that fits in with one of a couple of
26 principles within the Bonbright principles. But when

1 we come up with the rate proposals, then, yes, we have
2 used -- depending on where and what kind of proposals,
3 you know, we're making, depending on where the
4 situation is, we have used different principles. But
5 I think this is, like, really a little bit outside
6 what we are talking about in terms of the rate design.
7 That's what I think.
8 MR. SOUTH: So I guess, so just to confirm, in the cost
9 allocation you focus on cost causation every time
10 consistently and that was the principle that you used
11 to allocate cost?
12 MR. TOKY: Yeah, Rick, if you want to just take that.
13 MR. GOSSELIN: Yeah. When you look at the principles,
14 the Bonbright principles that we listed in section
15 1.2, number 2 in particular speaks to the fair
16 appointment of cost and the fair appointment of cost
17 is really about the cost causation. So that was the
18 general overriding principle used when allocating cost
19 in the COSA, is to be as principled and as fair, and
20 as reasonable as possible.
21 MR. SOUTH: Okay. Okay. All right. So I think that
22 answers my question with that.
23 All right, so the next question is for FEI
24 again. And this is about quotes you use in historical
25 actuals, approved forecast figures. So on page 5 of
26 Elenchus's COSA report they do say that cost of

1 service allocation studies can be done using
2 historical actual data or using future test year data.
3 And in response to a BCUC IR 2.1, Elenchus goes on to
4 say that the disadvantage of using the most recently
5 approved forecast year is that the expected operating
6 conditions in the forecast year may not materialize
7 and actual operating expenditures may be different
8 from that which was forecasted. In the event that a
9 COSA study is undertaken in conjunction with a
10 regulatory review of the future test year revenue
11 requirement, the approved COSA methodology can be
12 rerun based on the approved revenue requirement to
13 ensure consistency prior to setting final rates for
14 the test year.
15 I guess the question is what are FEI's
16 views on rerunning any COSA calculations and
17 methodology based on the most recently approved
18 revenue requirements as opposed to the 2016 approved
19 revenue requirements? I guess you can just elaborate
20 on would it be significantly different results and how
21 difficult would it be to rerun the COSA?
22 MS. TABONE: And are you thinking of looking, for
23 example, at a 2016 historic year or looking at a 2017
24 forecast year?
25 **Proceeding Time 1:52 p.m. T49**
26 MR. SOUTH: Like 2017 forecast approved year based on --

so you did the 2016 forecast approved, and then -- say, for example the 2017 one has been approved. Were there any significant changes, and how easy is it for you to re-run the COSA using the 2017 approved figures. Would it yield different results?

MR. GOSSELIN: Let me answer that one for you. First of all, the approvals sought – rather the change in rates that we proposed through the application – have really been based on 2016 annual review, plus noted measurable changes. So we're trying to get a view of what 2018 will look like. And then the proposed changes are actually in fact that. They're the changes we're asking for, not an approved rate. So the changes we're asking for will be applied through rates in places and times.

So, I don't expect -- sorry. So that's one thing.

Now, to rerun a COSA model using perhaps 2018 approved revenue requirements, wouldn't be terribly difficult as long as all -- you're not expecting an update on all the minimum -- like, all the supporting studies and customer segmentation. And the cost for this whole process is -- you know, we have estimated it at two and a half to three million dollars. We wouldn't want to impose a whole bunch more costs onto this process, just to get immaterially

1 closer to a perfect rate. Considering, you know, we
2 have to look at the costs of the COSA study and all
3 the rate design under a lens of, you know,
4 reasonableness and a number of principles that we've
5 identified in the application.
6 So, to your point, I don't think -- I'm
7 fairly certain it wouldn't result in material
8 differences. And you know, to a limited degree it's
9 possible. But we -- you'd be -- you'd certainly want
10 to be aware of the additional costs of doing so, given
11 the benefits that you get out of it.
12 MR. SOUTH: And so let's say hypothetically there's a
13 methodology and everything is approved, and you don't
14 have to go through this process again. Would the
15 costs be more reasonable? Like, significantly more
16 reasonable? To just re-run it?
17 MR. GOSSELIN: I -- that's likely, but I'd have to, you
18 know, give it some thought about the things that we
19 need to do. Yeah, re-running it with the latest
20 revenue requirements, all else being equal, shouldn't
21 be terribly difficult.
22 MR. SOUTH: Okay. All right.
23 All right, so the next few questions are on
24 load and costing data using the COSA. So, in response
25 to BCUC IR 14.2, and this is in Exhibit B-5, FEI
26 discusses the quality of its customer data, load data,

1 and costing data. So, I'll just read it for the
2 benefit of everybody here.
3 "For residential, small commercial, and
4 large commercial sales service, which make
5 up the majority of the COSA demands, the
6 available data is from monthly customer
7 reads, which occur in multiple cycles
8 throughout the month. This is an
9 improvement from 1993 when these customers'
10 meters were typically read every second
11 month. However, even with these
12 improvements, the necessary data to know
13 what actual customer consumption is during
14 peak conditions is not available. As such,
15 the load factors of individual customers,
16 and even the residential and commercial
17 classes as a whole, continue to be estimates
18 -- meaning there is still a measure of
19 uncertainty in the demand allocators in the
20 COSA."
21 **Proceeding Time 1:56 p.m. T50**
22 So, in response to BCUC IR 18.2 on the rate design
23 report, which is Exhibit A2-11, in that question,
24 Elenchus was asked to explain if and how each of the
25 utilities listed in a specific table have the
26 capability of determining actual customer consumption

1 during peak conditions. In response Elenchus states
2 that:
3 "Utilities generally rely, at least in part,
4 on estimated load profiles for some or all
5 of their customer classes. In Elenchus's
6 experience, the estimated load profiles are
7 typically based on load research which
8 involves detailed consumption data based on
9 detailed metering of a statistically
10 significant sample of customers or reliance
11 on data from comparable utilities. These
12 load research methods are considered to be
13 the most cost-effective way to derive
14 suitable load profiles for use in both
15 systems planning and cost allocation."
16 What is FEI's view of Elenchus's response to BCUC IR
17 18.2 in terms of the quality, considering the quality
18 of the data used in the COSA?
19 MR. GOSSELIN: So, one of the things I want to bring
20 attention to, is recalling from the presentation I put
21 out earlier is certainly having a statistical sample
22 will provide you with more data points. Because the
23 meters that you can put in place are likely demand
24 meters and you're getting daily reads. In some case
25 hourly but I suspect daily for gas. That will provide
26 you a sample of which you can infer a population

1 result. The sample you'll get is likely going to be
2 in the same range or very similar range as FEI has
3 looked at anyways because of our typical temperatures
4 are zero to twenty, we don't frequently get minus 10
5 or minus 15. So, FEI looked at the entire population
6 and inferred some data points from which we've done a
7 regression.
8 So, you can look at it, you could start
9 with a much smaller number of people, a sample, and
10 get more data points to infer a peak day. Or you can
11 look at the entire population, use those data points
12 to infer peak day. So, I'm not sure if one is better
13 than the other in particular, I just know that using a
14 sample you're going to have some margin of error.
15 Using the population, you'll have less margin of
16 error. Using the sample, you will get more daily
17 reads but on the population less daily reads but
18 perhaps more certainty around the regression analysis
19 to get to a peak day.
20 So that’s my opinion on the two methods to
21 get load data.
22 MS. TABONE: And can I just add something? In terms of
23 Fortis on the electric side and BC Hydro, they do have
24 -- well, BC Hydro certainly has had load research
25 programs in the past to collect that information.
26 Right now, we're working on FortisBC and they have AMI

in place, so now they have all that, you know, hourly data from all of their customers. But on the electric side you're always looking at normal weather conditions and so you can measure that by looking at a statistical sample. Here, again what Rick was saying, you're trying to measure this 1-in-20-year occurrence, so unless you've got 20 years' worth of daily data you probably aren't going to get the loads at that peak days. So, you're still going to have to do some regression to get to that point, so it's not going to be as certain as you would have on the electric side.

MR. SOUTH: So I guess follow up to that, to you Gail, how does that compare to how other utilities estimate that peak day demand data?

MS. TABONE: Yeah, I don't have specific information for the utilities Elenchus looked at or what we did, because that's usually something that's rather buried in a cost of service study. And it might not be specifically discussed in the orders or the application because it's something they do internally to come up with their load estimates. So, I don't have good information about specific utilities, but in general I would say large utilities do tend to do a load research sample. It's pretty standard.

MR. TOKY: I would just like to add something, just to put this in the overall context with the cost of

1 service allocation study. The part that you're
2 talking about in terms of the quality of the data is
3 only to deal with the demand related costs. I mean
4 coming up with those peak day demand numbers. There is
5 other generalizations, estimations, judgments we used
6 in the cost of service allocation study as well, so I
7 just wanted to make that point clear.
8 **Proceeding Time 2:02 p.m. T51**
9 MR. SOUTH: Right, and to be clear, the demand related
10 cost is about 50 percent, correct?
11 MR. GOSSELIN: That's correct.
12 MR. SOUTH: Okay, so I guess in terms of in response to a
13 technical question, BCUC 5.1, Exhibit B15, FEI
14 provided information regarding the amount of demand
15 meters that is currently installed. So, there is a
16 table there with several rows of data. The table
17 shows that all industrial customers have demand
18 meters, and large commercial customers, accounting for
19 about 33 percent of the 2016 large commercial peak
20 demand, also have demand meters. When combined, the
21 peak demand accounted for customers with demand meters
22 is about 12 percent of total peak demand. This
23 question is more for Elenchus.
24 Can you tell me if other utilities, in your
25 experience, is set up similarly to FEI where
26 industrial customers have demand meters, and

1 residential customers and small commercials don't?
2 MR. TODD: Yes, demand meters are more expensive, and
3 typcially you only -- a utility will only install
4 demand meter where they are charging a customer on the
5 basis of their demand, as well as their total volume.
6 That is when you pay the premiums. It is not for load
7 research or load profiling purposes, it is for billing
8 purposes.
9 And it is important to recognize that a
10 demand meter, the ones I'm familiar with, where they
11 are labeled "demand meter", measure demand in the
12 month. It doesn't tell you what the coincident peak
13 demand is. But of course for large volume customers,
14 typically there is minimally heat load, therefore
15 their demand is fairly constant. So, it is a pretty
16 good indication of peak demand.
17 It's the lower volume customers that don't
18 have demand meters where you don't have as good a fix
19 on their demand monthly, let alone their coincident
20 peak demand.
21 MR. SOUTH: Right, and so I guess would it be the same
22 difficulty as that FEI is having in estimating the
23 peak demand of the lower volume customers that other
24 utilities would have?
25 MR. TODD: Yes, every utility has that issue. Every
26 utility has to address it. Some do it through

1 regression, the way FEI is doing it, some do it
2 through load research. Some will do a combination of
3 both.
4 MR. SOUTH: Okay, so in terms of FEI's customer data, and
5 load data, and costing data, bearing in mind all of
6 that, would you say it's of a significantly less
7 quality than other utilities?
8 MR. TODD: I don’t think I could judge on that. Yeah, I
9 mean we've said we don’t have the information, so we
10 can't pass judgement on that, and it is in response to
11 18.3. Be consistent with that, they are -- the
12 regression technique is different than the load
13 research technique. Either one is going to give you
14 an estimate. Either one is going to be imperfect. We
15 would have to go through a number of utilities and do
16 it both ways to see whether there is even a
17 significant difference between the two methods.
18 MR. SOUTH: Okay, so I guess the takeaway from that is
19 that generally utilities estimate, and there are
20 different ways to estimate?
21 MR. TODD: And both are considered acceptable.
22 MR. SOUTH: Okay, thanks. So, that seemed to have
23 answered some of those questions. The next set of
24 questions, I think, is mostly for Elenchus.
25 **Proceeding Time 2:06 p.m. T52**
26 So, on page 33 of Exhibit A2-10, Elenchus's

1 rate design report, Elenchus provides Table 4, with
2 R:C ratio range of reasonableness. I think this table
3 has come up several times today.
4 MR. TODD: Yes, it's attracted a lot of attention.
5 MR. SOUTH: Yeah. So, in response to BCUC IR 17.1 on the
6 rate design report, Elenchus states that Alta Gas and
7 Atco do not include commodity storage and transport
8 costs in their COSA model. Sask Energy excludes
9 commodity costs, but includes storage and transport
10 costs, in its delivery service rate application. And
11 Union, Enbridge, and Centra Gas include commodity
12 storage and transport costs in their COSA model.
13 I think you touched on this this morning,
14 but I just want to, like, make it as crystal-clear as
15 possible. Can you confirm that when other utilities
16 use the term "R:C ratio" or "revenue-to-cost ratio" it
17 does not necessarily mean that it includes gas costs
18 in the manner that FEI uses the term?
19 MR. TODD: That's correct. It's got to be looked at on a
20 case-by-case basis.
21 MR. SOUTH: Okay. So, can you confirm that of the
22 utilities listed in Table 4 of the rate design report,
23 the utilities that include gas costs or a portion of
24 gas costs, in their revenue-to-cost ratios have a
25 smaller range of reasonableness than the other
26 utilities? And that Union, Enbridge, and Centra Gas,

they are close to unity, close to unity on a hundred percent.

MR. TODD: That's correct.

MR. SOUTH: Okay. So, and I guess another statement I want you to confirm or otherwise explain is that Alta Gas and Atco both who have a range of reasonableness of 95 to 105, they use what would be the equivalent of FEI's M:C ratio.

MR. TODD: That's correct.

MR. SOUTH: Okay. So I guess to sum up, two utilities that use FEI's M:C ratio have a range of 95 to 105, and then three utilities that use FEI's R:C ratio have a range of reasonableness of even smaller than 95 to 105.

MR. TODD: That's correct.

MR. SOUTH: And this is with the similar industrial customer data, and estimation of stuff like heat demand for lower volume customers?

MR. TODD: I'm not certain on that similarity. As we commented before, we don't know exactly what their load research is, and so on. So it's hard to make that comparison. But we don't have evidence of differences. But that is lack of evidence not -- there's an absence of differences.

MS. TABONE: Okay, I do know one thing for Atco. I think they only have two customer classes. They have low-

volume and high-volume. So they aren't looking at eight or ten different customer classes when they're doing their cost of service.

MR. SOUTH: Okay. Okay. And I guess another question for Elenchus. So with R:C ratios, the gas costs are included. And by gas costs, I mean, commodity storage and transport. Let's say hypothetically gas costs go from $3 per gigajoule to, say, $9 or $10 per gigajoule, and all else remains the same. What would be the effect on the R:C ratios directionally. Would it approach unity or get worse? Like, say it was 95 percent. Would it approach unity or go to 90 percent or --

MR. TODD: In the absence of a pass-through of those costs, if costs go up and revenues stay where they are, then the revenue/cost ratio will be going down. If it's a significant increase. It could be going down significantly. But it's important to recognize that most gas utilities are flowing through their gas costs, that that part of the price adjustment mechanism if you want, is automatic or relatively authomatic. And that is part of kind of keeping it closer to one. Without a pass-through of the gas costs, which are market based rate, not a cost based -- commodity costs are not based on a fully elegant costing study, it is market rates. That would cause

1 significant deviations if they are not passed through
2 on a relatively automatic basis.
3 **Proceeding Time 2:12 p.m. T53**
4 MR. SOUTH: Okay. And that concludes my questions.
5 THE CHAIRPERSON: And are there any other questions from
6 interveners? So --
7 MR. SOUTH: We still have some more people.
8 THE CHAIRPERSON: Oh, sorry.
9 MS. TRAN: Okay, so my first question I'd like to address
10 to Elenchus. And the topic is the Tilbury Expansion
11 Project. So, this question is from the BCUC to
12 Elenchus, so the response is in Exhibit A2-5, BCUC IR
13 8.1 and 8.1.1.
14 So, in response to BCUC IR 8.1, you explain
15 what is the standard approach for the treatment of
16 large projects in COSA studies. And when the
17 Commission asked you to provide an example from
18 another jurisdiction to support this response, you
19 referenced the Greater Toronto Area project in IR
20 8.1.1. Can you please briefly explain what this
21 project is about, and why it is a useful comparison to
22 the Tilbury Expansion Project?
23 MR. TODD: The Greater Toronto Area is Toronto and the
24 region around it, which has been experiencing massive
25 growth. And as a result, Enbridge Gas Distribution,
26 which services the GTA, as well as other parts of the

1 province, undertook a major, I should say, broad-based
2 upgrade to the capacity of their distribution system.
3 I think it was -- I can't remember now, I think it was
4 separate from the upgrades they did for gas fire
5 generation in sort of the downtown Toronto area. That
6 was another major upgrade. Mike and I were involved
7 in hearing around the cost allocation there. And it
8 was dealing with that upgrade separately, so I'm
9 pretty sure that project is separate from the GTA
10 upgrade, if my recollection is correct. But I'm not
11 certain.
12 So, it was a very significant upgrade
13 project. In order to reinforce and strengthen
14 deliverability to the growing population demands in
15 the Greater Toronto Area. Clearly, that project would
16 not have served other Enbridge customers outside of
17 the GTA area. But, you know, it is still a rolled-in
18 approach. So, the concept there is you can have major
19 projects which become part of the cost of the system
20 generally, could be categorized, cost based on the
21 function being served by those costs. Sometimes there
22 are spin off consequences, such as in the case I
23 mentioned with gas- fired plants.
24 There was a plant in downtown Toronto that
25 led to -- when Mike and I were involved, that led to a
26 rethink about actually the definition of "customer

1 classes". The definition of "customer classes" is a
2 way to deal with the impact, if you want, of specific
3 projects, which, in effect create, different
4 categories and customers. That was a very different
5 example, and I don't think that part of it is
6 applicable to the Tilbury system that I'm aware of.
7 MS. TRAN: Thank you.
8 MR. GOSSELIN: Could I add something to that?
9 MS. TRAN: Yes.
10 MR. GOSSELIN: I think you're trying to draw a similarity
11 between the Greater Toronto area project and the
12 Tilbury Expansion Project, is that correct?
13 MS. TRAN: Well, I, particularly, am not trying to draw
14 these simularities, but the response that Elenchus
15 provided to a Commission question mentioned the
16 Greater Toronto Area Project, so I just wanted to know
17 how similar, or how dissimilar they were.
18 MR. GOSSELIN: Okay.
19 MS. TRAN: But my other questions were on the same topic,
20 and were for FEI. So you might have a chance to
21 elaborate on that.
22 MR. GOSSELIN: Okay.
23 **Proceeding Time 2:18 p.m. T54**
24 MS. TRAN: In your application on page 6-11, FEI
25 mentioned that it used a 10-year lead wise marginal
26 approach in the COSA model to more accurately reflect

1 the ongoing impact of this project on customers. So,
2 my question is would other projects not also have
3 ongoing impacts on customers even if they are, they
4 have no associated revenues?
5 MR. GOSSELIN: Yes, all the projects that we have
6 included as part of the known and measurable changes
7 have impact on customers. The one difference that
8 Tilbury has from the other major projects we have
9 included and also perhaps different than the GTA
10 project as described by Elenchus is the fact that it
11 has a distinct revenue stream, and not a revenue
12 stream for our existing customers that are there on
13 the system, but a revenue stream that -- from new
14 customers that this particular asset is being built
15 for. So, as that LNG market develops, the LNG
16 customers, the expected revenue stream should grow
17 over time to the capacity of the system.
18 So, just to reiterate from my presentation
19 this morning, we were trying to get a view of Tilbury
20 on a, we'll call it an average or a 10 year levelized
21 or 10-year average view of its costs and revenue
22 stream impact on customers. So that if you use it in
23 a rolled-in approach you get slightly different cost
24 allocations. Then you do a COSA in about four to six
25 years and you might get a different set of cost
26 allocations because of the difference in revenue that

1 will come in over time. And what that could cause is
2 some rate instability for customers because at one
3 point it will assume -- it will have some cost
4 allocation impacts one way and then five or six years
5 later, seven years later, it'll have cost allocations
6 impacts another way.
7 So, to mitigate that possibility of rate
8 instability for our customers, we did it on a
9 levelized approach.
10 MS. TRAN: Thank you. So, would that, in your view,
11 qualify as extraordinary circumstances justifying
12 exceptional treatment? And my question refers to the
13 response to CEC IR 16.1.1 in Exhibit A2-8, where
14 Elenchus recommends:
15 "FEI to use the standard rolled-in
16 methodology practice unless FEI provides
17 additional information demonstrating
18 extraordinary circumstances justifying
19 exceptional treatment."
20 So, what you've just explained, would you
21 say --
22 ME. GOSSELIN: Yes, I would consider that information
23 that should enable us to have extraordinary treatment
24 of Tilbury expansion, when we include it in the COSA,
25 yes.
26 MS. TRAN: Thank you. And finally, do you know if other

1 utilities have used this same approach for similar
2 large projects?
3 MS. TABONE: We have not come across this type of
4 approach before but I think it's just due to the
5 circumstances. I mean typically when you have a
6 project, it's a project that's going to benefit all
7 the existing customers or maybe it's just benefiting
8 new customers on the system, but they're still within
9 the existing customer classes. This one is just so
10 different because it's a whole different class of
11 revenues and I guess if you were to look at it more
12 traditionally and wanted to make known known and
13 measurable changes you'd probably have to add this LNG
14 market as another customer class not just ignore it
15 completely and just look at the cost. So, the changes
16 would be a lot more significant if you went down that
17 road, but you can't add the cost and not look at the
18 revenues. To be fair to the other customers.
19 MS. TRAN: Thank you. And I just have a couple more
20 question for Elenchus on a different topic. The next
21 one is on the MSS review.
22 **Proceeding Time 2:23 p.m. T55**
23 In your report on page 15, so that would be
24 Exhibit A2-2, you've mentioned that MSS and PLCC
25 reviews are only required when there is a reason to
26 believe that the latest study needs to be updated, for

1 example, if the distribution asset minimum standard
2 changes. And one of the questions the Commission
3 asked in BCUC IR 6.1 -- that would be Exhibit A2-5.
4 The BCUC asked in what year Union Gas and ATCO most
5 recently updated their MSS and why they updated it.
6 Do you know what prompted Union to review
7 its MSS in 2011?
8 MR. TODD: No, we don't know specifically what prompted
9 it. We just know they did. The Union system has been
10 evolving over time. I can say there was not a
11 dramatic change in the systematic point in time. I
12 would note that in Ontario there is an evolution of
13 more system expansion into, say, more rural areas, so
14 it may well be that the average customer density would
15 have declined over time and ongoing decline in
16 customer density would be a reason to do an update.
17 MS. TRAN: Okay, thank you. And my last question is
18 related to the cost allocation methodology for Mt.
19 Hayes LNG storage, and in response to BCOAPO IR. So
20 in Exhibit A2-6, IR 2.2, BCOAPO asked:
21 "What customer classes are most affected by
22 the classification methodology used by FEI
23 as compared to the comparator utilities when
24 using more traditional classification
25 methodologies?"
26 And in the response Elenchus states that:

"If all Mt. Hayes costs were functionalized as storage, costs allocated to transportation customers, for example Rate 25, in FEI's current method will be shifted to sales customers, for example Rate 6."

Can you confirm that you meant that costs will be shifted to all sales customers?

MR. TODD: Yes. I'll double check that. I'm pretty sure. In fact I seem to recall inserting that word in reviewing the drafts.

MS. TRAN: Thank you. I don't have any more questions.

MR. SOUTH: I have one follow-up question.

THE CHAIRPERSON: Okay. Commission staff are finished.

MR. SOUTH: Yeah. I was wondering if he was actually double checking it now?

MR. TODD: Actually I did double check. This is not the place where I stuck, put in an "all", that all would apply.

THE CHAIRPERSON: Okay. Are there some follow-up questions?

MR. MARTISKAINEN: Yes. Jouni Martiskainen, Catalyst Paper. Just a quick follow up question to comments we had after the lunch break.

In terms of the I guess historical treatment of distribution costs or distribution plant, I know we spoke this morning about 22A and 22B not

1 having any distribution costs allocated. And, again,
2 as a high-pressure transmission system customer that
3 historically you have joint venture BC Hydro on the
4 other side on the island, again, historically
5 allocated zero costs for distribution, strictly
6 transmission allocation of costs. Going forward again
7 there's the proposed RS22 where that changes for two
8 customers, but not for other folks.
9 How does that relate to I guess principle 2
10 and principle 8 for fair apportionment of costs and
11 undue discrimination among similar types of customers?
12 If you can comment on just the difference in treatment
13 on the distribution rate base, why now would those
14 costs coming for transmission customers on the Island
15 that had historically not paid distribution costs, nor
16 been allocated distribution costs historically?
17 MR. PERTTULA: What we've been trying to do in this
18 application is establish, as much as possible, postage
19 stamp rate structures, and so that meant bringing all
20 the industrial customers together, and in some cases
21 they do have distribution costs and in other cases
22 they don't.
23 **Proceeding Time 2:28 p.m. T56**
24 But one benefit of, let's say, of postage-
25 stamping for the customers on Vancouver Island is,
26 they're much, much further along on the transmission

1 system but we're not trying to impose any sort of
2 demand distance charges or anything like that on
3 Vancouver Island customers. But as part of the
4 amalgamation and postage stamping, it was thought that
5 bringing those groups together was the best solution.
6 And then the grandfathering of the other rate classes
7 is really just a continuation of the treatment that
8 they've had for a long period of time.
9 MR. MARTISKAINEN: But in terms of the allocating of
10 distribution costs to customers that historically have
11 been, and would continue to be, transmission customers
12 in a high-pressure system, what's the reasoning for
13 all of a sudden taking a large amount of rate base and
14 allocating it to those same customers that again -- we
15 talked about one COSA being similar to other COSAs and
16 being accurate and reasonable. This is quite a
17 significant deviation from previous cost of service
18 with TGVI and FEVI.
19 MR. PERTTULA: You can look at that from the perspective
20 of a customer that's on the distribution system. They
21 might be just a short distance off the transmission
22 system, just by the circumstances of where their plant
23 or operation is located. And now they're getting
24 service off the distribution system, so they would
25 have a -- you know, logically a distribution
26 allocation. But you know, they're not that much

1 different, and it's only in some cases a very short
2 distance of pipe that's on the distribution system.
3 So, in the overall principle of postage-stamping and,
4 you know, sort of the same treatment for the same
5 types of customers, it's a situation where it's both
6 distribution and transmission that's been allocated.
7 MR. MARTISKAINEN: Okay, so there is not looking at
8 postage stamps for high pressure transmission systems
9 and a postage stamp for distribution systems. This is
10 sort of a mixture of transmission pressures, low-
11 pressure distribution, mix them all together and come
12 up with an average.
13 I'm trying to relate to, for example,
14 electricity in the province. You have transmission
15 voltage, you have distribution voltage, you have lower
16 voltage, different costs, different rates, sort of,
17 for different customers. And here we seem to be
18 mixing transmission and distribution customers into
19 one pot. And then the other question again around
20 postage stamps, where between 22A and 22B there is 14
21 customers that are not getting postage stamped.
22 There's two customers on the Island that are proposed
23 to go postage stamp, plus Creative Energy. So if you
24 look at the lump sum there that are not bypassed, most
25 of them are completely unaffected by the proposed
26 postage stamp, if it's only applying to -- you know,

1 on a volume basis, 58/60ths is just two customers that
2 happen to be out on the Vancouver Island transmission
3 side of things.
4 MR. BYSTROM: Just to be fair to -- the witness is here
5 -- if you can just ask one question at a time. I've
6 now forgotten what the first one was, and I'm sure
7 it's a little hard for them to keep up with that
8 length of a dialogue. So if you could just ask one
9 question at a time.
10 MR. MARTISKAINEN: So again, back to postage stamp
11 rating. There is no idea about postage stamp for
12 transmission customers only?
13 MR. GOSSELIN: The characteristics we looked at when
14 thinking about the customer groupings were the usage
15 of the system, or the usage of the gas, be it
16 industrial-type customers, fairly large loads — not
17 particularly where they were on the system. Again,
18 following amalgamation and postage stamping
19 principles.
20 MR. MARTISKAINEN: And by "where", you mean physically?
21 Or where high pressure, low pressure, intermediate
22 pressure transmission?
23 MR. GOSSELIN: Where physically.
24 MR. MARTISKAINEN: Would that be typical of other
25 jurisdictions where you have high volume
26 transportation customers and high pressure? Are they

1 paying for distribution costs in their COSAs?
2 It's a question for FEI or Elenchus.
3 **Proceeding Time 2:33 p.m. T57**
4 MR. TODD: The question comes down to how you define your
5 rate classes. And there are, you know, for example,
6 when a natural gas-fired electricity generation
7 station was built in downtown Toronto, Enbridge Gas
8 Distribution did not have a rate that was specific to
9 that kind of volume, and Mike and I recommended the
10 creation of a new class, which was sort of a super
11 high volume. And part of the criteria was that with
12 that level of volume, the customer could only be
13 served -- you know, its needs could only be met — I
14 forget — with 12-inch pipe, or 10-inch pipe.
15 And the class had lots of other customers
16 who could be served with 4-inch pipe. Therefore, the
17 issue was, should the people who cannot be served with
18 the assets that were in that class be paying a share
19 of those costs? The board decided that it was
20 appropriate to separate them, so that people were
21 paying costs of the facilities not literally that they
22 used, right? Because that's where it comes down to a
23 locational thing. You don't want to charge somebody
24 who potentially is using distribution assets, but
25 happens to be in a location where they are not and
26 somebody else very much like them is using

distribution assets, but you may want to consider picking different classes if there is customers who cannot be served at distribution pressures. Okay?

So I think it's what the company was saying, was, "We're not lot at where they're located, we're looking at how they're served." And I would refine that to say, in a sense, how they can be served, right? And you don't want to differentiate customers by how they're served because of location, but how they're served because of what their requirements are. Is that --

MR. MARTISKAINEN: Yeah, again, so that would be similar to high/low pressure or high or low voltage in the case of electricity. So it's not necessarily where you are but high and low voltage have different rates, and structures, and --

MR. TODD: It's what you need. And it's the same in electricity.

MR. MARTISKAINEN: Same thing in gas. So in this case --

MR. TODD: So if somebody has to be served with high voltage --

MR. MARTISKAINEN: That's the question.

MR. TODD: Now, you do get into issues there of customer-owned transformation versus utility-owned transformation. So, you know, we're doing a very simplified version of it right here. But my point

1 was, this becomes what we call classification, how we
2 structure our rate classes and it's not really a cost
3 allocation issue, because the way you structure rate
4 classes then has an effect on the way you do cost
5 allocation.
6 MR. MARTISKAINEN: Correct.
7 MS. TABONE: Can I also add something? We did a survey
8 of what different people did with respect to both
9 transmission and distribution in the EES report, and
10 not every utility has a similar breakdown between
11 transmission and distribution. They all define it
12 differently. They all have different treatments. So,
13 quite often the utilities that we looked at didn't
14 have their own transmission. What they referred to as
15 transmission was all the upstream wholesale
16 transportation. That's what they considered
17 transmission. So they would put all of their mains as
18 distribution.
19 And in some of the cases, then, they would
20 further separate out their distribution mains by size,
21 and some would go to everybody, you know, based on a
22 minimum system, or in some cases an average and excess
23 method, and in some cases they did look at small sizes
24 like two-inch, four-inch, six-inch went to small
25 users, and then the bigger ones only went to the large
26 users. So there's not a consistent treatment across

1 all utilities. There is not a standard practice. And
2 it's very situational to each particular utility and
3 how they use that system.
4 **Proceeding Time 2:37 p.m. T58**
5 MR. MARTISKAINEN: Okay, yeah, correct, and I think just
6 the point we're trying to make is that if you look at
7 the history within this province, within utilities
8 with gas on Vancouver Island, historically the
9 distribution costs have not been allocated to certain
10 companies. The proposal is to change all of that, and
11 add a lot to their cost allocation, but not doing that
12 for everyone, just for essentially two customers.
13 That would be again, not a jurisdictional difference,
14 just a difference in the history, and at this point in
15 time there is a proposal to change all of that
16 history, but only for a couple of customers.
17 MR. HODGINS: I was going to say to clarify, the
18 facilities and the high-pressure facilities. I think
19 there is a bit of confusion. We basically have
20 transmission pressure gas showing up to the facility,
21 but we are stepping it down and providing to the mills
22 distribution pressure. So, it is the same pressure.
23 So, near the mills we'll also be stepping it down to
24 distribution pressure. So, the community around you,
25 be it a stone's throw away -- so, this goes back to
26 what Dave was saying about different customers use

1 different sections of pipe, different -- so it is just
2 getting into those different buckets, right? So.
3 THE CHAIRPERSON: Does FEI have any questions of
4 Elenchus?
5 MR. PERTTULA: At several points in relation to that
6 table of the range of reasonableness of other gas
7 utilities, you made reference to differential rate
8 increases, and that is in some of the IR responses,
9 and I think in your report as well. Can you explain
10 maybe a bit of the context of what you mean by
11 "differential rate increases"? Because I think the
12 context, as I understand it, is one where utilities
13 have a rate case that encompasses both revenue
14 requirement and rate design, and they're back-to-back,
15 right? So people have just gone through the revenue
16 requirement portion of it, and that establishes the
17 general rate increase, and then the rate design and
18 cost allocation portion is where this differential
19 rate increase concept comes from? Is that a
20 reasonable characterization of that concept?
21 MR. TODD: Yes, most typically where we're involved in
22 cost allocation studies, it is a phase within a
23 general rate application. And so there ends up being
24 an approved revenue requirement, then there is an
25 approved cost of service methodology. The approved
26 revenue requirement is then run through that approved

1 methodology, to come up with revenue cost ratios and
2 often that bringing the pieces together is actually a
3 separate stage. Then after the hearing, because you
4 have to wait until the Commission's decision is out.
5 And then there is a subsequent kind of a mini-process,
6 for actually establishing rates within the range on
7 that basis.
8 In other cases, such as right now, we're
9 involved in cost of service proceeding with New
10 Brunswick power. It is a methodological proceeding.
11 Whatever comes out of that process will have no impact
12 on rates. It is essentially determining methodology
13 that will then get used as a model which is run
14 through, you know, so that the next general rate
15 application, the revenue requirement numbers will be
16 run through that model to produce results. And those
17 revenue-to-cost ratio results would also then be used
18 to help set rates out of the GRA.
19 MR. PERTTULA: And so just in follow up, would you expect
20 or suggest that interveners and intervener groups are
21 very alive to those differential rate increases
22 because of the way it's been sort of stacked onto the
23 end of the revenue requirement proceedings.
24 **Proceeding Time 2:42 p.m. T59**
25 MR. TODD: Well, I think they're always sensitive to "I'm
26 getting a rate increase that somebody else isn't

1 getting," or "I'm getting a bigger one." Whether it's
2 stacked on top, or whether it's an adjustment to
3 rates, there is always a sensitivity to "I'm being, in
4 effect, treated differently than others." No matter
5 when it is.
6 I mean, the complexity is, if you're in a
7 performance-based regulation regime, where you're not
8 doing a full cost-of-service review as well and you
9 are making rate adjustments, you've got the additional
10 complexity that you're not applying the model to an
11 immediately then approved revenue requirement.
12 MR. PERTTULA: Thank you.
13 MS. TABONE: Yeah, I have a question also about Table 4
14 and the range of reasonableness. In some of these
15 cases I know that they only have three or four
16 different rate classes, whereas FortisBC, I'm not sure
17 if it's eight or ten. Would you say the range of
18 reasonableness would depend somewhat on how many
19 different customer classes you're considering?
20 MR. TODD: Potentially -- well, there's a number of
21 factors come into play. I mean, yes, if you have -- I
22 would think more in terms of diversity. Because the
23 diversity within your customer, if you have customer
24 classes where you're serving very different kinds of
25 customers, or I think for Fortis Energy, serving parts
26 of the province that are very different that creates

1 greater risk of inequity, shall we say, within a class
2 and, you know, potentially could make it hard to
3 justify differential rate treatment. Be an adjustment
4 where some are up and down, or be it with the GRA of
5 moving people up by different amounts.
6 MS. TABONE: Okay, thanks.
7 THE CHAIRPERSON: Any other questions?
8 Commissioners? Our questions have been
9 answered. So, thank you all for participating in this
10 streamlined review process. The next step on the
11 regulatory timetable is written arguments from FEI on
12 the COSA and revenue to cost ratios. Thank you.
13 (PROCEEDINGS ADJOURNED AT 2:45 P.M.)
14
15 I HEREBY CERTIFY THAT THE FORGOING
is a true and accurate transcript of
the recording provided to me, to the
16 best of my skill and ability.
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19 D.A. Bemister, Court Reporter
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September 12, 2017
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