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.
March 9th, 2017

WORKSHOP 2:
COSA & RATE DESIGN PROPOSALS

BEFORE:

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

VOLUME 2

Allwest Reporting Ltd.
#1200 - 1125 Howe Street
Vancouver, B.C. V6Z 2K8

FortisBC Energy Inc.

Workshop 2: COSA & Rate Design Proposals

March 9th, 2017

(PROCEEDINGS COMMENCED AT 9:01 A.M.)

THE CHAIRPERSON: Good morning. My name is Karen Keilty and I am the Panel Chair for review of the FortisBC Energy Inc., or FEI's, 2016 rate design application. With me today are Commissioners Doug Enns and Bill Everett.

By Order G-6-17 the Commission established a regulatory timetable for this proceeding. I'd like to welcome everyone to the second of two workshops included in the regulatory timetable. This workshop will include a review of the cost of service allocation, or COSA models; the proposals in the application and the February 2nd, 2017 supplementary filing; and the approvals sought.

The workshop will form part of the evidentiary record for the proceeding and it will be transcribed. The presentation materials will be posted as evidence.

After I have completed my remarks, I will be turning the workshop over to FEI to take us through its presentation. I expect FEI will allow us to ask questions for clarity during the presentation, and at the end of the presentation there will also be an

1 opportunity for questions. Please note, the Panel
2 members may ask questions of FEI and/or other parties
3 in this workshop.
4 We expect the workshop to end around 4:00
5 p.m., and we will take a break in the morning and the
6 afternoon, and we'll be breaking for lunch. I'll ask
7 FEI's presenters to decide on the appropriate time for
8 the breaks based on the flow of their presentation.
9 During the workshop, it is necessary to
10 have the microphone while speaking in order to
11 facilitate the transcription process and so that
12 participants on the phone can hear clearly. We also
13 ask that you state your name prior to speaking.
14 Now I will go around the room and have
15 people introduce themselves, and who they represent,
16 followed by any participants who have joined us on the
17 phone. Thank you, and we can pass the mike for
18 introductions.
19 MR. BYSTROM: Chris Bystrom with the law firm Fasken
20 Martineau representing FortisBC Energy Inc.
21 MR. PERTTULA: Dave Pertulla, FortisBC Energy Inc.,
22 Regulatory Affairs.
23 MS. SALBACH: Stephanie Salbach, FortisBC, Transportation
24 Services Manager.
25 MS. GRAVEL: Colleen Gravel, FortisBC, Regulatory
26 Affairs.

1 MS. JOLY: Janice Joly, FortisBC Regulatory Affairs.
2 MR. MOORE: Ed Moore, FortisBC Regulatory Affairs.
3 MR. AMEN: Ron Amen, Black & Veatch Management
4 Consulting, representing FortisBC.
5 MR. MASON: Matt Mason, FortisBC, External Relations.
6 MS. FALCON: Anne Falcon, EES Consulting, representing
7 FEI.
8 MS. ROY: Diane Roy, FortisBC, Regulatory Affairs.
9 MS. LANG: Mary Lang, FortisBC Energy Supply.
10 MR. MORROW: Kirby Morrow, Absolute Energy.
11 MS. JOBS: Susan Jobs, Absolute Energy.
12 MS. McCORDIC: Mary McCordic, Shell Energy.
13 MR. HODGINS: Kevin Hodgins, FortisBC, Industrial
14 Accounts.
15 MR. OTTO: Verlon Otto, Pacific Northern Gas.
16 MS. BRAITHWAITE: Tannis Braithwaite, with the B.C.
17 Public Interest Advocacy Centre.
18 MR. CRAIG: David Craig, the Commercial Energy Consumers
19 ratepayer group.
20 MR. WEAFER: Chris Weafer, from the law firm Owen, Bird,
21 representing the Commercial Energy Consumers.
22 MR. HASTINGS: Calvin Hastings, BC Hydro, Regulatory and
23 Rates Group.
24 MS. TRESOGLAVIC: Marjia Tresoglavic, BCUC.
25 MS. SUE: Suzanne Sue, BCUC.
26 MR. HACKNEY: Tom Hackney, B.C. Sustainable Energy

1 Association and Sierra Club B.C.
2 MR. ANDREWS: Bill Andrews, I'm counsel for the B.C.
3 Sustainable Energy Association and Sierra Club B.C.
4 MR. MILLER: Paul Miller, Boughton Law Corporation,
5 Commission counsel.
6 MR. SOUTH: Errol South, BCUC.
7 MR. BURSEY: Hi. Dave Bursey, the guy at the back. I'm
8 with Industrial Consumers Group. That's Teck, Domtar,
9 Weyerhaeuser and Celgar. Thank you.
10 MR. GOSSELIN: Richard Gosselin, FortisBC, Regulatory
11 Affairs.
12 MR. TOKY: Atul Toky, FortisBC, Regulatory Affairs.
13 MR. MEHRAZMA: Rouzbeh Mehrazma, FEI, Regulatory Affairs.
14 THE CHAIRPERSON: Is there anyone on the phone who would
15 like to introduce themselves?
16 MS. DAVIDSON: Jennifer Davidson, B.C. Government.
17 THE CHAIRPERSON: Thank you. Okay. I will turn it over
18 to FEI.
19 MR. PERTTULA: Thank you, Commissioners and participants,
20 for giving us the opportunity to present our rate
21 design application today.
22 As Commissioner Keilty mentioned, we are
23 reviewing the cost of service allocation models, the
24 rate design proposals in the application, and the
25 approvals sought.
26 **Proceeding Time 9:08 a.m. T02**

And so just as a bit of an introduction, we thought we'd look at a couple of slides from last week's presentation — there we go — just to set some of the background.

And so as we heard last week, this slide depicts the two major rate-setting applications that the Commission deals with for public utilities: revenue requirements applications and rate design applications. And it's obvious the Commission reviews lots of other types of applications, like capital projects or energy supply contract applications or resource plans. But these two applications that are depicted here are the two major ones in the context of rate setting.

So the pie on the left-hand side of the slide is representative of the revenue requirement, and the revenue requirement is the revenues that must be collected from our customers to recover the overall costs of providing service. And you'll see that there are different components in the overall revenue requirement. There's a commodity slice; there's a midstream slice, also called storage and transport; and there's the multi-coloured slices which deal with the utility's delivery cost of service. And so those are the major components in our delivery cost of service.

1 So that's a revenue requirement and we've
2 characterized that with the question: "How big is the
3 pie?"
4 And the moving over to the two pies on the
5 right-hand side of the screen -- did I say the wrong
6 side of the screen for the first one? Anyway, left
7 for revenue requirement, right for cost allocation and
8 rate design.
9 So cost allocation is taking the various
10 costs and allocating them to the different customer
11 classes or customer groups. And so you see what we've
12 got there are the allocations, for example, to the
13 residential class are all in a light blue colour, the
14 allocations to the small and large commercial class
15 are in the yellow, and the allocations to the
16 industrials are in the green colouring there.
17 So we'll get into the details on the cost
18 allocation process, but the next step is how do you
19 collect those costs, and that's the process of rate
20 design.
21 **Proceeding Time 9:11 a.m. T03**
22 And so we've taken as an example there, the
23 residential class, and so the two main charges that we
24 use for collecting our residential revenue is a basic
25 charge and a delivery charge. But there are other
26 types of charges in the other rate classes.

1 So cost allocation is how do you slice the
2 pie and then rate design is how do you pay for the
3 slice.
4 The next slide here is a depiction of the
5 overall value chain for natural gas, and it goes all
6 the way from the commodity portion at the gas
7 wellhead, through gas processing, through upstream
8 transmission as well as storage resources. Then
9 there's a nice arch there which is representative of
10 the interconnect. In some jurisdictions they refer to
11 it as the city the gate. But that's the interconnect
12 between the upstream pipeline. On the line -- we've
13 lost our presentation momentarily. But it's back.
14 And then below that interconnect is the
15 utility's distribution system where we deliver the gas
16 to large-volume customers, commercial customers and
17 residential customers.
18 And as we talked about last week, there are
19 three main business models -- or service models that
20 FEI provides natural gas to its customers. So two of
21 them we were referring to as sales service, and we
22 have the bundled sales service where customers receive
23 the commodity, the midstream or storage and
24 transportation and the delivery service all from FEI.
25 Then the unbundled sales service where customers
26 receive their commodity from a Customer Choice

1 marketer, but they still receive the storage and
2 transport and delivery portions from FEI.
3 And then the third business model is
4 transportation service, where the customers arrange to
5 get the commodity to the interconnect with FEI or with
6 the utility. So they've done whatever is necessary to
7 secure the commodity, as well as whatever storage and
8 transportation arrangements are needed to get the
9 commodity there, and then all that they get from FEI
10 is the delivery service across the utility system.
11 **Proceeding Time 9:15 a.m. T4**
12 And so we talked also about how our bills
13 reflect these three different components, commodity
14 component and the storage and transport for midstream,
15 as well as the delivery component. So customers see
16 all those things on their bill, excepting the
17 transportation customers who only see the delivery
18 charges.
19 And then we talked about the different
20 types of costs that are represented. Some of them are
21 volumetric or energy related. Some of them are
22 related to demand or capacity. And some costs are
23 driven by the fact that we have customers on the
24 system.
25 And then finally we have our tariffs and
26 terms and conditions which set out all the rates and

also the terms and conditions of providing service to customers.

Something we didn't cover last week but which I'll do a brief background on is the rate design history, so for FEI. So this slide here doesn't cover all the different components in the rate design history but it kind of covers the major ones. So back in 1991 and 1993 we had our first two rate design proceedings for BC Gas as FEI was known at the time, so that the 1991 or Phase A rate design proceeding established the practice of allocating commodity-related costs on an energy or volumetric basis and demand charges and other fixed costs pertaining to gas supply operations on a load factor adjusted basis. And then shortly after that our Phase B rate design proceeding in 1993 approved common delivery rates for the Lower Mainland, Inland and Columbia service areas. And when the tariff was established following that proceeding, it set out the different charges, the commodity-related charges and the delivery-related charges, separately in the tariff document.

In 1996 there was another rate design proceeding which went through a negotiated settlement process. So the postage stamp methodology from the Phase B rate design was maintained. There were some increases to basic charges for the residential and

1 commercial classes. For our small industrial or
2 general service classes Rates 5 and 25 a demand charge
3 formula was introduced, as well as a deemed load
4 factor of 50 percent for gas costs. And then that was
5 when we had the large commercial service,
6 transportation service introduced. That's Rate
7 Schedule 23.
8 A next major point was in 2000 and 2001 we
9 had built the Southern Crossing Pipeline, which was a
10 large capital project being added to the rate base.
11 And so through two processes through 2000 and --
12 sorry, the 2000 SCP cost allocation process and the
13 2001 rate design, we had arrangements were approved
14 whereby the cost of service of the Southern Crossing
15 Pipeline was allocated to non-bypass customers in the
16 normal fashion, based on an equal percentage of
17 delivery margin. Except that it was not allocated to
18 either the bypass customers or Columbia, rate schedule
19 22B customers.
20 **Proceeding Time 9:19 a.m. T05**
21 And the 2001 rate design accepted that cost
22 allocation as a starting point. Also, every --
23 several other rate design changes came about through
24 that, which was a negotiated settlement process as
25 well, approved by the Commission.
26 Next major point was in 2004 and 2007, when

we had commodity unbundling, or the Customer Choice program, as we referred to it, this followed some provincial energy policy that was -- came from 2002. And these processes provided the opportunity for marketers to sell gas to small volume customers. And so in 2004, that was implemented for the commercial rate classes. And in 2007, the residential rate classes were -- rate class, sorry, was introduced to the Customer Choice program.

And so this is when what was -- we were referring to last week as the "essential service model" was established. And the gas supply costs which had formerly been in one big bucket were separated into two portfolios, the commodity and the midstream, or storage and transport as we now refer to it.

And then the last item on the list there is the 2012 common rates amalgamation and rate design and the 2013 reconsideration of that. And so the application there was for FEI to amalgamate three utilities — which were FEI, which at that time was the Mainland and Interior; FEVI, or the Vancouver Island operation; and FEW, or FortisBC Energy (Whistler) — into a single entity and implement common rates. And so -- or postage-stamp rates.

And so this application was approved in the

1 reconsideration process, and allowing postage-stamp
2 rates with a three-year phase-in period.
3 And 2017, that we're in right now, is the
4 last of the years in that phase-in period. So,
5 beginning with 2018, we'll move into postage-stamp
6 rates across those three service areas.
7 So that's a bit of a historical picture.
8 And we'll just look briefly at the agenda for today.
9 And the main part is in the morning we'll be dealing
10 with the COSA methodology and -- the cost of service
11 allocation methodology, that is. And various related
12 information and studies that have been involved in
13 preparing the COSA studies. And I guess we'll see how
14 far we get along, and we may get to the beginning of
15 the rate design proposals in the morning. But we'll
16 see how it goes.
17 And so the different rate design proposals
18 may happen in the afternoon, or perhaps starting later
19 in the morning, and then finally we'll be dealing with
20 the next steps in the regulatory timetable. So,
21 that's a snapshot of the agenda there.
22 And our speakers today are several that
23 presented last week, but we have, I believe, two new
24 speakers that didn't present last week and that's
25 Rouzbeh Mehrazma and Kevin Hodgins. But I'll just ask
26 them to introduce themselves when they come up.

Proceeding Time 9:24 a.m. T06

And so we can move now into the presentation on the COSA results and methodology, and so I would invite Rick Gosselin to come up and do that.

MR. GOSSELIN: Thank you, Dave. Welcome and thank you Commissioners and participants. Today I'll be covering most -- I'll be covering the cost allocations for FEI and Fort Nelson. My name is Richard Gosselin, I'm the manager of cost of service for FortisBC.

Cost allocation is a fundamental component in the process of developing our rate design application. FEI performed its cost allocations in accordance with standard utility practice. Cost allocation is subjective in some cases. Some costs can be allocated in more than one way. FEI has relied upon its past practices, system knowledge, judgment and logic to make its cost allocation decisions.

Cost allocation results inform us about the cost causation and the reasonableness of the revenue that we collect from our rate schedules. There are many mathematical calculations and complex relationships in the cost of service model that we use, and I'll do my best to answer as many questions as you have. However, if they are questions that are too complex in nature, I may have to suggest that we

1 pose those through the IR process, just because some
2 of those calculations are quite inter-related in the
3 COSA model.
4 First, I'd like to take you through the
5 steps of the cost allocation process. You've seen
6 this last week, but I just wanted to run through it
7 quickly to reiterate the process that we go through
8 when we do our cost allocations. First we start with
9 our cost of service, of course, the revenue
10 requirement. And the first thing we do within the
11 COSA model is we functionalize the cost of service.
12 We functualize both the plant rate base and the cost
13 of service, but the functualization process puts the
14 costs into buckets that define the service that they
15 are in support of.
16 The second thing we do in the cost
17 allocation process is we classify the costs. So of
18 the costs within the function, are they energy
19 related? Meaning do they vary with energy? Are they
20 caused by us delivering energy? Are they demand
21 related? Are the costs there because the customers or
22 the customer group incurs a certain demand at a
23 certain time? Or are the costs there because they
24 joined the system, because they're a customer?
25 So that's the cost causation piece of it,
26 or the classification.

Then ultimately we allocate the costs from the classifications based on the contributor to the allocator. So in other words, if we are allocating a customer cost based on number of customers, we would use the number of customers in the rate schedule to allocate those costs.

To do this, we have a couple of supporting studies that we'll talk through the results of as well, that help us in our cost allocations and in some cases classification.

Some of you may remember this slide from last week: What is cost allocation? And for those on the phone it's slide number 8.

On the left we have -- sorry. On the customer's bill we see commodity cost, storage and transport cost and delivery charges, and the delivery charges are the delivery cost can include things like the basic charge or a demand charge or a volumetric delivery rate.

FEI has a separate process to calculate and allocate each of these components. The commodity cost charges that you see on the left-hand side there, and the storage and transport charges are refreshed quarterly, and FEI seeks approval for the commodity costs quarterly and the storage and transport charges annually.

1 So in a separate process FEI comes to the
2 Commission and applies for changes in the commodity
3 cost and the storage cost.
4 The third component, the delivery cost are
5 reviewed annually in FEI's revenue requirement as Dave
6 spoke to earlier. So the revenue requirement requests
7 basically the revenue required to serve its customers
8 and we call those the delivery costs. And we review
9 them in either a revenue requirement or an annual
10 review for FEI right now, while we're under PBR.
11 **Proceeding Time 9:29 a.m. T07**
12 So when we talk about cost allocation, cost
13 of service allocation in the rate design application,
14 unless otherwise specified, we're really talking about
15 the delivery cost allocation. So in the next hour,
16 hour and a half or so, I will be speaking to the
17 delivery cost allocation for both FEI and Fort Nelson.
18 Slide 9. COSA model, cost and revenue
19 assumptions. So, we start with our test year. That
20 was the far left-hand box, the revenue requirement or
21 the cost of service. The test year is simply FEI's
22 forecast of costs and revenues approved by the
23 Commission through the annual review for rates for
24 2016. So the FEI COSA model starts with a test year
25 that is simply 2016's approved costs and revenues.
26 Some *pro forma* adjustments need to be made

1 to the test year delivery costs that we'll cover in
2 the next few slides.
3 So, as I just mentioned, we have
4 adjustments to the test year. These adjustments
5 impact the cost of service or the revenue requirement
6 at the beginning of the cost allocation process. So,
7 the process right at the front there, the cost of
8 service revenue requirement, the adjustments to the
9 test year basically affect that part of the component
10 of the cost allocation process.
11 So how do the adjustments to the test year
12 affect the COSA model? This is slide 11, for those on
13 the phone.
14 Well, when we bring in the test year, the
15 2016 annual review, into the COSA model, our revenues
16 equal our costs. This is the approved test year,
17 where we've been approved a certain rate change. And
18 in that model, or in that input, in the COSA model,
19 the revenues equal the costs.
20 Then we make these adjustments to the test
21 year. Typically these adjustments create a mismatch
22 between costs and revenues. So the difference between
23 the costs and the revenue is applied to all rate
24 schedules as a change in the revenue required. So we
25 apply the same percentage change to all our rate
26 schedules. So if the adjustments to the test year,

1 let's say, increase the cost of service by 2 percent,
2 we'll increase everyone's delivery cost of service,
3 all the non-bypass customers' delivery cost of service
4 in the COSA model by 2 percent, so now the revenues
5 equal the costs again. And then we go on to the
6 second process of functionalization, and basically
7 allocating the rest of our costs based on the revenue
8 equaling the cost.
9 The adjustments we made to the test year.
10 Basically the adjustments are made so the COSA
11 reflects what the utility is going to look like in the
12 near term. The adjustments we've made are the test
13 year O&M, was split into an activity view. So the
14 amount that we brought in from the revenue requirement
15 was a gross amount, based on the PBR, but we split
16 that up into its activity view, so we can properly
17 functionalize those costs.
18 There was a change in the RS 22A volume
19 that we'll speak to in a minute, that we made in the
20 COSA as well. We have some adjustments on contract
21 revenue for BC Hydro, Island Generation and Burrard
22 Thermal. We have some larger capital projects coming
23 in, the Lower Mainland intermediate pipe system
24 upgrade project, or LMIPSU, for an acronym, that we
25 brought into the COSA model. We have the Coastal
26 transmission system upgrades that we expect to be in

service, and the acronym for that is CTS, and we brought those into the COSA model as well.

And finally we have added in the Tilbury expansion project that's undergoing right now, and we brought that into the COSA model as well.

In the next few slides, we'll talk through all of these adjustments and how they were brought in and their impact.

Proceeding Time 9:34 a.m. T08

As I mentioned under FEI's current PBR, the O&M test year is basically a single amount. For a proper cost allocation, we'd like to -- we needed to split that O&M amount into its various components so they can be properly functionalized and allocated to all the rate schedules we have in the COSA model. We used our 2015 actuals, so we looked at our 2015 actuals O&M, and the activity in view of our 2015 actuals, and we used that to split up the 2016 O&M that was included in the revenue requirement of the test year. The resulting table that you see in the slide, Slide 13 for those on the phone, is the summary of all the splits that we made, and you can also find that in the application Appendix 6-3 in a little bit more detail.

So as you can see, Distribution picked up 56.4 million of the total 271.6 million in O&M.

The next adjustment we made was for our 22A volume adjustment. We adjusted the COSA for Rate Schedule 22A volume -- or revenue that was incorrectly classified in our 2016 annual review between firm and interruptible. The result was really a net decrease in revenue of 1.3 million. So we reduced the revenue in the COSA from 22A by a net 1.3 million. And we also increased the firm volume in TJs per day for Rate Schedule 22A in the COSA for cost allocation purposes.

Sorry, can you repeat that?

MR. BURSEY: Does that explain why the revenue-to-cost ratio changed so much from the material presented in the workshop --

MR. GOSSELIN: Last summer?

MR. BURSEY: Yeah, to now?

MR. GOSSELIN: That does explain it, yes. So the increase in the firm demand, which is the demand that we have contracted with these folks, what it does it attracted more costs.

MR. BURSEY: Right.

MR. GOSSELIN: And also on the revenue side, we overstated the revenue because the interruptible charges for these folks are a little bit higher than the firm charges. So those two things together was the reason why -- the errors that were embedded in the 2016 revenue requirement was the reason that RS 22A

was so high on the RC ratio.

MR. BURSEY: Okay, thank you.

MR. GOSSELIN: Yeah. Contract revenue adjustment in the test year that we made in the COSA. So we adjusted the COSA for revenue and volume changes for two of our contracts that were effective November 2016. So in November 2016 BC Hydro Island Generation increased its firm volume and its rate. The firm volume went up by 5 TJs per day and the rate went up by 10 cents per gigajoule. And in November 2016 our Burrard Thermal Agreement expired. So what we did was we tried to make 2016 look like going forward years and so we adjusted the volume and the revenue for both of these customers, assuming that it happened like this all year.

The two larger capital projects that we had included in the COSA or that we have included in the COSA, the LMIPSU and the CTS, Slide 16, the capital costs included in the COSA in plant is $426 million, and the annual cost is -- the risks for these two items, or these two projects, rather, is about $39 million, and those two costs were included in the COSA. These projects are forecast to be completed in 2018.

Proceeding Time 9:34 a.m. T09

Slide 17, Tilbury expansion project. The

Tilbury expansion projects expected to be completed in 2017. We directly assign the costs in revenue to rate schedule 46 in the COSA. As we discussed last year, we used the ten-year levelized net cost of revenue, which equals about a 7 million net difference. The 7 million net difference between costs and revenues has been allocated to all other customers in the COSA.

Moving on to slide 18, so in the COSA we have a couple of supporting studies that we use to help us classify costs and allocate costs. The names of the supporting studies are the minimum system study, sometimes referred to as the MSS, and in addition to the MSS we have another component that is part of that. It is called the peak load carrying capacity adjustment, PLCC adjustment. Those two together help us classify the distribution plant into customer and demand, and we'll see how that works in a bit.

And we also have a customer weighting factor that helps us classify our services in meters and also our administration and billing costs. Rather, not help us classify but rather help us allocate a fair amount to each rate schedule using the customer weighting factor studies. And I'll show you how those ones -- the calculation for those and the results.

Motoring along here. Slide 19, the minimum system study. The minimum system study is applied to components of FEI's distribution system. The MSS approaches recognized that the distribution is in place in part to connect our customers to the system and in part to serve our customers some level of peak demand when they need it.

The portion of FEI's distribution system required to connect the customers classified in the COSA as customer related and the balance is classified as demand related. The MSS calculates these proportions. So we have about 25,000 kilometres of distribution mains in polyethylene and steel in the province. Our minimum standard is 60 millimetre PE.

So what we do is we essentially value the entire 25,000 kilometres of our distribution mains, regardless of their size, at the value of the 60 millimetre polyethylene pipe. That value, when you do that, turns out to be $1.419 billion. So when you value the distribution system at our minimum standard, it sums to 1.419 billion.

Then you look at the value of the distribution system at its actual value, at the weighted actual cost -- or the weighted cost of replacement, rather. And when you do that, you get a value of $4.7 billion. So the value of the

1 distribution system out there today is about $4.7
2 billion.
3 The minimum system says, well, if we only
4 built a minimum system it would have been for 1.4
5 billion, divided by the 4.7 billion equals 30 percent.
6 So 30 percent of the distribution mains cost is
7 classified as customer related.
8 This is how we use the minimum system to
9 take the distribution mains and split it into customer
10 and demand. 30 percent is classified as customer, and
11 then the offset of 70 percent is classified as demand.
12 The PLCC adjustment. The minimum system
13 study calculates the proportion of FEI's distribution
14 system that is customer-related, using the value of
15 the 60 millimetre PE pipe.
16 **Proceeding Time 9:39 a.m. T10**
17 While the 60 millimetre PE pipe also has a
18 carrying capacity -- a load-carrying capacity,
19 basically there is a load or a capacity component
20 embedded in the 60 millimetre pipe. The peak load
21 carrying capacity adjustment is an adjustment that
22 recognizes there is a load carrying capacity embedded
23 in the minimum system, and attempts to avoid double-
24 counting that load. The PLCC adjustment is used to
25 reduce the peak day demand allocator that we use to
26 allocate demand-related costs. This is done so that

we're not over-allocating demand-related costs, because there is already some demand-related costs existing in the minimum system.

So the PLCC is adjustment that we use to recognize that the minimum system of 30 percent that's being allocated on customer already has some demand component embedded in it. So the PLCC adjusts the peak day demand so we're not basically double-allocating demand.

So, the result, as you can find in Appendix 6-5, equals .25 gigajoules per day per customer when you do all the math on the PLCC adjustment. So an example at the bottom of the slide shows you how we actually use it in the COSA to reduce peak day demand so we don't double-allocate demand. So at .25 gigajoules per day per customer for rate schedule 1, times about 886,000 customers, it equals to 182 TJs per day.

RS 1's peak day demand, in the COSA model, is 636 TJs per day. So what we do is, we take the 636, we subtract 182, and we use 453 TJs per day of peak day demand to allocate the distribution plant to these RS 1 customers, rate schedule 1 customers. And we do that for all the rate schedules in the COSA when allocating distribution plant.

Moving on to slide 21, we have the customer

weighting factor study. This recognizes that not all customers cost the same to connect to FEI's system. Nor do they cost the same to administer. Higher volume customers tend to cost more to connect, with larger meters and larger services, and those same customers tend to cost more to administer and bill.

The weighting factor for meters and services, it's used to weight the number of customers in a rate schedule for allocation of distribution meters and services. The weighting is relative to rate schedule 1. So rate schedule 1 is always equal to 1.0, and then you look at the costs of the meters and services for all the rate schedules in relation to rate schedule 1, and you develop a proportionate factor.

So, rate schedule 2, in the next little table in the middle of the page, their meters and services cost 1.7 times that of rate schedule 1. So what we do in the COSA model, when we allocate costs for meters and services, rate schedule 2 we would increase their number of customers by 1.7. So we take the number of customers, we times by 1.7, and that weighted customer is -- that weighted customer number is the number we use to allocate meters and services costs.

And we'll go through some examples in a

1 little bit, with real numbers from the COSA, to show
2 you how it works.
3 The RS 22 one that's asterisked there, RS
4 22 firm factor is actually a blend of our existing
5 large industrial customers, that would fall into RS 22
6 as discussed in the application section under our
7 industrial proposals. We'll get to the industrial
8 proposals later today, but I just wanted to make you
9 aware that the 1400 was basically a blend of some of
10 the industrial customers that we have.
11 **Proceeding Time 9:49 a.m. T11**
12 So the weighting factor for administration
13 and billing, same approach, same idea. It's a number
14 that use to scale our customers up when allocating
15 administration and billing costs, recognizing that
16 some of our larger customers cost more to administer
17 and bill than the smaller customers. In this example,
18 RS 1 is 1.0 and same for 2, but the large commercial
19 customers cost about 1.2 times the amount that an RS 1
20 customer would. And again, we'll get to some examples
21 and some real numbers from the COSA shortly that
22 demonstrates how we use these.
23 The next process in the COSA -- the next
24 step in the COSA rather is the functionalization,
25 classification, allocation. So we're going to talk
26 through some of the examples of this. We won't do

each one separately, we look at them on a whole because it's easier to see how it all works in the COSA when you look at all three steps together.

Yes. So next one. So because much of FEI's delivery cost of service exist to serve the plant assets, FEI must first allocate it's plant and rate base costs. Some of the cost allocated based on plant and rate base include things like distribution O&M, general and intangible O&M, property taxes, income taxes, earned return. Those are just some of the costs in the delivery cost of service that we use plant and rate base to allocate.

So this pie basically shows you our rate base categorized into its different categories. You can look in the revenue requirement and you'll get this kind of picture. We have $4.5 billion in our rate base. A quarter of that is in transmission plant. About half of it is in distribution plant. Storage makes up for about an eighth of it. General intangibles, again, another eighth and then a few smaller items like working capital and unamortized deferrals make up the balance of our $4.5 billion in rate base.

The following slides I'm going to show you show the allocations of some of these rate base items. The items -- the examples that we are going to go

through include distribution mains, and we are going to see how we applied the minimum system study results. We're also going to show how we applied the peak load carrying capacity adjustment.

We're also going to look at distribution service lines and meters and we're going to show you how we applied the weighting factor for service lines and meters, and then we're going to go to a summary of the rate base allocation -- rate base and plant allocations.

For those on the phone, we're on slide 25. So there's lots of numbers and lots of math, but we're going to start at the top and move right through it.

So plant and rate base. This is the account number 475 in the uniform system of accounts there for utilities. It's distribution plant mains. The amount of net plant that we have is $1.1 billion, and we functionalize it as distribution. These distribution mains, they serve the distribution function. This is the cost that we say, well, these are the distribution mains. They are in place in part because our customers exist and they are in place in part to serve a peak load demand at a time that our customer needs it.

So this is where we apply the minimum systems study where we split up this cost into its

1 demand and customer components using the result of
2 that. And then we allocate it, the demand component
3 in particular, using the adjusted peak day demand and
4 it's adjusted by the peak load carrying capacity. And
5 then we allocate the customer portion based on the
6 average number of customers in that rate schedule.
7 **Proceeding Time 9:54 a.m. T12**
8 So the next table in the middle of the
9 page, you'll see the Minimum System Study results of
10 30 percent customer and 70 percent demand. When you
11 apply that to the 1.1 -- or $1,123.4 million, we get a
12 split of 340,000 classified as customer, and -- sorry,
13 340 million classified as customer, and 783 million
14 classified as demand.
15 So, first of all we're going to allocate
16 the customer portion, the $340 million. On the bottom
17 table on the left-hand side you'll find the rate
18 schedules that were allocated a component of this $340
19 million. You'll see the average number of customers.
20 Those are the customer numbers that you'll find in the
21 revenue requirement or test year. The percentage is
22 simply a derivation of the customer per rate schedule
23 divided by the total customers. So for Rate Schedule
24 1 it'd be 886652 divided by 979047, to get you a 90.6
25 percent allocator. Then we use the 90.6 or the
26 percentages in that percentage column to allocate the

$340 million in customer cost. So of the distribution mains of $1.1 billion, Rate Schedule 1 at this part of the allocation as it attracted $308 million of those costs. That's the customer-related component.

The table at the top or the line at the top and the table in the middle is the same one from the previous slide, but now we're going to talk about how we allocate the demand portion of it. So we're going to talk about how we allocate the 783 million of demand related to the distribution mains. This is Slide number 26 for those on the phone.

So in the table on the bottom you'll see the rate schedules on the left and these are the rate schedules that attracted some of these demand costs. You'll see the peak day demand in the second column. This is the peak day demand that was calculated based on the load factors for our customers. And then you see the PLCC adjustment. So this again recognizing the fact that these rate schedules have already paid for some demand component embedded in the minimum system through their customer allocation. So we take the PLCC adjustment and we reduce the peak day demand that we've calculated in the COSA, and we get an adjusted peak day demand for Rate Schedule 1 of 453.

So when you take the adjusted peak day demand, you calculate -- you use those numbers to

1 derive the percentages. Same way as we did before,
2 453 TJs per day for Rate Schedule 1 divided by a
3 million TJs per day for everybody equals 44.4 percent.
4 So of the $783 million of demand-related
5 costs from those distribution mains, 44 percent of it
6 is allocated to Rate Schedule 1. So Rate Schedule 1
7 attracts $347 million of the demand component, demand-
8 related component of the distribution mains --
9 distribution plant mains.
10 Slide number 27. We're going to talk
11 through the classification and allocation of services
12 and meters, distribution plant services and meters.
13 The account, the uniform account is 473/478. The
14 amount, the net plant amount is $962 million. We
15 functionalized that in the COSA as distribution
16 related, distribution -- sorry, yeah, it's a
17 distribution function. We have classified it as
18 customer. So services, meters -- service lines and
19 meters are there because a customer joined the system.
20 **Proceeding Time 9:58 a.m. T13**
21 There's a piece of pipe in the meter that runs off the
22 main going down the middle of the street. And we
23 allocate those based on average customers, but not
24 just average customers, the average customers adjusted
25 by the customer weighting factor that we've derived to
26 recognize larger customers tend to have more expensive

1 services and meters.
2 So the table down at the bottom, we see a
3 rate schedule on the left again. We see the number of
4 customers in each of those rate schedules, from the
5 test year. And then we have the weighting factor for
6 services and meters that was derived in the customer
7 weighting factor study.
8 So we'll move to rate schedule 2, because
9 rate schedule 1 is the basis, basically, the 1.0
10 proportion.
11 So rate schedule 2 has about 85,000
12 customers in it. Recognizing that rate schedule 2
13 customers services and meters are about 1.7 times more
14 costly than rate schedule 1, we multiply the 84,737 by
15 1.7 to get 146,934 customers -- weighted customers.
16 When you take the 146,934 and you divide it by the
17 total of weighted customers of 1.114 million, down at
18 the bottom, we get an allocation of 13.2 percent for
19 rate schedule 2. 13.2 percent times 962,000 -- sorry,
20 $962 million results in an allocation for rate
21 schedule 2 of the distribution plant services and
22 meters cost of $126.9 million.
23 So that's how we use the customer weighting
24 factor for services and meters to recognize that
25 larger -- the larger rate schedules, the commercial
26 and industrial rate schedules, are more costly to

basically install. So they get allocated a higher cost of the services and meters.

Is everyone still awake?

THE CHAIRPERSON: Can I ask you a question?

MR. GOSSELIN: Yes, you can.

THE CHAIRPERSON: How do you determine the weighting factor?

MR. GOSSELIN: The customer weighting factor? That is -- what we do is, we look at basically all of our meters that are in -- active today. So all the meters we have in the system today. And we look at them, if they're serving rate schedule 1, if they're serving rate schedule 2. So rate schedule 1 can have a number -- it can have ten different types of meters. And they all have a cost to them. And the cost we look at is generally the insured value, or the replacement value of these meters. So we have all the meters in service, the number of them. We have the value of those meters. And then we basically extrapolate that into a value of all the meters in rate schedule 1 versus all the meters in rate schedule 2. If you take all that value, divided by the customers, you get a cost per meter per customer. Meters and services.

So once we do that, we know a rate schedule 1, for example, may have a meters in service worth $150. So we just call that 1.0. If rate schedule 2,

1 when you do the math, has a meter set worth $225, if
2 you take $225 divided by the $150 of rate schedule 1,
3 you get an allocator -- or a factor, rather, that
4 you'll use to scale up your customers.
5 So it's a look at all the meters out there
6 by rate schedule, and figuring out how much is a meter
7 -- how much are the meter sets and services per
8 customer in each of those rate schedules, and then
9 creating a factor for the post-allocation. Does that
10 answer --
11 THE CHAIRPERSON: Yes, thank you.
12 MR. GOSSELIN: Okay. Yes, sir?
13 COMMISSIONER ENNS: Why replacement cost?
14 MR. GOSSELIN: Why replacement cost? Our assets are
15 pooled. We don't really have the value -- the
16 historical value of each meter set out there in the
17 utility. So it's very hard to derive a historical
18 cost for a meter set out there in the utility.
19 They're all into the 147 -- you know, the 473/478
20 account.
21 **Proceeding Time 10:03 a.m. T14**
22 Conceptually if you could get historical
23 value, and so you use historical value and historical
24 value --unless the meter prices have changed
25 substantially between the two over time, like a
26 commercial versus a residential meter, it should

1 derive the same number, but really just don't have the
2 data to do that. So we look at insured value or
3 historical value. Or sorry, insured value or rather
4 replacement value for everybody, not just one class.
5 So we'd get a factor using it that way. Just because
6 we just don't have the date for each meter set over
7 the 50 years that they've been in existence.
8 MR. ENNS: We've just got, like basically what's -- I
9 think you guys use Iowa curve, and that type of thing,
10 for your depreciation?
11 MR. GOSSELIN: Correct.
12 MR. ENNS: And that's just going to be for the class,
13 right?
14 MR. GOSSELIN: Yes. Yes. Yes.
15 MR. ENNS: Thank you.
16 MR. GOSSELIN: Pooled assets, yes.
17 Moving onto slide 28, again both the plant
18 and the rate base are used to allocate delivery costs
19 of service so they must be allocated first. So we
20 just talked through some allocation of plant and rate
21 base. The table below here shows a summary of the
22 plant and rate base allocated to each of the rate
23 schedules, each of FEI's rate schedules. So we went
24 through a few examples and we allocated about -- that
25 was about $2 billion of the 4.5 billion in rate base.
26 There's many many allocations that go on in the COSA

1 model that you can dig into. But this is the final
2 result. And I showed you net plant and rate base,
3 because we use both. And I'll show you a little bit
4 later, when allocating the cost of service.
5 So on rate schedule 1, we'll just look at
6 the rate base column in this case. Through all the
7 allocations that are done, functualization,
8 classification, allocation, rate schedule 1 was
9 allocated $2.5 billion of the $4.5 billion in rate
10 base. And so on down the rest of the rate schedules.
11 Slide 29, so once we've allocated our plant
12 and rate base, we move on to allocating --
13 functualizing, classifying and allocating our delivery
14 cost of service.
15 Deliver cost allocation, slide 30. We
16 have, from our test year, about 790 million -- from
17 our test year, rather, plus adjustments, $790 million
18 in delivery costs that need to be allocated in the
19 COSA. Depreciation expense embedded in the delivery
20 cost of service generally follows the same allocation
21 as plant.
22 The next slides, we're going to go through
23 a summary of the key allocators. So the key
24 allocators we use in the delivery cost of service
25 allocation and the amount that we allocated with them.
26 And then we're going to go through the details of

1 those allocations and then we're going to finish up
2 there with a summary of the delivery cost allocation.
3 Okay. Big slide, big table. This is slide
4 number 31. The table you see identifies six key
5 allocators that are used in the COSA. Those six key
6 allocators are aligned across the top and they are in
7 bold. FEI uses other allocators as well, but these
8 six are used to allocate approximately $568 million of
9 the $790 million of delivery cost. So these six are
10 used to allocate about 70 percent of our delivery
11 costs.
12 Along the top we have a description of the
13 allocators but I'm going to expand on them because
14 they might not be precisely clear what they are.
15 Peak day demand. This is the daily demand
16 that our rate schedule will require on a design day as
17 described in section 6.3.6 of our application. For
18 our heat sensitive rate schedules with firm demand,
19 the peak day demand is based on a regression of
20 consumption and temperature. We have an appendix that
21 goes through that calculation. I can't recall the
22 number of it at this point.
23 **Proceeding Time 10:08 a.m. T16**
24 For our larger industrial customers with
25 contracted firm demand volumes, the contracted firm
26 demand is used as the peak day demand so that these

1 customers are only allocated the costs based on their
2 contracted level of service. So we want to make sure
3 we're allocating to our larger customers what we have
4 contracted to actually deliver them.
5 FEI uses this peak day demand allocator in
6 the COSA model to allocate approximately $193 million
7 of our $790 million cost of service.
8 The next allocator is distribution rate
9 base classified as customer. As I mentioned in
10 previous slides, both plant and rate base are
11 allocated first and then the results are used to
12 allocate the delivery cost of service.
13 This is basically a rate base allocator.
14 Basically a result of the rate base allocation that we
15 did in the first step. It's used to allocate $121
16 million of our delivery cost of service by using the
17 results of the rate base functionalized as
18 distribution and classified as customer.
19 The next allocator we use is average
20 customers adjusted by the customer weighting factor
21 for administration and billing. This allocator is
22 used to allocate about $92 million of our delivery
23 cost of service and is simply the number of customers
24 in each rate schedule adjusted by the ratios we
25 discussed earlier when we discussed the customer
26 weighting factor for administration and billing.

The next allocator, number four in the columns, is distribution rate base classified as demand. So similar to distribution rate base classified as customer a couple of columns to the left. However, this uses the rate base classified as demand. The allocators used to allocate $76 million of our delivery cost of service.

The next column over, gross plant before general and intangible classified as demand. Basically it's the same as the allocator to the left, but instead of using the allocated rate base, it uses the allocated gross plant. This allocator is used to allocate $51 million of the delivery cost of service.

And then finally on the far right we have average customers adjusted by the customer weighting factor for services and meters. So similar to the average customers adjusted by the customer weighting factor for admin and billing, this is the one that's adjusted by the services and meters. We just talked through an example of that one when we allocated plant earlier.

This allocator is used to allocate $34 million of the delivery cost of service. It's derived in the same way as the average customers for the admin and billing. However, it uses the factors that weight the cost of services and meters relative to rate

1 schedule 1.
2 The table shows the detail of the
3 allocations to each of the rate schedules. The
4 following slides are going to go into the details a
5 little more.
6 Slide 32. So we'll go through each of
7 those columns that we see in the summary table over
8 the next six slides.
9 So $193 million of our delivery cost of
10 service is allocated using peak day demand. Most of
11 these delivery cost of service come from our
12 transmission and distribution functions. We classify
13 them as demand and we use peak day demand to allocate
14 them. The peak day demand in the table below for each
15 rate schedule is in the second column there. You've
16 probably seen before rate schedule 1 has a peak day
17 demand of 635 TJs per day and so on down the list.
18 **Proceeding Time 10:13 a.m. T16**
19 The percentage on the right is using -- is
20 just basically derived using those peak day demands
21 over the total. And then the cost allocation of the
22 $193 million follows along. For rate schedule 1, 50.3
23 percent of the 193 million is allocated to rate
24 schedule 1 based on peak day demand. 97.2 million.
25 Slide number 33. Distribution rate base
26 customer.

1 MR. ANDREWS: Before you move on --
2 MR. GOSSELIN: Yes?
3 MR. ANDREWS: If you wouldn't mind, I have a question.
4 This is Bill Andrews. A question about slide 32.
5 MR. GOSSELIN: Yes, sir.
6 MR. ANDREWS: Using the example of the RS 1 class, peak
7 day demand of 635.5, why does that not use the figure
8 adjusted for the peak load carrying capacity shown in
9 slide 26?
10 MR. GOSSELIN: So, there are many -- predominantly these
11 costs come from transmission. There are some from
12 distribution, but predominantly from transmission. We
13 don't use the PLCC everywhere. We use the PLCC only
14 on the costs, or the plant, that are there to serve
15 the minimum system, so the distribution, plant, mains,
16 basically.
17 So, when we split up the distribution plant
18 mains, there's a customer and a demand component. So,
19 it's used in that fashion to not double-allocate
20 demand to any of the rate schedules.
21 So moving on from there, we also have
22 demand-related costs in the transmission system. And
23 the transmission system is there to serve the peak day
24 demand. It's 100 percent peak day demand -- or,
25 sorry, it's 100 percent demand related. So when it's
26 100 percent demand related, there is no customer

1 component. So we're not trying to negate any double-
2 counting that may have happened because we split it
3 between customer and demand. So the transmission
4 system costs are considered all demand-related. So we
5 just use the entire peak day demand number of 635 to
6 allocate those costs. Because we don't split it into
7 customer and demand, there is no need to worry about
8 double-counting between a minimum system and the
9 balance.
10 So, I'm not sure -- I hope that answered
11 your question.
12 MR. ANDREWS: Yes, that does answer my question, thank
13 you.
14 MR. GOSSELIN: Okay.
15 On to 33. This is the second column from
16 the summary table. Most of these costs are
17 distribution related. We have 121 million point three
18 -- or, $121.3 million that have been classified as
19 customer. And we use the distribution rate base
20 classified as customer to allocate it. So, if you
21 look in the COSA model, of course we allocate. We
22 functionalize our rate base. We classify our rate
23 base, and then we allocate the rate base.
24 So the portion that's classified as
25 customers and allocated across the rate schedules,
26 using various allocators, sums to, for rate schedule

1, $1.2 billion. So the 1.2 -- so you'll see all the rate schedules have some allocation of distribution rate base classified as customer. So when you look at it all, it sums to $1.4 billion. So when you take the $1.2 billion that's been classified as customer, and allocate it to rate schedule 1, over the 1.4, you get 82 percent -- 82.4 percent.

So 82.4 percent of the $121 million is allocated to rate schedule 1. So this is a case where we use the pre-allocated rate base as a basis to allocate costs. Once again, that's why we have to do plant and rate base first.

Moving on to slide 34, this is the one where we use average customers adjusted for the customer weighting factor for administration and billing. Most of these costs come from our customer accounting function. So the amount is $92.4 million, all that from the table we've seen earlier. Classified as customer, and allocated using the average customers adjusted by our customer weighting factor for admin and billing.

So we move to the table below. We see our rate schedules on the left, and we see the customers in the next column. Those customers again are the customers that we'll see in our test year that we bring into the COSA.

Proceeding Time 10:18 a.m. T17

And then the next column over is the weighting factor for admin and billing. So this recognizes that some customers cost more to administrate and create bills for. We'll take RS 3 for an example, because it's the first one that has the ratio that's higher than 1.0.

So we started with 5,000 customers in rate schedule 3. We recognized that they are about 120 percent -- they are about 1.2 times more expensive to administer and bill than rate schedule 1, so we multiply it by 5040 by 1.2 to get 6,048 weighted customers. We derive the percentages using the weighted customers over the sum of the weighted customers. So rate schedule 3 is .5 percent. So of the $92.4 million that are allocated using this allocator, rate schedule 3 picks up $.5 million of it.

As you can see, rate schedule 1, which is our largest rate schedule, picks up -- or is allocated 70.3 million of the 92.4.

Slide 35, this is the amount that we used distribution rate base classified as demand to allocate. So we have $75.6 million of our delivery cost of service that are mainly distribution related costs, we've classified them as demand, and we're going to allocate them using the distribution rate base that's been classified as demand. So similar to

the side two slides ago, we have in the first column, the rate schedules. In the second column we have our distribution rate base that's been classified as demand and allocated to each of the rate schedules.

We use those amounts as ratios to develop our percentages, so $452 million divided by a billion dollars gets you 44.8 percent. So 44.8 percent of the $75 million is allocated to rate schedule 1 for a result of $33.9 million of the 75.

The next slide, number 36, this will talk through the gross plant before general and intangibles classified as demand. So this is very similar to the last slide where we had a rate base classified as demand. This one actually just uses gross plant before intangible and generals classified as demand to allocate these costs. So these again are mainly distribution related costs. We have $51 million there. They are classified as demand, and we use the results of our gross plant allocation to allocate these costs.

So on the left, rate schedules, second column over we have the allocation of gross plant to those rate schedules. From there we derive the percentage and apply that percentage to the amount of 51 million, to get our allocations into each of the rate schedules. So of the 51 million, 24.5 million

1 was allocated to rate schedule 1.
2 Finally, onto slide 37, is where we use
3 average customers weighted for service lines and
4 meters to allocate costs. Again, these are
5 distribution related costs. There's $34 million of
6 them. They've been classified as customer.
7 Our customers -- so I'll go through the
8 table below. We have our rate schedules on the left.
9 We have our customers from our revenue requirement,
10 our test year. We have our weighting factor for
11 services and meters, again recognizing services and
12 meters for rate schedule 2 are about 1.7 times the
13 costs of rate schedule 1.
14 **Proceeding Time 10:23 a.m. T18**
15 So we weight the customers based on those
16 proportions, and create a percentage, an allocation
17 percentage, to allocate the costs of 34 million that
18 have been classified as customer to each of the rate
19 schedules.
20 So finally on slide 38, we have a summary
21 of our delivery cost allocation. So I talked to
22 earlier, we have a delivery cost embedded -- in the
23 COSA of $790 million. You can see that at the far
24 bottom right of the table. About $12 million of that
25 is classified as energy, meaning the need to deliver
26 energy to our customers cause about $12 million of

this delivery cost. The need to serve our customers on the peak day, the peak day demand that they require is -- we classify at about $400 million of our costs to do that. And the fact that we had customers on the system that they joined the system, we've classified about $378 million dollars of the $790 as customer-related.

And then these are each of the allocations to each of the rate schedules. So you'll see rate schedule 1 in total was allocated 500 million -- 504 million, of the 790 million. And as you've seen earlier, there is many classifications, or many methods -- or, not methods, but many costs that we go through the COSA model, that we have to functionalize, classify, and decide on an appropriate allocator, and it will allocate costs out, and we end up with these results right here.

So RS 1 is allocated about 64 million -- or 64 percent of our total delivery costs of $790.

Yes. Question.

MR. WEAFER: Chris Weafer, Commercial Energy Consumers. And we're getting to the end of the presentation, I think, so thank you. It's been very clear and very effective.

What I understand from the prior workshops is that there has been no material changes in terms of

your approach to the steps within preparing the rate design application. There's been nothing material. This is the way you've done it in the past. You're consistent. It's been stable in the past, and so you see it as appropriate for this application. Is that a fair statement?

MR. GOSSELIN: I think that's a fair way to put it, yes.

MR. WEAFER: Or is there anything material that should be highlighted, where you've made tweaks that are -- would affect revenue to cost ratios, would be something that should be highlighted or commented on, or you're satisfied that this is pretty much a "stay the course" approach.

MR. GOSSELIN: Yeah. I mean, we took into account the stakeholder feedback. I mean, the one thing that we did do a little differently is the allocation of our EEC amortization. However, it really doesn't -- it's small enough, it doesn't really make an impact to the rate -- the rate schedules, RCs, anyways.

But it's essentially very similar to what we've done in the past. I can't think of any big material changes that we made that are affecting anything in particular.

MR. WEAFER: And the follow-up question, and thank you for that, is the -- over time, when you've applied this to the rate classes, you've had fairly stable

1 results in terms of the revenue to cost ratios that
2 fall out of this approach?
3 MR. GOSSELIN: From what I've seen, from the -- I've
4 looked at some of the 2001 and '12 revenue to cost
5 ratios. I know we didn't spend a lot of time in the
6 COSA in 2012, but the methods were similar to that,
7 and the revenue to cost ratios haven't really varied
8 widely from what I've seen. I know we have some
9 fellows that have been around quite a bit longer that
10 may be able to speak to something from the '93-'96
11 application. But from what I've seen, not a lot of,-
12 you know, big variances in the revenue to cost ratios
13 over the last couple of applications that we've put
14 in.
15 MR. WEAFER: Great, that's helpful. Thanks very much.
16 MR. GOSSELIN: Okay. Suzanne has a question?
17 MS. SUE: Hi. Suzanne Sue, Commission staff. I actually
18 have a question regarding -- since the total delivery
19 cost is $790 million, only $568 million are being
20 allocated using the allocators, is the remaining $22
21 million direct assigned?
22 **Proceeding Time 10:28 a.m. T19**
23 MR. GOSSELIN: No. There is -- I've tried to pick the
24 big ones, the top ones that would kind of show just
25 about -- show much of the allocations, but there's --
26 we have probably 30 or so allocators that we use in

the COSA model. Some of them -- you know, as we get down the list we'll allocate a little bit less and less and less. So I picked the top six biggest ones, just to go through as examples in here. So no, the rest of the costs are not allocated directly. We use other allocators in the COSA model to do so.

MS. SUE: Do you know what percentage if any of your -- well, you will know -- of any of the costs do you use direct assignment?

MR. GOSSELIN: I don't know the percentage, no. I know -- I can speak to we did direct assign rate schedule 46 costs from -- or we did direct assign Tilbury expansion cost of service directly to rate schedule 46. That net after revenues and costs was about 7 million short, but the cost themselves are about $40 million that we direct assigned to rate schedule 46, plus offset by the revenues.

And we also did do some direct assignment for meters and services for our industrial customers. I don't recall the percentages of those, though. But not a lot of our costs in the cost of service are direct assigned. Most of them are allocated using the various allocators we have.

MS. SUE: Okay, thank you.

MR. GOSSELIN: You're welcome.

So I think this is a good time to take a

1 break. The next few slides talk about, basically, the
2 summary COSA results and might be good for about a
3 ten- or fifteen-minute break. Fifteen? Ten is good?
4 So let's come back at 10:40.
5 **(PROCEEDINGS ADJOURNED AT 10:30 A.M.)**
6 **(PROCEEDINGS RESUMED AT 10:45 A.M.)** **T20/21**
7 MR. GOSSELIN: All right. Moving on to slide number 39.
8 So, we're going to talk a little bit about the summary
9 of the COSA results.
10 The next couple of slides are simply
11 basically putting in a different perspective the
12 slides -- or rather the schedules you'll see in the
13 appendices. First I'll cover a summary of the three
14 steps of the cost of service allocation. And then
15 we'll move on to the revenue to cost ratios before
16 proposals and rebalancing.
17 Slide number 40. We have three tables on
18 here. They essentially show the summary of the class
19 -- functionalization, classification and allocation.
20 The upper left table on the sheet here shows the
21 functionalization of the delivery costs. Tilbury
22 expansion is functionalized as storage, so it's
23 embedded in the storage function, as I noted earlier.
24 Transmission and distribution together are
25 allocated about -- or functionalized about 81 percent
26 of the delivery costs. So when you look at

1 transmission and distribution, that represents about
2 81 percent of the total delivery costs of our system.
3 The next table would be the table on the
4 lower left. And this shows the results of our
5 classification. So about 51 percent of FEI's delivery
6 costs of service is caused from demand placed on the
7 system and about 48 percent of it is caused from a
8 customer being on the system.
9 And then the table on the far right is the
10 final cost allocations by rate schedule. And you'll
11 see the costs themselves are allocated down the middle
12 column piece, and then the percentage of those costs
13 is on the right.
14 These tables are basically just a different
15 look at the schedules you'll find in the appendices in
16 the application.
17 Slide 41 shows our revenue to cost ratios
18 before our rate design proposals and any rebalancing.
19 The lower part of the table, you'll see
20 it's split into two. It shows RS 4, rate schedule 4,
21 rate schedule 7/27, and rate schedule 22
22 interruptible. These rate schedules do not drive
23 system capacity because they are interruptible. Rate
24 schedule 4 is interruptible in the winter-time, but
25 not so in the summer.
26 Since they don't drive any system capacity,

they're really -- they're not allocated any demand-related costs. Remember, about half of our system is demand-related costs. They're not allocated any of these demand-related costs because they are interruptible when demand is at its peak, or on a design day. So, when it's cold, and we need the capacity that they are taking, we interrupt them.

The charges within these rate schedules are not set using the allocated costs from the COSA but rather they're set at a discount to our firm rate schedules. So that's why their revenue to cost, margin to cost ratios, seem so out of whack. They're not allocated any demand cost, but their rates are set based on our firm demand -- or firm rate schedules.

So the upper part of the table, except for rate schedule 6 and 22A, all the revenue to cost ratios are very nearly within the 95-105 range, and the margin to cost ratios are within the 90 to 110 range. This is an indication that the revenues collected from each of these rate schedules is closely aligned with the costs caused by those rate schedules.

Bill?

MR. ANDREWS: Can you explain a little more about that marginal cost ratio --

MR. GOSSELIN: Is derived?

MR. ANDREWS: Yes.

Proceeding Time 10:50 a.m. T19

MR. GOSSELIN: So, the revenue to cost ratio is all the delivery costs plus all the gas that they would -- that a customer would pay us. So that's the revenue side. And the allocation, the cost side, is the allocated side plus the cost of the gas that they would buy from us. So the gas in the revenue part and in the cost is the same amount. So on the RC So on the MC we actually just strip out the gas piece. So it's the delivery cost of delivery revenue -- rather the delivery revenue we get from a customer – so for rate schedule 1 it would be the sum of their basic charge and their delivery charges for the year in particular – divided by the allocated cost, the allocated delivery cost not -- stripping out all gas and storage and transport costs.

MR. ANDREWS: So earlier on in the presentation you were talking originally about the whole revenue requirement, and then you said that for now on we'll just be talking about the delivery cost portion to do with the revenue cost ratio. Here you've brought back in the commodity cost and storage and transportation when you're displaying the revenue cost ratio. But you've taken it out again when you call it the marginal cost.

MR. GOSSELIN: That's correct. The cost of gas is out

for the margin to cost calculation.

And to clarify, the reason why I described it earlier as such, because the COSA model and what we've been talking through, is allocating the delivery cost of service, but ultimately in the end we'd like to look at the revenue to cost ratios, because ultimately people pay for gas and it's a part of their cost as well. So it's important to look at both the revenue to cost ratio and the margin to cost on the delivery side of things.

MR. ANDREWS: So why do you apply the range of reasonableness, the 95 to 105 to the revenue cost instead of to the margin cost? I think you just addressed that, but maybe you could elaborate.

MR. GOSSELIN: I think it's standard practice to look at the entire revenue that a customer would pay versus their entire costs. So that's why we do it. You could look at either one for reasonableness. Either the RC or the MC.

MR. ANDREWS: Okay, thank you.

MR. BYSTROM: Could you just clarify what the range of reasonableness is that we use?

MR. GOSSELIN: The range of reasonableness that we've used is 90 to 110 as we've described in the application.

MR. WEAFER: Chris Weafer, Commercial Energy Consumers,

1 and Chris has kind of gone where I wanted to go. And
2 this is a workshop, so it's not the time for the
3 debate of the range of reasonableness, so I don't want
4 to put you on the spot at all. But there is a concept
5 that -- I'm not sure if you're the person to address,
6 but just to throw it out there. We've got similar
7 ratios on the BC Hydro side of the equation and BC
8 Hydro has some legislative constraints.
9 But there's another difference with Fortis
10 in that what you're selling is gas. We've got in this
11 jurisdiction now clean energy legislation that is
12 pretty significant and is a change since you first
13 come up with these models back in 1991.
14 And so, at a high level, when Fortis looks
15 at these revenue to cost ratios, does it factor in the
16 appropriateness of sending the right price signal to a
17 customer for paying for what is non-clean energy,
18 which is gas?
19 MR. GOSSELIN: Well, those would be more rate design
20 question rather than the cost of service allocation
21 questions. I'm trying to think of a way to address it
22 though.
23 MR. WEAFER: Well, let me try it another way, because
24 that's not my intent. We're talking about what's
25 reasonable and a factor in what's reasonable in
26 sending the appropriate price signal to a customer if

they're burning non-clean energy and the idea that they would pay the actual cost of service would be something that would be reasonable in that environment.

So it's not for debate now, I just -- I wanted to throw it out there, because again the commercial customers see similar ratios with Hydro. There we are more constrained. Here we are obviously going to take a bit more issue with it, and I just want to put that out there as you assert these are reasonable ranges. We don't agree. So I can leave it at that. Now is not the time for debate, but I just wanted to make sure the seed was planted.

Proceeding Time 10:55 a.m. T23

MR. GOSSELIN: Okay, thank you. Moving onto slide 42. Now we get to do it all again for Fort Nelson.

So for Fort Nelson we bring in the test years as well. For Fort Nelson the test years are 2018 costs from our 2017-18 approved revenue requirement. The approval was just last year. And so we have approved costs for 2018 that we bring in and allocate in our delivery costs -- in our COSA model. So the delivery costs we bring in again are based on the 2018 forecasted delivery costs in the 2017-18 revenue requirement for Fort Nelson.

For Fort Nelson we also have a couple of

1 adjustments that we make in the COSA to the test year,
2 and we'll talk through those adjustments in the next
3 couple of slides.
4 So in our test year, in our revenue
5 requirement for Fort Nelson, we had forecast two Rate
6 Schedule 25 customers. So embedded in Rate Schedule
7 25 in the revenue requirement for the test year we had
8 two Rate Schedule 25 customers. One of those Rate
9 Schedule 25 customers has since moved to Rate Schedule
10 -- or Rate 2 -- 2.1 rather. There was zero volume for
11 this customer in Fort Nelson. However, there were
12 revenues embedded in the revenue requirement based on
13 their minimum charges. In the revenue requirement
14 their minimum charges were based on the Rate Schedule
15 25 minimum charges, which are different than those
16 that they're paying today under Rate 2.1.
17 So we made an adjustment in the COSA for
18 the difference in revenue that we would collect from
19 this customer now that they're under Rate 2.1, and the
20 difference is $24,000 less revenue that we'll collect
21 for them -- that we put embedded into the COSA.
22 We also for this customer use a load factor
23 -- sorry, we use a load factor for the RS 25 customer
24 that's still an RS 25 customer, Fort Nelson, of 40
25 percent. Rate Schedule 25 in Fort Nelson is designed
26 for customers with load factors, you know, greater or

1 equal to 40 percent, similar to the Rate Schedule 25
2 design that we have for customers in FEI.
3 So what we're finding is that customer up
4 there is not your typical Rate Schedule 25 customer
5 right now. They're under some business constraints
6 that they're really not what would consider a typical
7 Rate Schedule 25 customer. However, for allocation
8 purposes in the COSA we felt it was reasonable to use
9 a 40 percent load factor, which is kind of the bottom
10 end load factor that would be used -- that we would
11 assume a Rate Schedule 25 customer in Fort Nelson
12 would have. So we use that for allocation purposes in
13 the COSA.
14 Also for Fort Nelson, the revenue
15 requirement has a single line item called Shared
16 Services. That represents all the O&M allocated to
17 Fort Nelson from FEI except for distribution O&M in
18 Fort Nelson which is directly forecast. So 532,000 of
19 shared services allocated from FEI represents all the
20 O&M except distribution O&M in Fort Nelson.
21 In the COSA, the shared services amount of
22 532,000 is split into parts based on FEI's O&M
23 percentage. So use the same percentages that we use
24 to split FEI's O&M up into an activity view and apply
25 it for Fort Nelson. Now, of course we don't include
26 the storage piece, they don't have any LNG storage in

1 Fort Nelson, but essentially we use the same
2 percentages to split up the $532,000 single line item
3 into component parts for functionalization,
4 classification and allocation purposes in the COSA
5 model for Fort Nelson.
6 And of course for Fort Nelson we also have
7 supporting studies, as we do for FEI. We have a
8 minimum system study and a PLCC adjustment, and we
9 also have a customer weighting factor for Fort Nelson.
10 Both of those studies are used in the same way that we
11 use them for FEI. We use a minimum system to help
12 split up our distribution mains and system into
13 customer and demand components.
14 **Proceeding Time 11:00 a.m. T24**
15 And we use the customer weighting factors, recognizing
16 that some customers cost more to administer and
17 connect than others.
18 The minimum system for Fort Nelson -- this
19 is slide number 48. Again, this recognizes that the
20 distribution system's in place to serve, in part,
21 because a customer connected, and in part to serve a
22 demand -- a peak day demand. There is 116 kilometres
23 of distribution mains in Fort Nelson. When priced at
24 our minimum of 60 millimetres poly, the value of the
25 distribution mains comes in at $11.6 million -- or
26 sorry, $5.3 million.

When compared to the value of the distribution mains at their weighted cost, meaning that they're different diameters, of $11.6 million, we have a minimum system for the distribution mains for Fort Nelson of 46 percent. Meaning 46 percent of distribution mains cost is classified as customer, and 54 percent is classified as demand-related.

And we use a PLCC adjustment as we do in FEI, and it's equal to FEI's PLCC of .205 gigajoules per day per customer.

Suzanne?

MS. SUE: Hi, Suzanne Sue, BCUC. Can you tell me why you're using the FEI average PLCC adjustment factor for Fort Nelson?

MR. GOSSELIN: We did the PLCC calculation on the system as a whole, the entire system in the Mainland. So the Mainland and Fort Nelson all put together, to calculate the PLCC. So that's why we use the 205 in both FEI and Fort Nelson.

MS. SUE: Can you explain why you didn't do a separate number for it? Because they are two different service areas.

MR. GOSSELIN: I think just basically felt it was reasonable to do it as an entity as a whole.

MS. SUE: Okay, thank you.

MR. GOSSELIN: Thank you.

For Fort Nelson, we also have the customer weighting factor study that we do for meters and services. And we have the customer weighting factor that we use for administration and billing. Again, their weighting is relative to rate schedule 1. So, for rate schedule 2.1, you'll see their meters and services are about 1.6 percent -- or 1.6 times the cost of rate schedule 1, And so on. And for admin and billing, they're similar to -- they are actually equal to the same factors that we use for FEI, because it is the same group that administers and bills Fort Nelson customers.

On to slide 50. So, similar to FEI, we have to allocate plant and rate base for Fort Nelson first, because it's used as an allocator for much of the -- many of the costs in the delivery cost of service.

Slide 51, we see that we have a rate base for Fort Nelson of about $11.2 million. The allocation methods that we use in the COSA model are very similar or equal to the FEI allocation methods. On the left we have a pie chart similar to the one we had for FEI that shows you our rate base, categorized. So we have about half of Fort Nelson's rate base, is transmission plant assets. Nearly -- you know, nearly a half of the balance of it is distribution plant

1 assets. And then we have general and intangibles,
2 making up basically the balance of rate base.
3 **Proceeding Time 2:25 p.m. T25**
4 So those are the assets that make up the
5 bulk of the rate base for Fort Nelson. And then on
6 the right we have the summary of the plant and rate
7 base allocations for Fort Nelson.
8 So I'm not going to step you through many
9 of the alloca- -- all the allocations that we did for
10 FEI because they are really basically the same for
11 Fort Nelson, it's just applied to a different cost
12 base.
13 For rate schedule 1 we have a rate base
14 allocated to the of 5,967,000 or the 11 million 228.
15 MR. HACKNEY: Rick, Tom Hackney here. Can you remind me
16 how many customers you have in Fort Nelson?
17 MR. GOSSELIN: In Fort Nelson we have 2,500 or
18 thereabouts. About 2400 I believe, Tom.
19 MR. HACKNEY: Thank you.
20 MR. GOSSELIN: Slide 52 is the delivery at cost
21 allocation summary for Fort Nelson. Fort Nelson has a
22 $2,489,000 delivery cost of service that we allocate
23 in the COSA model for Fort Nelson. As mentioned
24 earlier, depreciation expense embedded in a delivery
25 cost of service follows the same allocation as plant.
26 So wherever plant is allocated, the expense or the

1 depreciation expense is allocated as well.
2 And then we have a summary below, at the
3 bottom of the slide, that shows the summary of the
4 delivery cost allocation similar that I showed for
5 FEI, where we have a $19,000 of their revenue
6 requirement is classified as energy, and $1.3 million
7 of it is classified as demand, and $1.1 million of
8 their $2.4 million revenue requirement is classified
9 as customer.
10 You'll see rate schedule 1 is allocated
11 about 1.4 million of their $2.14 million revenue
12 requirement in the cost of service allocation model.
13 That's about 56 percent of their total delivery cost
14 of service.
15 Again, for -- we're onto slide 53. We're
16 going to talk a little bit about the summary of the
17 COSA results for Fort Nelson, the same way as we did
18 about FEI.
19 Slide 54 we have an upper left table that
20 shows the functionalization of the delivery cost of
21 service. There's no storage function for Fort Nelson,
22 so you won't see that in the list. Transmission and
23 distribution together are allocated about 93 percent
24 of the delivery cost of service. So a lot of their
25 costs are functionalized as transmission and
26 distribution.

The lower left table you'll see the classification for Fort Nelson's costs. Similar to FEI's, it's about 50-50 demand customer classification. A little heavier on demand than customer than FEI.

And then on the right-hand side you see the total costs that are allocated to Fort Nelson rate schedules. Or rates, rather. Rate 1, 2.1, 2.2 and rate schedule 25, totaling $2.4 million. And then the percentage on the right. So rate 1 is allocated 56.7 percent of Fort Nelson's total delivery cost of service.

And then the next slide, slide 55 we have Fort Nelson's revenue to cost ratios before rate design proposals and rebalancing. Fort Nelson's revenue to cost ratios are all outside the 90 to 110 range. This indicates that some rebalancing is required.

This concludes my presentation on the cost of service -- oh, there we go. Bill.

MR. ANDREWS: I have a question going to back to the discussion that we had earlier about the revenue to cost ration and the margin to cost ratio. I hope you're going to confirm my understanding here so that otherwise I'll be totally confused.

Proceeding Time 2:25 a.m. T26

In the BC Hydro cost of service allocation context, there has been a suggestion that instead of using an average cost of service concept there should be the use of a marginal cost of service concept. Am I right that Fortis's cost of service approach is entirely on an average cost basis and the use of the term "margin" in that ratio does not reflect the concept of a marginal cost of service analysis?

MR. GOSSELIN: You're correct. The term "margin" doesn't refer to a marginal cost of service. We use a historical embedded cost when we do our allocations not a marginal cost approach. So the margin --

MR. ANDREWS: Thank you. I should have said "embedded" instead of "average".

MR. GOSSELIN: Yes, exactly, yes.

MR. ANDREWS: Thank you.

MR. GOSSELIN: Are there any other questions about the cost of service allocation for FEI and Fort Nelson? Yes, Chris.

MR. WEAFER: Just the same question I had earlier. In terms of what you're seeing as those revenue to cost ratios for Fort Nelson, are they also what you would have seen historically, that there's been no changes in how you've allocated under Fort Nelson, and if you look back in time these would be roughly the revenue to cost ratios that would have existed there?

1 MR. GOSSELIN: They are similar to what we've seen in the
2 2012 when we did our amalgamation application, I
3 believe. But further back than that, I don't know
4 when the last time we did a COSA for Fort Nelson.
5 Ed, do you have some history on that?
6 MR. MOORE: As part of an IR in the revenue requirement,
7 I think it was about in about 2004, we prepared a COSA
8 then. Back in -- previous to that there was one done
9 in '93 but was never filed because Fort Nelson didn't
10 become part of the Phase B rate design, and so you
11 really don't have kind of like a history like you've
12 got in FEI for comparative for the COSAs. It just
13 doesn't happen.
14 I think really what you've got to rely on
15 is what Rick was saying, is we did one in 2012 as part
16 of the postage stamp application.
17 MR. WEAFER: It's also been stated from that one to this
18 one, the percentages are (inaudible).
19 MR. GOSSELIN: Between 2012 and this one? I think the RS
20 25 changed a little bit because of the nature of
21 what's happening to that customer in Fort Nelson, but
22 I believe it's fairly stable.
23 MR. WEAFER: And I'm just trying to confirm that what
24 you're doing is accurate and stable. I'm not
25 challenging it.
26 MR. GOSSELIN: No, I understand.

1 MR. WEAFER: What I'm hearing is that for the overall
2 utility and for Fort Nelson, the revenue to cost
3 ratios have stayed fairly stable over a shorter period
4 of time on evidence based for Fort Nelson, a longer
5 period of time on the overall utility. You're
6 satisfied that the approach is robust and the
7 percentages don't change materially.
8 MR. GOSSELIN: I'm satisfied that the approach we took
9 definitely follows industry practice and for FEI
10 certainly, you know, very similar to past COSA models
11 and logically, I mean, the same approaches applied to
12 Fort Nelson would make sense considering it's a gas
13 utility that we have experience in running and we
14 understand the cost embedded within that gas utility.
15 So using a similar approach for Fort Nelson
16 is logical considering our system knowledge and
17 industry practice. Like I said as far as consistency
18 and results for Fort Nelson, I honestly can't speak to
19 it precisely up here, because I don't really recall
20 finding those COSAs for '04 and '96.
21 MR. WEAFER: That's fine. No, thanks very much.
22 MR. TOKY: Are there any other questions that we have on
23 this part?
24 MR. GOSSELIN: We will talk a little later about the
25 results on the COSA after rate design proposals and
26 some rebalancing approaches that we've considered. So

1 this isn't the final, final discussion on COSA and
2 revenue to cost ratios. So I just want to let you
3 know that's coming up later.
4 All right, thank you very much.
5 MR. TOKY: So just looking at the time now, we are
6 basically getting into our second part of the
7 presentation, which is about the rate design proposals
8 and the approval sought, and I'm just thinking is
9 maybe this is a logical time to start that, but we
10 might not be able to complete the first bit of that.
11 So there's that option, or there's an option to break
12 out for early lunch and come back and start that whole
13 discussion all together.
14 So I just want to know if there is a
15 preference to do -- or go for one option or the other.
16 **Proceeding Time 11:15 a.m. T27**
17 THE CHAIRPERSON: The Panel would ask that you keep
18 going, if that's all right with everyone else.
19 MR. TOKY: Okay, that's great. So, what we have next is
20 Rouzbeh Mehrazma, who is our regulatory policy
21 manager, and he's going to present and start on the
22 rate design proposals, which is the part 2. Start
23 with the residential rate design.
24 MR. MEHRAZMA: Hello, everybody. Hello. Rick is a
25 little bit taller than me.
26 My name is, as Atul mentioned, Rouzbeh

1 Mehrazma. You can call me Rouz if it's any easier.
2 And today, hopefully, I will present you a brief
3 summary of FEI's rate design proposal for residential
4 rate schedule, or rate schedule 1, or RS 1.
5 But before I start, let's see where we are
6 at this point of presentation. So we have a very good
7 comprehensive review of the COSA. The costs are now
8 allocated to each rate schedule, and the question that
9 we have in front of us right now is, how are we going
10 to collect those costs from each rate schedule?
11 Now, to answer that question, we need to
12 consider multiple items. Customer characteristics
13 specific to that rate schedule is one. Rate design
14 considerations, such as for example Bonbright
15 principles, rate design and rate impact analysis.
16 Maybe customer feedback. Maybe government policies.
17 Jurisdictional comparisons. Whatever it's relating
18 and appropriate. So with that, with that
19 introduction, I will invite you to go to the next
20 slide. It's slide number 58.
21 So who is a rate schedule 1 customer? Rate
22 schedule 1 customers include single family residences,
23 separately metered single family townhouses, row
24 houses and apartments. So it is important to note
25 that if you are a residential apartment, like the one
26 that we have in here, Yaletown, that you are not

1 individually metered, and that the natural gas bill is
2 paid by the strata, and you are not any more under
3 rate schedule 1. More probably served under schedule
4 3-23 or 5-25, but not 1.
5 Based on this definition, about 91 percent
6 of all of our customers are in this rate schedule.
7 That's close to 900,000. Now, this is an important
8 number because when you are dealing with 900,000
9 customers, with different backgrounds, then it is very
10 important that you make sure that everybody
11 understands the rates. So the simplicity of the rates
12 is essential, and it's also important that a majority
13 of customers accept the rate.
14 We can also see that 35 percent of our
15 total throughput is -- belongs to rate schedule 1.
16 And the revenue is about 59 percent. Now, this is
17 revenue, so it includes cost of gas. But if you look
18 at the margin, it's not that different. It will be
19 less, but not that different.
20 You can also see the two graphs that we
21 have here. One is customer mix. So SFDs, or single
22 family dwellings, are the biggest portion of our
23 customer base for residential rate schedule. But this
24 has been changing a little bit during the recent
25 years. The trend is towards more multi-family
26 dwellings and less SFDs. However, as I told you, some

of these new MFD, new high rises, they are not individually metered, so they're not going to be served under rate schedule 1.

The other one is end use. 64 percent of natural gas used for residential rate schedule is -- belongs to space heating, followed closely by -- not closely, actually, but followed by water heating and other natural gas uses.

Yes?

MR. HACKNEY: In regard to the gas used in -- under commercial rates for condominiums and apartments, do you have just a rough sense of how much that energy consumption is?

MR. MEHRAZMA: I don't. I don't think we have separated residential apartments in rate schedule 3-23 from the rest. I don't think we have done that. Maybe it's something you can look into. I don't know.

Proceeding Time 11:21 a.m. T28

MR. GOSSELIN: Tom, that would be a question that would probably be best for the IR process. It'll require some digging in to get that.

MR. HACKNEY: Okay, thank you.

MR. MEHRAZMA: Yeah. And so the order here is like cooking and, you know, decorative fireplaces, barbecues, stuff like that.

Let's go to slide number 59. Here you have

the normal distribution function for the 2016 residential consumption. You can see that it's a normal distribution with its beautiful Bell curve and slightly skewed to the right. And the red line is the S curve, which is the cumulative distribution function for the normal distribution.

Now, about 10 percent of our customers, if you look at the cumulative S curve, you will see that 10 percent of our customers consume less than 28, 11-10 percent, less than 30 GJ per year, based on 2015 normalized consumption. And on the other side about 10 percent consume more than 140. I should also mention that this excludes the outliers. So we have defined outliers as anything above the 99th percentile.

The residential use per customer. So it is well known that during the last couple of years we have had declining use per customer for residential customers. Indeed in the last ten years the UPC has declined by more than one percent each year on average. So this is one of the -- probably if you want to compare now with 2001 of the biggest differences for residential rate.

With this three slide I will conclude my comments on the customer characteristic section. I think it is enough for us to get into the actual discussions and analysis, but I invite you to go and

check the application section 7.2 for more detailed information.

Slide number 61. So we have reviewed the customer characteristics. Let's talk about customer feedback. We did retain the services of Sentis Research, which is an independent B.C. based, Vancouver-based research company, not a utility, and they did two questionnaires for us. One for Fort Nelson and one for FEI, obviously because they have different rate structures. But there are also common questions between the two.

The survey had three main areas of focus. One was understanding of current rates and bill components. Two was preferences regarding rate design concentrations and also the last one was assessment of rate structures based on customers' understanding.

So on the first topic I can tell you that about 84 percent of our customers responded that they understand how their bill is calculated, either very well or somewhat well. This is a good number when you're dealing with 900,000 customers. Obviously this is not -- this is a statistic, so it's statistically significant enough.

Also we asked them, we defined the individual component of their bills and we asked them if they understand each one, if they understand what

1 is basic charge there and do you understand what is
2 midstream, do you understand, you know, taxes and
3 levies and the rest. And in total about 72 percent of
4 FEI respondents indicated that they understand all
5 components of the bill very well or somewhat well.
6 **Proceeding Time 11:26 a.m. T29**
7 Now, going to the second topic, preferences
8 regarding rate design concentrations, we wanted to
9 know how our customers think with regards to rate
10 design principles and we wanted to understand their
11 preferences. So we asked them to rank different rate
12 design principles. The results was that the
13 simplicity of the rates was the most important rate
14 design principle from their point of view. The rest
15 of the rate design principles were rated a little bit
16 less. Not a little -- but all of them were almost the
17 same level. So at the top was, the most important was
18 simplicity and then the rest were rated almost at the
19 same level.
20 The last topic is about the assessment of
21 rate structures. So on this subject we first define
22 different rate structures to the respondent. So we
23 define them, what is flat rate, what is declining
24 block rate, what is inclining block rate, and then we
25 ask the respondents to rank each rate structure
26 relative to rate design principles. So for example,

1 the question was like this: Which one of the rate
2 design options would result in the most stable natural
3 gas bill month to month? Rate stability principle.
4 And we asked them to rank.
5 The result was as follows. So again, flat
6 rate was, from their perspective, was the easiest to
7 understand. Also it was the most stable, and also
8 that received the highest score for economic fairness,
9 interestingly.
10 The only principle that flat rate didn't
11 score better than the rest was on efficiency
12 principle. So promoting efficiency, and that was the
13 inclining block rate which scored better. So this
14 shows that actually our customers understand on the
15 rate structures and the rate design principles pretty
16 well, I would say.
17 Again, the detailed version of service
18 methods and results can be found in appendix 4-5 and
19 you can ask from Sentis themselves in the IR process
20 any questions that you have on the specific issues
21 related to the survey.
22 Let's go to slide number 62. So, we now
23 know that customers prefer flat rate, you know, in
24 general based on the survey results. What about other
25 rate design considerations?
26 So ease of understanding and

1 administration, and this is relative to other rate
2 structures that we defined and evaluated in the
3 application, including the declining block rate,
4 inclining block rate and seasonal rate. Flat rates
5 was easiest to understand for sure. Because there is
6 this understanding, it will probably lead to more
7 customer satisfaction and less cost pressures.
8 On the issue of economic efficiency and
9 economic fairness, we can say that relative to other
10 rate structures, flat rates are -- flat rates can be
11 considered a neutral option. Why? Because they do
12 not really, you know, promote any specific kind of
13 consumption. They don't promote -- or they don't
14 discourage or encourage you to consume in a specific
15 way compared to other rate structures.
16 Flat rates, for sure, will lead to better
17 rate stability and less bill impact. Because if you
18 want to transition from the current flat rate that has
19 been in place for close to 20 years, and you go to any
20 other rate structures, then you will have -- first of
21 all you will have additional cost, like billing costs
22 and stuff like that, but also obviously there are
23 people who will be impacted by this transition.
24 **Proceeding Time 11:31 a.m. T30**
25 Depending on how you want to implement it,
26 depending on where the threshold, for example, for a

1 declining or inclining block rate would be, there
2 would be a huge number of people that can be impacted
3 by a transition from flat rate to any other rate
4 structure.
5 And finally we will review this a little
6 bit more later, but the majority of Canadian
7 utilities, natural gas utilities, use flat rate for
8 their residential rate class.
9 So based on all of these considerations, we
10 believe that the existing flat rate provides the best
11 balance among competing rate design principles, and we
12 propose to maintain the current flat rate as it is.
13 So now I'm on slide 63. So the next couple
14 of slides is going to address the issue of fixed
15 charges versus variable charges. And we are going to
16 review this from two opposing views. One for increase
17 in basic charge relative to variable charge,
18 volumetric charge, and one against it. Because there
19 are competing rates, I suppose, on this issue.
20 So, in this slide, we compared the fixed
21 costs, right from COSA model, with current fixed
22 charges. The current fixed charge is in the form of a
23 daily basic charge it has, but here for analysis
24 purposes we have a conversion to a monthly basic
25 charge of $11.84 per month, as it is today.
26 Now, in the second column there, you know,

1 you have the unit costs based on COSA results. The
2 $27.1 dollar per month is basically calculated like
3 this. So if you take the customer -- the costs that
4 were classified as customer related in the COSA, and
5 then you divide, and for rate schedule 1, and then you
6 divide that by number of customers in rate schedule 1.
7 And then you divide that by 12, and you get to $27.1
8 per month per customer.
9 Now, if you divide $11.84 per month, which
10 is our current, you know, basic charge, by 27.1, you
11 will get 44 percent. Which that basically means that
12 the current basic charge recovered is about 44 percent
13 of the customer attributed cost for rate schedule 1.
14 Now, the question is this here, is this.
15 Is it fair or not? That it's only 44 percent.
16 Remember I told you that about 10 percent of our
17 customers consume less than roughly 30 GJ per year.
18 That basically means 10 percent of the customers, if
19 you calculate, you know -- if you calculate the
20 monthly bill that they pay, that 10 percent of
21 customers do not even pay their customer-related
22 costs, forget about the demand part. They do not pay
23 $27 per month. So, that's a question.
24 It's also important to note that since
25 2009, the basic charge has remained unchanged. So,
26 and that was because of the negotiated settlement part

of the 2010/2011 revenue requirement. And in alignment with energy policies of the government at the time, the basic charge was fixed at 2009 levels. Obviously, you know, it was just after the 2007/2008 policies that in 2008 the carbon tax was introduced, and so on. So it was in alignment with all of those policies.

Now, in the next slide, I will review with you what has been the impact of keeping the basic charge constant.

Here you have the impact of delivery rate increases -- on slide 64, by the way. Here you have the impact of delivery rate increases on the delivery portion of annual bill. For the customer with 25 GJs year consumption, it costs them about 85 GJ per year consumption and it cost them 145 GJ per period consumption.

Proceeding Time 11:36 a.m. T31

Now, just look at the trend lines here and look at the slope of the trend lines. You can see that the slope for 145 GJ per year customer is much more than the slope of trend line for 25 GJ customer. To put that in terms of percentages, the delivery margin charged from 2009 to 2016 has -- sorry, the delivery margin increase from 2009 to 2016 has been about 16 percent for 25 GJ customer, 30 percent for 85

1 GJ customer and 36 percent for 145 GJ customer.
2 So the question is how does this align with
3 fairness principle and cost causation. The service
4 that the guy who was 145 in 2009 is the same service
5 that they are receiving today, but they are -- by
6 holding basic charge constant, higher use customers
7 are bearing greater share of delivery margin
8 increases.
9 This is the last slide for the pro basic
10 charge increase. It is a jurisdictional comparison
11 that we have done. As I told you earlier about the
12 majority of natural gas utilities use a flat rate for
13 the residential rate schedule, as you can see.
14 The Y axis represents the percentage of
15 monthly fixed charges to total delivery charges based
16 on monthly consumption of 7.5 GJ per month. So about
17 90 Gj per year. And we did that to be able to compare
18 them in a different basic charges in a more meaningful
19 way.
20 Now, maybe it will be interesting for you
21 to know that four utilities here actually do not have
22 a separate rate schedule for the residential
23 customers, but the residential customers are part of a
24 more heterogeneous group segmented by consumption as
25 "low use".
26 So when you look at this, I think you can

1 conclude that an increase to the residential basic
2 charge is not inconsistent with the fixed cost
3 recovered in other jurisdictions.
4 By the way, the detailed rates can be found
5 in appendix 7-2.
6 So here I'm going to talk about competing
7 rate design principles when it relates to increasing
8 basic charge. One, government energy conservation
9 policies. I told you, you know, the reason that we
10 hold the basic charge constant in 2009 was because of
11 the government policies, to be in line with those
12 government policies. So nothing has changed. Those
13 government policies are still there.
14 Also we know that, you know, based on
15 economic theory if you have excessively high basic
16 fixed charges, then, you know, that will impact
17 customers behaviour and for the case of a natural gas
18 utility, a distribution utility, it may -- if it's too
19 high then people may lose their incentive to invest
20 in, you know, efficiency measures.
21 So a higher basic charge would discourage
22 customers engagement in energy saving initiatives, as
23 we can see. And whatever increase that we want to
24 apply, we should consider this.
25 The second rate design consideration is
26 rate stability and bill impact. Obviously you cannot

1 increase by whatever percentage you want. It should
2 consider the rate impact and there should be no rate
3 shock.
4 And finally, the feedback received from the
5 stakeholders. You know, we had a workshop last year,
6 and honestly there was not that much appetite for any
7 change in basic charge based on the results of the
8 workshop.
9 **Proceeding Time 11:41 a.m. T32**
10 So if you consider everything that I just
11 mentioned, we believe that a one-time 5 percent
12 increase in the basic charge and offsetting decrease
13 in the volumetric charge would be reasonable and it
14 would be a balance measure and it will create a
15 reasonable balance among competing rate design
16 considerations.
17 First of all, a 5 percent increase is not
18 going to lead to any kind of rate shock, obviously,
19 you know. There will be a zero rate impact for an
20 average use customer because it's revenue neutral. So
21 any increase that the basic charge, you will decrease
22 the variable charge.
23 Yes.
24 MS. SUE: Suzanne Sue. What do you consider rate shock?
25 Is rate shock in your opinion a zero rate impact on
26 the bills? One percent, 5 percent? What do you

generally consider to be rate shock?

MR. MEHRAZMA: I think generally it's about 10 percent, but it also, you know -- I think this was also discussed in BC Hydro's last proceeding, that it also depends on dollar amount. If the 10 percent would be like 50 cents, it depends -- well, it's not. But if it was then, probably that is not going to be rate shock, you know. But it's usually about 10 percent, I think.

MS. SUE: Okay, thank you.

MR. MEHRAZMA: Yeah. So this will be a view of bill impact for an average customer, but the maximum bill impact will be 5 percent obviously for a customer's with zero consumption. And for the majority of customers the bill impact will be -- go on.

MR. HACKNEY: Thank you. The 5 percent amount, did Fortis look at 2 percent and 10 percent and 15 percent, a range? And if so, what were the conclusions?

MR. MEHRAZMA: Yeah. So we didn't look at 2 percent. We looked at the 5, 10, 15.

MR. HACKNEY: Yeah.

MR. MEHRAZMA: And, you know, based on the competing rate design principles we thought that 5 percent would be the most reasonable, because we really did not want to -- we wanted to be aligned with the current policies

and procedures.

MR. HACKNEY: Okay, and -- okay, thank you.

MR. MEHRAZMA: So for the majority of customers the bill impacts from this will be less than one percent, either decrease or increase, but less than one percent.

Government policies. Obviously, I mean 5 percent is not that much and it's not going to discourage customers' engagement in energy conservation policy initiatives, because even if you have 100 percent of your delivery charge recovered in fixed charges, you're still going to have a significant amount of your bill that's going to be recovered to volumetric charges, you know. Cost of gas, carbon tax, midstream. They're always going to be recovered in terms of volumetric charges. If you do the rough calculation, but right now about 50-50. So if 50 percent is delivery and basic charge and the 50 percent is the rest. So a 5 percent increase is not going to really discourage anybody from DSM activities, we think.

And finally cost causation. It doesn't solve the issue but it moves towards improving the alignments between fixed costs and fixed charges. So based on these considerations we thought that a one-time 5 percent increase would be reasonable.

Slide number 68, this is just really a summary. So FEI is proposing a residential rate design that maintains the current flat rate with a fixed daily basic charge and a flat volumetrics delivery charge. And we think that it is reasonable to increase the basic charge and decrease -- to increase the basic charge by 5 percent and to decrease the volumetric charge by the corresponding amounts.

And that will conclude my presentation. If there is any questions I'm happy to answer.

THE CHAIRPERSON: Okay, thanks, Rouz. So I think it's a logical time for us to take a lunch break. Maybe an hour, so we can be back here at around 12:50. Probably that's better. Thank you.

(PROCEEDINGS ADJOURNED AT 11:46 A.M.)

(PROCEEDINGS RESUMED AT 12:56 P.M.) **T33/34**

MR. TOKY: Well, welcome back, everyone. My name is Atul Toky. I'm manager, rate design and tariffs.

So in the morning, Dave basically took us through the context of the rate design application. He did talk about a little bit on the FEI rate design history, and then we had Richard talking about the cost of service allocation model, some of the high-level assumptions, the methodology itself, and the results, before any proposals, any rate design proposals. We also had Rouz, talking about the

1 residential rate design.
2 So up next, I'm going to talk about the
3 commercial rate design, which is also included in
4 Section 8 of the rate design application. I have used
5 some charts and tables in my presentation, and have
6 included references in the slides where those can be
7 found in the application as we go. I'll be happy to
8 respond to any questions as we go, but we do have a
9 lot of material to go through after lunch session as
10 well. So in total we have around, I think, 128
11 slides, and we are on slide number 70 now. We'll try
12 our best to respond to those questions, but if we are
13 challenged for time and maybe we are getting into a
14 discussion, or issues that need more time, then maybe
15 I would basically ask you to put that for our
16 regulatory process, which we have in front of us.
17 Moving on to slide number 70, commercial
18 customer characteristics. So, who are commercial
19 customers? Commercial customers include small
20 commercial customers, which are served under rate
21 schedule 2, with normal annual consumption less than
22 2,000 GJs, and large commercial customers, served
23 under rate schedule 3, and rate schedule 23. Rate
24 schedule 23 being the transport service, meaning they
25 get the delivery service from FEI.
26 And the normal annual consumption of those

1 customers, the large commercial customers, is more
2 than 2,000 GJs.
3 As shown in the table above in this slide,
4 FEI is currently serving more than 90,000 commercial
5 customers, which amounts to roughly about 9.3 percent
6 of FEI's total customer base. Out of these, about
7 85,000 customers are small commercial customers.
8 In terms of the annual demand which you can
9 also see on the table above, roughly a bit more than
10 quarter of FEI demand is coming from commercial
11 customers, with small commercial demand around 14
12 percent of FEI total demand.
13 Pie charts on the slide, which is the
14 bottom part, shows the customer mix and the end users
15 of FEI's commercial customers.
16 So these customers cover a diverse range of
17 natural gas end users, which include restaurants,
18 offices, health care facilities, retail outlets,
19 apartments, and numerous other, as you can see on this
20 customer mix pie chart.
21 In terms of the end use, 85 percent is
22 being used for heating, which means space and water,
23 and 7 percent is for the commercial cooking. And
24 there is a bit more, about 7 percent and 1 percent for
25 appliances and other users.
26 Moving on to slide 71. FEI reviewed the

existing customer segmentation for the commercial customers and, in doing so, it looked at the customer bill frequency, and the load factor analysis. This slide showed the customer bill frequency is basically a plot for the annual consumptions against number of customers as you can see for both small and the large commercial customers on this slide.

Proceeding Time 1:00 p.m. T35

Left chart shows that approximately 72,000, which is 85 percent of the 85,000 small commercial customers, they use less than 600 GJs per year, and almost 99 percent of the small commercial customers use less than 2,000 GJs per year.

On the right-hand side, the chart that shows the large commercial customers, you'll see a fairly large number, approximately 4,600 out of 6,700 customers in total, which is around 69 percent, use between 2,000 GJs per year and 4,000 GJs per year.

So moving to slide 72, this slide shows the load factor distribution of small and large commercial customers. The figures on the chart support the customer segmentation into small and large customers based on the difference in the average load factors for these customer groups. Small commercial customers which is served under rate schedule 2, they have an average load factor of about 31 percent, compared to

the large commercial customers combined rate schedule 3 and 23 have an average load factor of 37 percent. So it's basically a plot against the load factor and the number of the customers.

We do look at another way of reviewing the existing customer segmentation, and how we do that is buy having this plot which is -- we call that a scatter plot, which is basically a plot against the load factor versus the annual consumption.

The chart shows that the commercial customer load factor starts at a low of about 25 percent — that's close to the vertical axis that you see — at around 500 GJs per year level, and increases to about 35 percent, somewhere between 1,000 GJs per year and 2,000 GJs per year, where it remains fairly constant due to the higher levels of annual demand.

Given the load factor differentials, the current threshold of 2,000 GJs per year, that's the current threshold that we have between rate schedule 2 customers and rate schedule 3 and 23 customers. That remains reasonable. However, looking the figure above, one can argue that the threshold is not exactly 2,000 GJs, and can interpret the threshold to be close to, let's say, a thousand GJs.

While differences can be found at other threshold levels, as well as at 2,000 GJs, the result

1 would need to be significantly different to provide a
2 compelling argument to move away from the existing
3 threshold of 2,000 GJs.
4 Next, in slide number 74 -- oh, sorry, we
5 have a question here? Sorry, Tom?
6 MR. HACKNEY: Atul, is there a strong difference in the
7 allocation of cost causality between those smaller
8 groups than the larger group?
9 MR. TOKY: Do you want to --
10 MR. GOSSELIN: Yeah, I'll address that. The cost
11 allocators between the two, because we use load factor
12 to drive a peak day demand, the lower load factor
13 customers tend to create a larger peak day demand for
14 which we use to allocate costs. So the rate 2
15 customers, being marginally lower on a load factor
16 basis than the rate 3 or the small commercial versus
17 the large commercial, attract a few more demand
18 related costs per customer.
19 **Proceeding Time 1:05 p.m. T36**
20 As far as the customer allocations, they're
21 not too different between the two as far as the
22 services and meter factor, and the administration and
23 billing factors, very close as well. So the customer
24 allocations don't change too much, whether you're an
25 RS 2 or a small commercial versus a large commercial.
26 MR. HACKNEY: But Fortis definitely does want to have two

separate classes.

MR. GOSSELIN: Yes, that's -- we believe it's appropriate given that there is a marked difference in the load factor, under about 2,000 GJs.

MR. TOKY: Okay. So, slide number 74. As a part of the review of the existing rate design, FEI looked at the economic cross-over point between rate schedule 2 and rate schedule 3 customers. So what is this economic cross-over point? There is the annual volume at which a customer would have the same annual total cost whether served under rate schedule 2 and 3. So if -- assume if a customer is basically around 2,000 GJs level, so whether that's under rate schedule 2 or 3, would have approximately the same total annual cost. That's the whole idea of the economic cross-over point.

As shown above in this graph, the red line in this graph shows a curve when we plot, when we take the effective rate, which is the dollars per GJ, against the annual consumption for rate schedule 3 customers, which is the large commercial customers, and blue line, it represents rate schedule 2.

As it is clear from the graph, the economic cross-over point when we do this analysis is approximately 1400 GJs per year. Therefore the current rates in these rate schedules, they do provide

1 inappropriate price signals for small commercial
2 customers consuming between 1400 GJs and 2,000 GJs.
3 And the gap that you see, that's what we call as the
4 economic gap, because at 2,000 GJs special level,
5 there is still that much difference. It's not
6 crossing over at that point. Using the existing
7 rates.
8 So we classify this as misalignment in the
9 rates, which gives an incentive to the customers on
10 the rate schedule 2 to consume more energy, so that
11 they can move to 2,000 GJ threshold level, to achieve
12 a lower rate and bill. The misalignment might also
13 cause rate instability for customers whose year-to-
14 year fluctuations in annual demand may occasionally
15 cause them to move back and forth between these rate
16 schedules.
17 In effect, this whole thing causes revenue
18 instability for the utility.
19 So what I'm trying to say here, and point
20 out here is, in our review of the existing customer
21 segmentation and the economic cross-over point that we
22 just looked at, the existing inter-class rate
23 economics for the commercial customers and the
24 customer segmentation threshold are one of the rate
25 design issues that we focused on, and it's focused on
26 in this presentation as well, that they suggest there

is room to improve this alignment using the following rate design principles. So we looked at the fair apportionment of the costs, price signals that encourage efficient use, rate stability, revenue stability, and avoidance of undue discrimination, which is really the inter-class equity.

So in our commercial rate design, we did look at a few of the rate design options. And we also took in consideration the stakeholder workshops and the feedback that we got from those stakeholder workshops last year, in looking at those options.

So option A is to move the threshold between rate schedule 2 and 3 to about 1,000 GJs. Like I said, there is no clear statistical evidence that the threshold really exists at 1,000 GJ mark or 2,000 GJ mark. However, we do have the current existing segmentation threshold at that level.

Proceeding Time 1:10 p.m. T37

If we go with Option A, it results in significant customer disruption by moving customers, which is not supported by rate design principles that we have of rate and revenue stability.

We also looked at Option B, which is moving the threshold between Rate Schedule 2 and Rate Schedule 3 customers to about 1400 GJs. So that's the point where we, if we plot that economic cross-over

1 point, this slide, you see it crosses over at 1400 GJs
2 approximately. So you move the threshold to 1400 GJs.
3 It is still a material change in the customer movement
4 that's causing the customer disruption, and leads to
5 about 600,000 net revenue shift from one customer
6 class, which is like Rate Schedule 3 to Rate Schedule
7 2. And on top of that we don't have any evidence that
8 whether that 1400 GJs threshold is the right threshold
9 or not.
10 Option C is to maintain the existing
11 threshold because we know that's working, of 2,000
12 GJs, but then we have to adjust those basic and
13 delivery charges for these rate schedules to close the
14 economic gap that I just talked about. The advantage
15 of this option is that there is no customer migration,
16 there's less customer disruption.
17 For those on the phone I'm on Slide 76 now
18 which says Commercial Rate Design Proposal. So based
19 on the rate design issues that I just talked about and
20 identified, and potential options available, FEI is
21 proposing to maintain the existing threshold and
22 adjust the basic and delivery charges to close the
23 economic gap. The economic cross-over point can be
24 aligned with the 2000 GJs threshold by simultaneously
25 raising the basic charge for both Rate Schedule 2 and
26 Rate Schedule 3-23 customers, and lowering the

1 delivery charge for Rate Schedule 2 and raising it for
2 Rate Schedule 3 and 23. So those are all the
3 calculations we do in the back to see how we can align
4 those rates back to come to that point where you see
5 these lines now crossed at 2,000 GJ levels, which is
6 the threshold between these two rate schedules.
7 And we will see later on when Rick will go
8 and talk about the revenue-to-cost ratios, that doing
9 with this proposal we are not really changing or
10 disrupting the revenue-to-cost ratios. They continue
11 to be within the range of reasonableness as well.
12 So that's basically what we are doing with
13 our commercial rate design. So we are maintaining the
14 existing threshold of 2,000 GJs between Rate Schedules
15 2 and 3, and we are adjusting Rate Schedule 2 and 3
16 charges to close the economic gap.
17 There are a few things that I didn't
18 include in this presentation but they do apply to the
19 commercial rate design as well. For example, things
20 that Ruth talked about, the rate structure options.
21 So the rate structure that we have currently in place
22 for commercial customers is also a flat rate
23 structure, which we believe for the reasons provided
24 by Ruth also applies to these commercial customers as
25 well. But in a sense this is what we are proposing
26 when it comes to our commercial rate design.

1 That concludes my presentation on the
2 commercial rate design. If there are no questions
3 then we can proceed further. Bill.
4 MR. ANDREWS: Thank you. Bill Andrews. Do you have in
5 the application the revenue/cost ratio consequences of
6 the proposal for change, the basic rate for the
7 commercial customers?
8 MR. TOKY: You mean just the basic charge change or --
9 MR. ANDREWS: Yes.
10 MR. TOKY: -- the combination of those changes that we
11 are proposing?
12 MR. ANDREWS: Well, the combination of maintaining the
13 threshold at 2,000 GJ and changing the basic charges
14 to adjust the cross-over. You were saying that it
15 doesn't have much effect on the revenue-to-cost
16 ratios. I'm just wondering if we would be able to
17 find those in the application.
18 MR. TOKY: Yeah, absolutely. And later on in today's
19 presentation as well, we are going to talk about the
20 revenue-to-cost ratios after all our rate design
21 proposals and how does that look. We did look about
22 the revenue-to-cost ratios in Rick's presentation
23 earlier, before rate design proposals.
24 So we are going to come back and talk,
25 after we make all these rate design proposals, how do
26 the revenue-to-cost ratios look like? And then we are

also going to talk about how the -- if we have to do some rebalancing, that we consider it. If we do that, then what does that do to the revenue-to-cost ratio as well?

MR. ANDREWS: Thanks.

Proceeding Time 1:15 p.m. T38

MR. TOKY: Okay. So now I would like to have Kevin Hodgins, who is our manager, industrial accounts to talk about the industrial rate design.

MR. HODGINS: Hi, everybody. So now we're going to move on into the industrial rate design section. I guess if we move onto the first slide, which is slide 78 here. What you're going to see here is just a summary of the industrial customer characteristics. This first slide is just going to shed some perspective on the industrial customer group as a whole. This section is going to consist of rate schedules 4, rate schedules 5 and 25, 7, 27 and the rate schedule 20s. Rate schedule 22, 22A, 24B as well as the large industrial contracts that we have in place with two customers formerly from the Vancouver Island system.

As you can see on the upper table, this customer, segment of customers, represents almost a thousand customers and about 70 petajoules of annual gas consumption across the whole group. The major

gas consuming industries within this group are the pulp and paper, wood products, oil and gas manufacturing and greenhouse sectors. Across the category as well, there's five primary end uses, boilers, product drying, process heating, industrial processes and space heating.

As we move onto the next slide, slide number 79, this is going to give a summary of my overall agenda for industrial rate design and the different rate schedules that I'll be going through today.

On slide 80, what you can see here is the bill frequency for rate schedules 5 and 25 customers. So this is going to provide a quick snapshot for the nearly 800 customers that are in these combined rate schedules. Rate schedule 5 is a sales service, so it's the delivery as well as the commodity is provided under this rate schedule, and rate schedule 25 is the transportation equivalent of rate schedule 5. So customers under all the rate schedule 20s that I'll discuss today utilize a gas marketer or a shipper agent to provide their commodity on their system for them.

As you can see from this graph it shows that the majority of customers within these rate classes use between 5,000 and 25,000 gigajoules per

1 year, but some may use up to about 150,000 gigajoules
2 or slightly more.
3 On slide number 81, we're just going to
4 look at the current rate structure that's in place
5 with these rate classes. So at FEI's general firm
6 service for rate schedule 5 and 25, it's designed to
7 serve high load factor and process load customers that
8 have an efficient utilization of our system. So in
9 addition to a basic charge per month, and a variable
10 delivery charge, the rate structure also includes a
11 demand change. And this demand charge helps us
12 recover the allocated cost of service in a way that
13 reflects each customer's load profile and demand on
14 the system.
15 The rate schedule 5 and 25 rate structure
16 is designed to utilize a demand charge which can
17 provide lower average rates to these higher load
18 factor customers.
19 Additionally you can see that the rate
20 schedule 25 rate class does also have an
21 administration charge per month of $78, and this is
22 associated with the provision of the transportation
23 service.
24 Overall FEI finds that this existing rate
25 structure is working well, as intended.
26 On slide number 82, we are now looking at

1 the existing rate design review for rate schedules 5
2 and 25. Upon reviewing the existing design, FEI
3 concluded that generally these rate schedules are
4 working as designed. However, we did identify two
5 areas of interest that we wanted to investigate.
6 The first area was with respect to the
7 daily demand formula that is associated with the
8 demand charge. For the majority of customers FEI
9 found that the current method of determining our
10 customer's daily demand overstated the customer's peak
11 demand on the system -- or sorry, overestimated the
12 customer's peak demand on the system.
13 **Proceeding Time 1:21 p.m. T39**
14 Overestimating the demand may not result in
15 fair apportionment of costs among customers in rate
16 schedules 5 and 25, and may distort the price signals
17 for efficient use of the system which is intended by
18 the rate structure.
19 The second area of interest is with respect
20 to maintaining the proper price signals. So the
21 existing rate structures was designed to provide an
22 incentive for high load factor customers to receive
23 service under rate schedule 5 and 25, and we want that
24 to be maintained.
25 As we move on to slide number 83, on this
26 slide, FEI reviewed current methodology that's in

place right now for calculating the daily demand. We also reviewed four other methods. The first method that we reviewed is obviously our current formula, which we found overstates a customer's peak demand on the system.

The second method we looked at would be to continue to use the existing formula, but update the multiplier in the formula that aligns more closely with the peak demand of the customer group on the five coldest days of the year.

The third method we investigated was to look at actually using customers' daily consumption on our maximum day send-out. So what was the day within the previous year that was our highest deliverable requirement from the system?

Under the fourth method that we looked at, we also looked at what would the customer's daily averaged consumption be over the peak weather conditions, or peak days on the system? So we'd look back at what were their consumption on the three or five coldest days for their weather region within the province.

And the last method that we investigated was looking at -- was similar to method 4, where we looked at what their consumption was on the five coldest days in their region, or half of their average

consumption of any month during the summer period. So that last method is somewhat similar to our current formula, but we are actually looking at customer-specific consumption on the coldest-type days.

Yeah?

MR. HACKNEY: Does there --

MR. HODGINS: One sec, here comes the microphone.

MR. HACKNEY: Okay. Does there exist, or might there soon be gas meters that actually measure peak demand?

MR. HODGINS: Yes. So all these customers do -- once they move into certain rate classes, that are rate schedules 5, 25, and up through the 20s, and 7-27, all of those rate classes require an automated meter reader, they call it. Basically a device that reads the data and phones in daily consumption figures to us.

MR. HACKNEY: So that should directly -- by direct measurement, give you the peak consumption.

MR. HODGINS: Yes, we can get the -- from the data on a customer-specific basis, we can get their actual consumption on a daily basis. But it doesn't necessarily align with what -- their peak consumption doesn't necessarily align with their consumption on a peak day. Which is --

MR. HACKNEY: Oh, coincident peak.

MR. HODGINS: Yes, a coincident peak, yes.

1 MR. HACKNEY: With other customers.
2 MR. HODGINS: Yeah.
3 MR. HACKNEY: Okay. Thank you.
4 MR. HODGINS: If we move on to slide 84. Through our
5 evaluation of the daily demand methods, FEI found that
6 option 2, or method 2, seemed to strike the best
7 balance between better alignment of an estimated
8 coincident peak demand and a high level of customer
9 understanding of how the rates would be applied. We
10 found this option will also provide more rate and
11 revenue stability, producing fewer anomalous results.
12 Other than the adjustment to the
13 multiplier, this method uses the current formula,
14 which has been around for many years and is understood
15 by the customers.
16 **Proceeding Time 1:26 p.m. T40**
17 This rate calculation is understandable and
18 it's easy to implement. This method also reduces
19 potential anomalous results that could understate or
20 not be representative of a customer's peak demand.
21 Anomalous results could be substantive from the
22 reduced demand on Sundays, statutory holidays, or
23 short-term seasonal holidays such as the Christmas-New
24 Year period when some customers would have reduced
25 operations.
26 By maintaining the formula and not

1 requiring daily consumption figures for every customer
2 to calculate their peak demand within the formula, new
3 customers to this rate class that do not yet have
4 daily metering can still determine whether there is a
5 benefit in moving into this rate schedule.
6 For all those reasons, FEI proposes to
7 maintain the current formula but update the
8 multiplier.
9 As we move onto slide 85. This slide is
10 about the price signal options and so this is the
11 second area of interest that FEI wanted to
12 investigation with respect to rate schedules 5 and 25.
13 FEI has considered the following four
14 options to ensure that there is an appropriate
15 economic incentive for lower load factor customers to
16 continue to take service under our rate schedules 3 or
17 23 rather than under rate schedule 5 or 25, which is
18 designed for a higher load factor customer.
19 So the four options we were looking at were
20 if we investigated changing the basic charge, changing
21 the variable delivery charge. We also investigated
22 removing the demand charge which was suggested at one
23 of our workshops by some of the stakeholders, or just
24 changing the demand charge.
25 Of these options listed above, FEI found
26 that the best mechanism to provide an incentive for

1 customers whose load factor is less than 40 percent,
2 to take service under rate schedule 3 or 23 rather
3 than rate schedule 5/25 was to maintain the demand
4 charge and increase the demand charge as a result of
5 the change to the formula we proposed for daily
6 demand.
7 As we move onto slide 86, this slide is our
8 proposal for rate schedules 5 and 25, and to summarize
9 what I've just kind of stated, FEI is proposing to
10 maintain the current rate structure for rate schedule
11 5/25 but make two adjustments. We are proposing to
12 update the multiplier from 1.25 to 1.1 that is used in
13 the current method to determine the daily demand as an
14 estimate of the customer's peak demand. This change
15 is proposed to more accurately estimate the peak daily
16 demand for the purposes of the demand charge
17 calculation.
18 FEI is also proposing to increase the
19 demand charge by $3. This change is proposed to
20 continue the incentive for low load factor customers
21 to take service under large commercial rate schedules
22 3 and 23 rather than general firm service 5/25 which
23 is intended for higher load factor customers.
24 So no questions, I'll move onto the next
25 slide and the next rate schedule.
26 On slide 87 now. We're moving onto rate

1 schedules 7 and 27. And again rate schedule 7 is
2 sales bundled service and rate schedule 27 is the
3 transport equivalent of that rate schedule. And this
4 is small volume interruptible service.
5 So you can see here is the bill frequency
6 for the rate 7 and 27 customer group. FEI currently
7 has just over 100 customers served under general
8 interruptible service.
9 **Proceeding Time 1:31 p.m. T41**
10 It includes a wide range of industries such
11 as asphalt plants, greenhouses, hospitals, sawmills,
12 and numerous other industries. These customers use an
13 average around 59,000 gigajoules per year. The annual
14 bill frequency shows that the annual consumption from
15 these customers ranges from about 5,000 to 150,000
16 GJs, so a broad spectrum.
17 As we move on to Slide number 88 now, this
18 slide shows the rate structure and a review of the
19 rate structure for Rates 7 and 27. The rate structure
20 for interruptible sales and transport service includes
21 a monthly basic charge and a volumetric delivery
22 charge. And as previously indicated for Rate Schedule
23 25, the transportation equivalent Rate Schedule 27
24 also has an additional administrative charge per month
25 of $78.
26 As we move on to Slide 89 we're going to

1 move on to our proposal. So to encourage existing
2 customers to remain on interruptible service and
3 attract new interruptible customers, Rate Schedules 7
4 and 27 charges are set at a discount to Rate Schedules
5 5-25 general firm service. From the customer's
6 perspective, the economic decision to take firm or
7 interruptible service is dependent on whether the
8 discount from firm is sufficient to compensate for the
9 cost to have an alternate backup system and fuel costs
10 that can be used for the costs from ceasing operations
11 when they're restricted and they're interrupted.
12 Setting the discount either too high or too
13 low would send the wrong price signals and could cause
14 the rate and revenue instability for customers and
15 FEI. If the discount is too low, this may discourage
16 new customers from considering interruptible service,
17 and they also cause existing interruptible customers
18 to migrate to firm service. If the discount is too
19 high, too many customers with firm service may elect
20 to contract for interruptible service.
21 FEI believes that the discount is working
22 well as FEI has experienced no unusual or
23 unanticipated migration activity from firm to
24 interruptible, or the other way from interruptible to
25 firm. And that would suggest that the rates or rate
26 structures are produced -- that the rate structures

are not producing undesirable effects on the customer service option selections.

The discount from firm service under the existing Rate Schedules 7 and 27 interruptible service charges achieves a reasonable balance between maximizing the economic value of interruptible service, which helps offset utility cost to firm customers and providing a sufficient incentive for existing customers to stay on interruptible service, as well as attracting potential new customers.

FEI is therefore proposing to retain the current interruptible service rate structure and the method of calculating the Rate 7 and 27 delivery charges, based on a discount from Rate Schedules 5 and 25. FEI is proposing though to update the Rate 7 and 27 delivery charge calculation to reflect changes in the daily demand formula that we proposed under Rate Schedule 5 and 25 -- sorry, to maintain the current approximate 18 percent discount.

Yeah, Suzanne?

MS. SUE: Suzanne Sue. I'd just like to find out often have the interruptible customers been interrupted on average over the last five or ten years?

MR. HODGINS: Historically looking back, we've curtailed or interrupted the customers, it averages about one day per year.

1 MS. SUE: Thank you.
2 MR. HODGINS: Yeah.
3 MR. WEAFER: Just following up on that. Sorry, Chris
4 Weafer, Commercial Energy Consumers.
5 MR. HODGINS: Yeah.
6 MR. WEAFER: Is the interruptibility weather related or
7 facility repair related?
8 **Proceeding Time 1:36 p.m. T42**
9 MR. HODGINS: When I'm talking about the one day per
10 year, that's usually weather related. So we model
11 within our system at a certain degree day in advance
12 of getting to the peak design conditions, all
13 interruptible customers are off the system, but
14 interruptible rate schedules also provide us the
15 benefit of we can interrupt them for operational
16 reasons, if there's line hits in a certain area. So
17 there's the additional benefits or even during
18 maintenance we can interrupt customers as well.
19 MR. WEAFER: But the one day a year is weather related.
20 MR. HODGINS: It's weather related yes.
21 MR. WEAFER: It's an average. So it could have been five
22 in one year, or ten in one year.
23 MR. HODGINS: Yeah.
24 MR. WEAFER: That's your average. Okay, thank you.
25 MR. HODGINS: Yes. No other questions? Okay.
26 So now we can move onto rate schedule 4.

1 So rate schedule 4 serves the unique needs or
2 approximately 20 of our seasonal customers who
3 typically do not use natural gas during the winter and
4 thus do not contribute to FEI's system peak demand.
5 Rate 4 customers are typically the outdoor pools that
6 we see around our communities, or some of the asphalt
7 paving companies in the Interior, because they don't
8 pave during cold weather.
9 B.C.'s load customers usually use gas
10 primarily during the off peak or summer period from
11 April through October. However, some seasonal
12 customers may also use gas in the months of November
13 and March when there is still available capacity and
14 gas supply. During the coldest months from December
15 through February seasonal customers do not usually
16 take any gas service.
17 During the off peak or summer periods
18 seasonal customers receive firm sales service and the
19 delivery charges are derived from rate schedules 5 and
20 25. During the extension period or winter period
21 seasonal customers can receive only interruptible
22 sales service. In order to provide service to rate
23 schedule 4 customers during the extension period, FEI
24 must have sufficient supply of gas and capacity to
25 deliver gas to them.
26 For the extension period, the rate schedule

4 delivery charge is derived from interruptible rate schedules 7/27 delivery charges. For seasonal customers FEI is proposing to maintain the existing rate structures and methodology to derive the rate schedule for delivery charges. Since the rate schedule for delivery charges are based on rate schedules 5 and 25 as well as rate schedules 7/27, FEI is proposing just to update the rate schedule 4 delivery charges to reflect the proposed changes discussed within rate schedule 5/25 and rate schedule 7 and 27.

Next slide. We are on slide 91 now. So last subset of the industrial group I'm going to talk about now is the rate schedule 20s and our large contract customers.

FEI's large volume industrial transportation customers are currently segmented into four groups. Rate schedule 22, rate schedule 22A, 22B and the large industrial contract customers which consist of the Vancouver Island joint venture, which is a group of pulp mills, and the BC Hydro Island generation facility.

These four groups are the legacy of the service area of FEI's predecessor company, with rate schedule 22 customers being located primarily in the Lower Mainland, the rate schedule 22A customers in the

1 Inland service area, 22B customers in the Columbia
2 service area, and the two large industrial contract
3 customers located on Vancouver Island and Sunshine
4 Coast.
5 Yes?
6 MR. WEAFER: Chris Weafer, Commercial Energy Consumers.
7 Where do the bypass customers fit in on any of those?
8 Are they in 22A or 22B or are they separate from that?
9 22A and 22B I think are closed schedules for the
10 Inland territory, but do they include the bypass
11 customer?
12 **Proceeding Time 1:41 p.m. T43**
13 MR. HODGINS: Okay, the bypass customers that we have,
14 there is -- they're under a rate 22A bypass. We have
15 rate schedule 22 bypass. And there is also some rate
16 schedule 25 bypass customers.
17 MR. WEAFER: So do these numbers include the bypass
18 customers? Or are they --
19 MR. HODGINS: They do not.
20 MR. WEAFER: And so -- I don't want to go into detail on
21 it, so how many bypass customers are there and what
22 kind of volumes would they -- as annual demand? In
23 rough numbers.
24 MR. PERTTULA: I got that.
25 MR. HODGINS: Do you have it?
26 MR. GOSSELIN: We have -- sorry.

1 MR. HODGINS: Dave wants to.
2 MR. GOSSELIN: Oh, Dave? Could you get that? Go ahead,
3 Dave.
4 MR. PERTTULA: There are ten bypass customers.
5 MR. WEAFER: And rough volume.
6 MR. HODGINS: They take about nine PJs per year.
7 MR. WEAFER: Thank you.
8 MR. PERTTULA: There is one other customer that's
9 technically not a bypass customer but has a special
10 contract, and that's sometimes grouped with the bypass
11 customers in our applications, but that's a coal mine
12 in the Columbia service area. So it technically isn't
13 a bypass customer but it does have a special contract.
14 MR. HODGINS: And they're served off their own dedicated
15 lateral.
16 MR. PERTTULA: Right.
17 MR. WEAFER: And, not to bog this discussion down, but
18 there is not a lot in the application about the bypass
19 customers in -- is it possible to give a general
20 description now, and why they continue on as bypass
21 customers?
22 MR. HODGINS: Sure.
23 MR. PERTTULA: Yeah, so this is a concept that developed
24 in the late 1980s as the gas markets were undergoing
25 deregulation. And it pertains to industrial customers
26 for the most part that are very close to the upstream

1 pipeline. So in our case they're close to the
2 WestCoast transmission line, or the Spectra line. And
3 so they had the -- a real opportunity to construct
4 their own line to the upstream transmission line, and
5 bypass the utility's distribution system.
6 So, rather than having those physical
7 bypasses take place, there were processes sponsored
8 basically by an Order in Council from the government,
9 but also BCUC hearings, that determined that it would
10 be better to have an acceptable negotiated rate that
11 was close to their competitive bypass rate, had they
12 built their own line. It would be better to have
13 those revenues coming from those customers rather than
14 lose them all together and actually have them do a
15 physical bypass of the utility system.
16 So, those contracts remain in place.
17 They're still viable bypass threats, if we were to,
18 you know, to reopen them and try to increase those
19 rates. They would, you know -- they would have the
20 opportunity to actually pursue a physical bypass of
21 the system. So that's still the same as the way
22 things were in the late 1980s. And so we don't want
23 -- we don't see any good reason to reopen those, or to
24 make that an issue in the proceeding here.
25 So is that --
26 MR. WEAFER: Yeah, that's helpful. (inaudible).

MR. PERTTULA: Okay.
MR. ANDREWS: If I could just follow up on that.
MR. PERTTULA: Yeah.
MR. ANDREWS: You're saying that these bypass customers are still in a position to have the opportunity to do a bypass. Do you have reason to believe that the costs to them, their opportunity cost, is still the way it was when these contracts were first entered into? So that the terms of those contracts go -- make the same financial sense to FEI?
MR. PERTTULA: The contracts do have some elements that escalate over time. So, for example, there is an allowance for operating and maintenance costs in the contracts. And those -- those have been escalating over time.

Proceeding Time 1:46 p.m. T44

So, you know, the costs are probably similar to what they might experience today, but we haven't actually done an analysis to say that the bypass costs are the same as what they were when those contracts were originally established.
MR. BYSTROM: Chris Bystrom, for Fortis. I just might add a little colour, that the contracts are designed so that they continue to reflect what the bypass customer would pay if they had actually constructed and were operating their own pipeline. So they're all

1 worded so that there is adjustment so that, you know,
2 if they had to add new facilities to serve an
3 increased volume or capacity that you required, then
4 the charges are adjusted to reflect that.
5 So, in principle, those agreements are such
6 that they continue to reflect what they would have --
7 would be paying if they had actually constructed their
8 own pipeline.
9 MR. ANDREWS: Thank you.
10 MR. TOKY: Do you want to say something?
11 THE CHAIRPERSON: I have a question on the interruptible
12 rate.
13 MR. TOKY: Yes.
14 THE CHAIRPERSON: Earlier in the presentation there was
15 reference to the Lower Mainland intermediate pressure
16 replacement. Does that impact the capacity at all and
17 the need for an interruptible rate to make peak day
18 demand?
19 MR. GOSSELIN: If I recall the application was about
20 system resiliency. To the most extensive -- we have
21 the Lower Mainland that was basically fed through one
22 point of entry, I believe. I'm trying to think back
23 to the application itself. But it was generally about
24 system resiliency in the Lower Mainland. And it was
25 -- that was the premise upon which some of the -- or,
26 the CPCN -- I'm not sure about all the approvals in

1 the CPCN on that, but that one I recall. It was about
2 resiliency and now so much about the capacity.
3 THE CHAIRPERSON: Thank you.
4 MR. TOKY: Okay.
5 MR. HODGINS: Sorry, I'm just catching up to where I was.
6 So back on slide 91. Rate schedule 22A and
7 22B classes have been closed to any new customers
8 since 1993. Since that time, any new large industrial
9 transportation customers for FEI have taken service
10 through rate schedule 22.
11 And moving on now to slide number 92. When
12 reviewing the rate design, FEI considered three main
13 points. The first one was whether we can look at
14 minimizing regional differences in this group of
15 customers. The second, that we had to consider the
16 timing and end dates of the large contracts in place
17 with the Vancouver Island joint venture and BC Hydro.
18 As well as, these existing contracts had
19 not been adjusted as a result of the amalgamation of
20 Vancouver Island Utility. And the last point that we
21 considered when looking at our options for this group
22 of customers is that FEI needed to review the firm
23 rate methodology for rate schedule 22.
24 Rate schedule 22 is primarily an
25 interruptible service, but firm rates can be approved
26 or negotiated and then approved by the Utilities

1 Commission. Currently we have one customer under rate
2 schedule 22 that was receiving firm service, and
3 that's Creative Energy or the central heat
4 distribution system here downtown. And when that firm
5 rate was approved by the BCUC, we were also directed
6 to review the firm rate design in our next rate design
7 process. We have also had other Rate 22 customers
8 express interest in some firm capacity for a portion
9 of their overall load.
10 So we'll move on to slide 93.
11 **Proceeding Time 1:51 p.m. T45**
12 Based on the review of the existing rate
13 design of large volume transportation customers, FEI
14 considered two options. The first option is status
15 quo, essentially. Under this option schedules 22A and
16 22B would remain closed rate schedules. We would also
17 look to determine a firm rate for rate schedule 22 and
18 set interruptible rates that would be based on a value
19 of service rather than cost basis.
20 We would also look to maintain separate
21 contract rates in place for the Vancouver Island joint
22 venture and BC Hydro. The second option that we
23 considered would be fore 22A and 22B to remain
24 grandfathered in closed rate schedules as well. But
25 we look to determine a postage stamp cost of service
26 rate which would establish both firm and interruptible

1 rates for rate schedule 22 that are cost based and
2 applicable to all large industrial customers including
3 Creative Energy, the Vancouver Island Joint Venture,
4 and BC Hydro.
5 So we move onto slide 94. This would be
6 our large volume transportation and contract customers
7 rate design proposal. FEI's proposal is option 2.
8 FEI is proposing a rate design for large volume
9 transportation customers that continues to grandfather
10 rate schedules 22A and B as closed service offerings
11 and creates a postage stamp cost of service based rate
12 with firm rates for all other large industrial
13 customers including Creative Energy, the Joint Venture
14 and BC Hydro.
15 Under this option, the rates for
16 interruptible service would be set equal to the firm
17 rates, however the firm rates have been converted into
18 a combination of a firm demand charge and variable
19 delivery charge similar to what you've seen under rate
20 schedules 5 and 25 and are also within rate schedules
21 22A and 22B.
22 BC Hydro's Island Generation contract would
23 continue to take service under its existing agreement
24 which continues until April of 2022 at their current
25 rate. After the contract expires, BC Hydro could
26 choose to become a rate schedule 22 customer.

Yes.

MS. BRAITHWAITE: Do you have the comparable figures for rate schedule 22A and 22B as are shown for rate schedule 22 on slide 94?

MR. GOSSELIN: No, not at hand.

MR. HODGINS: Yeah, sorry, I don't have them. Yeah. They are all laid out, I know, in the application. Is that okay?

We move to my last slide, slide 95. This last slide is just a summary of the industrial rate design proposals that we've ran through, and just to summarize it again. For rate schedule 5 and 25 we are proposing to maintain the current formula with an updated multiplier of 1.1 for the daily demand calculation, as well as raise the demand charge by $3.00 per month per gigajoule of daily demand.

For rate schedule 7/27 we are proposing to maintain the existing rate structure but adjust the resulting rates and delivery charge calculations to reflect proposed changes in rate schedule 5 and 25 maintain the approximate 18 percent discount firm that there is today.

Proceeding Time 1:56 p.m. T46

For rate schedule 4, we're proposing to maintain the existing rate setting methodologies and update the rates due to changes to rate schedule 5/25

1 and 7/27. And finally for the rate schedules 22, 22A,
2 B and the large contract customers, we're proposing to
3 maintain 22A and 22B as closed rate schedules,
4 calculate a single rate 22 firm rate based on the
5 allocated costs in the COSA for rate 22, the Joint
6 Venture and BC Hydro together as a group.
7 Yes?
8 MR. WEAFER: Chris Weafer, Commercial Energy Consumers.
9 For rate schedule 22, what's the interruption
10 experience with that group in the last few years?
11 MR. HODGINS: It's the same curtailment that we talked
12 about for interruptible. So it averages the one day
13 per year. In the last few years, we haven't had any
14 curtailment. We've gotten close. Even this last past
15 winter we didn't have any curtailment other than some
16 localized areas on our system where we did interrupt a
17 few customers for capacity. Or there's a group of
18 greenhouses on our system where we work with them and
19 they load shift to get off on our morning peak.
20 MR. WEAFER: The opportunity in the rate design is now
21 for them to be able to buy out of that interruption
22 with -- the element of firm service would be able to
23 avoid that one day a year on average they're
24 interrupted. Is that the proposal?
25 MR. HODGINS: The element of firm service is that some
26 of them -- they want a portion of their load. So when

1 we look at curtailing them, it's a portion. So in
2 areas where we do have capacity and we aren't capacity
3 constrained, if they want to elect firm service, we
4 would sell that so we could get more revenue from them
5 on those days when would normally be curtailing them
6 and they have to get fully off the system.
7 MR. WEAFER: I understand. So you're not interrupting
8 their peak, you are leaving them with a base load?
9 MR. HODGINS: Yeah, they would drop down to some sort of
10 base amount.
11 MR. WEAFER: Thank you, that's helpful.
12 MR. HODGINS: Any other questions?
13 MR. TOKY: I just have one comment, just to reply to
14 what Tannis was mentioning earlier. So there is a
15 table 9-23 in the application page 9-40, that does
16 show those rates for the rate 22As and Bs.
17 MR. HODGINS: All right.
18 MR. MARTISKAINEN: One more quick question on the
19 curtailment or interruptible versus firm. So again, I
20 guess more than once per year let's say folks are
21 knocked down to their firm. Is there a statistic or
22 an average, last two years, last five years on that
23 occurrence?
24 MR. HODGINS: No, and it becomes site specific. So --
25 yeah, no there's not a statistic on those numbers.
26 All right, thank you. I'll like to pass it

1 onto Stephanie Salbach for the next section.
2 MS. SALBACH: Hi there. Thank you, Kevin, and I'm the
3 transportation services manager and energy supply at
4 Fortis. In the following slides I'll review the
5 proposed changes in the transportation model as
6 included in the rate design application.
7 Before I get into the proposed changes, I
8 wanted to quickly put this slide up, which was very
9 similar to what was presented last week. I feel it
10 provides a key understanding of the daily load
11 balancing functions relative to the changes we're
12 proposing to review today.
13 As depicted here, FEI is responsible for
14 managing the system as a whole, which includes daily
15 system business from sales and transportation
16 customers. The total supply that is received at FEI's
17 interconnects from all sources and the total system
18 demand must be balanced between the interconnecting
19 pipelines. The main point I wanted to make on this
20 slide was that on a daily basis system imbalances
21 between both supply and demand from both sales and
22 transportation customers is managed by storage and
23 transportation resources that are under -- that are
24 classified as midstream resources, and these are borne
25 and paid for by sales customers.
26 **Proceeding Time 2:01 p.m. T47**

As a result of the overall daily balancing activities from FEI and a flexible balancing tolerance that exists today, transportation customers effectively receive a benefit for these services. The consideration of this benefit, as well as other factors and analysis, have led us to focus on a few areas of the model.

Generally FEI feels the business model for the transportation service area of the business to be working well. As the model was developed several years ago, FEI is proposing a few changes to reflect current day practices, as well as general changes in the industry. The three listed here are the main areas FEI is proposing to make changes. The first deals with the daily and monthly balancing options that are in place today, and the second and third deal with the balancing tolerance, as well as the charges for these balancing tolerances today.

So the first area that we looked at, as I mentioned, is the balancing provision. FEI currently allows customers to be either daily or monthly balanced, with the exception of Rate 22 customers, which much be balanced daily. There are charges and balancing tolerances in place for daily balanced customers to incent daily balancing, whereas there are no charges nor balancing tolerances on the day to

1 provide the same incentive for monthly balanced
2 customers. Given this, monthly balanced customers
3 have the ability to draft or undersupply on a daily
4 basis through the month.
5 Given these current provisions, FEI looked
6 at three options. The first one as indicated here is
7 to maintain the status quo, which would effectively
8 leave daily and monthly balancing provisions in place
9 as they are today. If no changes were made to the
10 model, an uneven playing field would continue to exist
11 between daily and monthly balanced customers. This
12 option effectively would fail to address the directive
13 that was given by the Commission to FEI from the
14 monthly balancing gas application from 2014. This
15 directive stated that FEI derived an appropriate rate
16 design mechanism to incent the appropriate behaviour
17 not just at month end but during the month as well.
18 Given these reasons, FEI is not in favour of Option 1.
19 Option 2 retains monthly balancing
20 practices but with an increased charge for customers.
21 This approach may -- we felt this approach may also
22 not satisfy the Commission directive for monthly
23 balance customers to balance throughout the month, not
24 just by month end. Furthermore, research indicates
25 that monthly balancing is not consistent with industry
26 practice. In light of these items, FEI is not in

1 favour of this option.
2 Which leads me to Option 3. This option
3 involves moving all customers in all service territory
4 to daily balancing exclusively. Based on the
5 principle of fairness, this option would treat all
6 customers and marketers equally. As compared to when
7 the transportation model was developed, transportation
8 customers or their marketers have the tools today to
9 amend gas requirements on the day to reflect changes
10 in load. Many of our customers today -- marketers I
11 should say, hold daily balanced groups exclusively
12 today. And as I mentioned, the larger Rate 22
13 customers on our system already adhere to daily
14 balancing provisions today. FEI itself is held to
15 daily balancing provisions with our upstream
16 interconnecting pipelines, and research indicates that
17 daily balancing is consistent with general industry
18 practice.
19 So in sum, in the interests of fairness and
20 the reasons I just listed, FEI proposes to eliminate
21 monthly balancing and require all transportation
22 customers to balance daily.
23 The second area we looked at is the
24 balancing tolerance and charges. As I reviewed last
25 week, the balancing tolerance we have today is 20
26 percent and the charges are, when under-deliveries

exceed 20 percent, in the summer the charge is 30 cents per GJ and in the winter it's $1.10 per GJ for under-deliveries. As I mentioned earlier, system imbalances borne by the transportation customers are managed under the annual contracting plan by the midstream resources. Given this benefit, we felt it was reasonable to evaluate a fee to account for this balancing service that's provided. This is Option 1.

Black & Veatch assisted us in calculating the replacement cost of the balancing services under various bandwidths provided by FEI. Under this option, the fee for this balancing service would be applied to all customers on a per GJ basis of throughput to account for the balancing service. If this option was implemented, FEI felt it would effectively penalize marketers that are operating within reasonable balancing tolerances today.

And furthermore FEI feels that if a fee-based approach were implemented, this would not provide an incentive to the customers or marketers to manage supply and demand more closely, which is a fundamental obligation in our rate schedules today.

Proceeding Time 2:07 p.m. T48

Option 1, we feel, would fundamentally change the model, and for these reasons FEI is not proposing a balancing fee as such.

Instead of a fee, FEI evaluated the idea of tightening the balancing threshold currently in place. Under option 2, it was identified with the research of Black ^ Veatch that our current threshold of 20 percent is very lenient compared to other local distribution companies. Under this option of imposing a tighter bandwidth, FEI would continue to balance the system as a whole. However, by tightening this tolerance, marketers would be incented to manage their customer load more closely and effectively reduce large fluctuations, swings, that are experienced today.

So, having said that, what should the tolerance be? We considered a 5 percent tolerance, but determined this would be too stringent, given that FEI currently can impose a 5 percent tolerance under supply restriction circumstances today. So, based on the analysis that we undertook, we looked at the balancing activities by our transportation customers in the years 2014 and 2015, and identified that a large number of marketers today manage their business substantially within a ten percent tolerance.

Based on this, FEI is proposing to reduce the balancing tolerance threshold from 20 to 10 percent to be applied to all customers.

So, if we were to reduce this tolerance to

10 percent, what should the associated balancing charges be? As seen in the first table, FEI looked at the variable incremental costs involved in system balancing. The variable costs were calculated based on the commodity charge, pipeline fuel, and storage fuel. FEI considered the potential charge for a range of commodity prices as depicted here, from $2.50 to $5 US per MMBTU, and the resulting variable costs ranged, as you can see here, from 20 cents to 33 cents.

Based on this range of incremental variable costs, FEI is proposing to apply a mid-range charge of 25 cents for the 10 to 20 percent range, which would be applied in both the summer and winter months.

Now, to note, I've listed the range of costs that we undertook in our evaluation. I just wanted to make a note that should the cost of gas exceed $5 per MMBTU, which is the highest value listed here, FEI would apply to the Commission to update this charge.

So as seen in the second table, the balancing within a zero to 10 percent range, FEI is not proposing a balancing fee. For the 10 to 20 percent range, as I mentioned, we would apply a 25 cent balancing fee in both the summer and winter months. And for the 20 percent plus range, FEI is proposing to retain the current charges that are in

place today, which is $1.10 in the winter and 30 cents in the summer.

So, in summary, FEI is proposing in the rate design application to eliminate monthly balancing provisions entirely for the transportation services model, and require that all the customers in all service territories to balance daily. And secondly, we would like to amend the balancing tolerance from 20 to 10 percent, and implement a tiered charge approach whereby charges would increase as tolerance ranges are exceeded.

Welcome to take any questions anybody might have.

Well, that's great. Thank you very much for your time and attention.

MR. TOKY: So, just checking in. Before we go into the rebalancing and the final COSA results, which would be taking into consideration all the rate design proposals that we have made, we can either now take a short break, maybe a ten-minute break, and then come back and go through these. Depends on how everyone is feeling. I just want to be very -- you know, open for that. So whatever --

THE CHAIRPERSON: Let's take a break.

MR. TOKY: You want to take a break?

THE CHAIRPERSON: Sure.

1 MR. TOKY: Perfect. So we'll take a ten minute break.
2 Be back here at 2:25.
3 **(PROCEEDINGS ADJOURNED AT 2:12 P.M.)**
4 **(PROCEEDINGS RESUMED AT 2:25 P.M.) T49/50**
5 MR. GOSSELIN: All right, thanks, folks. The next couple
6 of slides we're going to talk about the rebalancing
7 and the final COSA results.
8 So FEI allocates its costs in its COSA
9 model and then that COSA model helps inform the
10 subsequent rate design proposals as we've just
11 discussed over the last couple of hours.
12 The rate design proposals affect some of
13 the cost allocations and revenues within the COSA.
14 These adjustments are summarized in section 12.1 of
15 the application.
16 I'll summarize those adjustments based on
17 the rate design proposals through some texts here --
18 or words, rather. So rate schedule 2, 3 and 23. We
19 had our commercial rate design proposal which was
20 basically resetting the rates so that the economic
21 threshold is reset to 2,000 gigajoules per year. This
22 creates a revenue shift of about 1.2 million from rate
23 schedule 2 to rate schedule 3/23. There is no cost
24 implications to it, meaning it doesn't change the way
25 costs are allocated in the COSA.
26 For rate schedule 5/25, Kevin talked about

1 resetting -- or sorry, changing the factor that we
2 used to set the contract demand from 1.25 to 1.1 and
3 also increasing the demand charge by $3.00. This has
4 no cost allocation consequences in the COSA either.
5 However, it does increase the revenue from rate
6 schedule 5/25 by a small amount of $45,000 for all of
7 the customers in total.
8 Rate 7/27, Kevin talked about basically the
9 trickledown effect of changing 5/25 and its affect on
10 7/27. Based on the proposals FEI has in the rate
11 design application, we see a small decrease from the
12 rate 7/27 customers of $91,000 in total.
13 And then rate 4 again is a trickledown
14 effect from changing both rate schedules 5 and 25 and
15 7 and 27, and rate 4 will see a small increase of
16 about $13,000 for that rate schedule in total.
17 So none of these changes that I just spoke
18 of have any impact on cost allocation in the COSA
19 model.
20 And then we have our rate schedule 22 firm
21 industrial proposal. This has an affect on the cost
22 allocations in the COSA and why it does that is
23 because we have a 60 TJs per day for these customers
24 that we're using to allocate cost to that rate
25 schedule, that firm offering, and so it has a small
26 change in the way costs are allocated in the COSA.

Not big ones, but just a little small shift in the way costs are allocated.

The resulting revenue change to the utility as a whole from the rate schedule 22 firm proposal is a decrease in revenues of about $754,000. That takes into account the fact that BC Hydro is going to -- BC Hydro IT is going to retain their contract until 2022.

So the sum of all these, the net sum of all these rate design proposals comes to a net decrease of about $786,000 in revenue for the utility to cover its cost. So what we do in the COSA is we shift that $786,000 to rate schedule 1. Rate schedule 1 is currently the only rate schedule that is under 100, or it's got the lowest RC ratios, so we shift that to the rate schedule 1 as a pick up in revenue from them. And so the results of that COSA, COSA after rate design proposals, you can see in the first two columns of the table you have up on the screen.

Proceeding Time 2:30 p.m. T51

It's labelled "COSA after rate design proposals".

As you can see, rate schedules -- most of the rate schedules shown there fall within the 90 to 110 range of reasonableness that the utility is using as its guidelines, and then from there we look at the rate schedule and we decide if any of them need to be rebalanced.

So in looking at it, rate schedule 6/6P falls quite outside the range of 90 to 110 and so we are proposing a rebalancing for this rate schedule of $61,000 to bring them down into line at 110 RC ratio. This 61,000 we would shift over to rate schedule 1 and pick it up from rate schedule 1 customers. It's a rate change for rate schedule 6 of about 16 percent decrease and it doesn't have, really, any effect. One decimal place past the percentage for rate schedule 1.

So those -- the rate design proposal, as I talked about, they have an impact on the COSA that you can see in the first couple of columns, and then the only rebalancing we are proposing is in the middle on rate schedule 6 and then the COSA after rate design proposals and rebalancing can be seen on the far right-hand corner -- or right-hand side of this table.

The following slide is simply a summary of all the proposed rate changes from the application in a table that is easily reviewed and you can find that in the application in Section 12.4, page 12-8.

From that I'm going to pass it over to Atul.

MR. TOKY: Thanks, Rick. So moving onto slide 106, we'll talk about the FEI approvals sought. It's actually slide number 107 where we do put those approvals sought. The slide actually shows the main headings

1 under which we are seeking some approvals in the
2 application, and these are all based on the rate
3 design proposals that we have discussed in our
4 previous presentation.
5 The detailed approvals sought are included
6 in section 2.2, page 2-3 through 2-5 of the
7 application. One of the things that we haven't really
8 touched upon, I just wanted to mention here is the
9 general terms and conditions which we will be talking
10 about in a bit from now, but those are basically some
11 of the housekeeping and other amendments that we are
12 proposing for our general terms and conditions changes
13 that will go through.
14 Anyways I just wanted to, for the benefit
15 of everyone, just wanted to show what kind of
16 approvals are we seeking. I don't want to go into
17 detail here because there is a lot of material there,
18 and in the end I'm also going to talk a little bit
19 about how we plan to implement these approvals that we
20 are seeking in the application. So basically combined
21 with everything, I think, you know, we are getting a
22 sense of where we are, what kind of approvals we are
23 seeking for and how we want to implement those.
24 Yes?
25 MR. BURSEY: Dave Bursey, Industrial Customers. Just
26 going back to the last slide about the proposed rate

1 changes, do you have the proposed rate changes for the
2 22A and 22Bs?
3 MR. TOKY: The 22As and Bs?
4 MR. BURSEY: Yes. Quite often on these tables that
5 category is always left off, but it would be good to
6 make sure it's included.
7 MR. TOKY: As we discussed in our industrial rate design
8 section, we are not proposing to change or make any
9 changes to the rates, right?
10 MR. BURSEY: But there is one place where it shows a
11 percentage increase in the rates? I could do that off
12 line. I could talk to you and find out where it is in
13 the application.
14 MR. TOKY: Yeah, it will take me some time to just dig
15 up in the application and see where that is, but you
16 know, yeah.
17 **Proceeding Time 2:36 p.m. T52**
18 MR. TOKY: So moving on, I want to touch upon the Fort
19 Nelson rate design and approval sought. So this
20 section is Section 13 of the rate design application.
21 And we did file this as part of our supplemental
22 filing last month. Again, as I said before, I'll use
23 some charts and tables in my presentation. And I've
24 included references in the slides. Those can be found
25 in the application.
26 Slide 109. Unbundling the rates. As part

of the review of the Fort Nelson existing rate design, FEI looked at unbundling the rates. So what do we mean by unbundling the rates? Unbundling refers to separating out the gas cost recovery charges and the delivery charges in the tariff and customer bills.

So this is different, and why I want to say this is different from the concept of unbundling the service that we were talking about in our last workshop, where we discussed that was related to the commodity unbundling, from our Customer Choice program, where marketers sell gas to residential and commercial customers. So this is about unbundling the rates, or the rate structure, if you -- the components in the rates. Which I will touch upon soon.

So why do we need to unbundle the residential and commercial rates? There are a number of reasons why that makes sense. Firstly, it is consistent with the other service areas of FEI. Unbundling of rates for FEI occurred back in 1994. Secondly, because of the transparency reasons. So customers today in their existing rate structure, they can't really see different components. So they can't really see in their bills and their rates different components, and I say gas costs and delivery costs.

From this point of view, if we do unbundle the rates, they will clearly see like other service

areas of FEI, customers can see what are the different components of the rates in their bills are.

Thirdly, it enables ability for the customers to participate in some of the programs that require unbundled rates. So there is the biomethane program, for example. Unless we do this unbundling of the rates, we can't really participate in that program, because we can't really see what are the different components in the rates, or the bills.

And lastly, industrial service rates that we have in place today for Fort Nelson, that's rates 3.1, 3.2, and 3.3, they are already unbundled.

So FEI is proposing to unbundle the Fort Nelson rates. One more thing, and this is the last bullet in this slide I wanted to touch upon, is about the residential customer survey, which we also did for the Fort Nelson customers. Which really shows support for the change to the unbundled rates. So 21 supported bundled rates, whereas about 42 percent of the customers who were surveyed, they supported unbundled, flat rate structure. And for the reasons that Rouz touched upon earlier in his presentation. It's easy to understand, it's simple. It's more transparent.

So in the end, our proposal is to unbundle Fort Nelson rates.

1 COMMISSIONER ENNS: Excuse me.
2 MR. TOKY: Yes?
3 COMMISSIONER ENNS: 21 and 42 is 63. Where is the
4 remaining 37 percent of the survey?
5 MR. TOKY: There are questions somewhere -- and I have to
6 check, going back, check back in the customer research
7 program survey that we had, but they are customers who
8 would be, like, somewhat -- they are indifferent. You
9 know. So there are certain customers like that.
10 COMMISSIONER ENNS: Okay. Okay.
11 MR. TOKY: But we had just picked basically who -- who
12 basically mentioned was clearly on those points, yeah.
13 COMMISSIONER ENNS: No, that's fine, that answers the
14 question.
15 **Proceeding Time 1:36 p.m. T53**
16 MR. TOKY: So slide 110. This is about declining block
17 versus flat rate structure. So one of the things
18 which are different in Fort Nelson as well is that the
19 current rate structure for Fort Nelson's residential
20 and commercial rates is a declining block rate
21 structure. So as you can see on this slide, the
22 table, it shows what rate structure looks like for the
23 residential and commercial customers. They have a
24 minimum charge, they have a first block which is
25 basically the next level of the consumption that they
26 use, and based on that there is a rate, and then there

is a second block. So it's like a tiered block, declining block rate structure.

Despite the advantages of declining block rates in terms of the economic efficiency principle, FEI believes that the flat rate structure is preferable for the following reasons. It's the most common rate structure. So Rouz did talk about, in his presentation earlier on, that we did some jurisdictional comparison and we did look at the other LDCs and what kind of rate structure is being used elsewhere. We found that flat rate structure is the most common of all. A flat rate structure is used by seven out of eleven Canadian natural gas utilities.

Changes in government policy. So government policy has changed significantly during the last twenty years. Today energy efficiency and conservation is a major focus of B.C. provincial government policies. Declining block rates may send price signals that can discourage customer engagement in energy efficiency and conservation programs and activities. So that's another reason why we want customers to go for a flat rate structure rather than a declining block.

As I said earlier, based on our customer survey results, that indicate the flat rate structure is preferred by the majority of Fort Nelson's

1 residential customers. I think, I believe the
2 customer survey is filed as appendix 4-5 in the rate
3 design application, so we can see all the details
4 behind, you know, those statements that I'm making and
5 it's all basically calculated from both the Fort
6 Nelson and FEI customers, when we did the survey.
7 There is lack of evidence of benefits from
8 declining block rates, and why I say that, there is
9 low percentage of residential and commercial customers
10 that actually benefit from declining rates, because
11 majority of Fort Nelson customers, they do not consume
12 more than minimum usage block per month, and therefore
13 are never billed under the second lower rate block.
14 The result is that, for the majority of Fort Nelson
15 customers the current declining block rate structure
16 that we have is effectively the same as flat rate
17 anyways.
18 And the last point is about fluctuating
19 minimum charges. So Fort Nelson's existing rate
20 design consists of minimum daily charge which is
21 calculated based on minimum two GJs per month
22 consumption pro rated on a daily basis. Fort Nelson's
23 existing minimum charge approach results in volutility
24 and fluctuating with natural gas commodity prices.
25 So for all those reasons, we are proposing
26 a flat rate structure for Fort Nelson customers.

So moving to slide 111, this slide shows the existing residential rate design or the rate structure that we have in place and which includes basically all the charges in those different blocks, as you can see. What I also wanted to touch upon on this is that they are about 1961 customers, which is about 80 percent of the total Fort Nelson customer base, with annual consumption of 260 TJs, roughly about 46 percent of the Fort Nelson total demand or consumption.

This is important to know, just to understand what residential customers are, who they are. I'm not touching upon all those other customer characteristics that Rouz had in his presentation, because those are essentially kind of the same in terms of their load factors and load profiles and all those things. On a high level basis, they will be different when we look at them individually on how the COSAs are done, or the cost of service allocation is done. Look at the load factor level.

Proceeding Time 2:45 p.m. T54

Moving on to slide 112, which shows the proposed residential rate design, so when unbundling, there are various ways to apportion the costs for recovery from fixed and volumetric charges. For instance, the daily basic charge can be set to be

equal to FEI's basic charge with the rest of the costs recovered through volumetric delivery charge. Another option would be to set the ratio of fixed basic charge and volumetric delivery charge in a way to achieve zero bill impact for a pre-defined average monthly consumption amount from a customer.

However, both of these options may result in significant bill impacts for certain customers.

So in terms of our proposal for the residential rate design, the first point is that we are unbundling the residential rates. So, meaning, as I explained, separating out the different components in the rates. And then move to a flat rate structure. However, the third point, how do you want to now set the level of the basic charge, is done in such a way that it achieves the lowest dollar amount bill impact for any individual customer in 4,000.

This was done using a linear programming technique in which minimization of the upward increase in the annual bills is set as one of the constraints for our calculations, and that's how we come up with those charges that you see in the table below, that we are proposing.

Now, these charges for rate 1 are prior to any rebalancing, which we will touch upon later on, and see what kind of charges would the final charges

be after any proposed rebalancing.

Moving on, slide 113, the existing commercial rate design. So Fort Nelson commercial customers are served under two rates, really, rate 2.1 and 2.2. Rate 2.1 is referred to as the small commercial; rate 2.2 is the large commercial group.

And as you can see there are about 479 customers. About 80 percent of the Fort Nelson customer base for the small commercial customers and about 22 percent, or just about 7 customers, under rate 2.2.

The current threshold between small and large commercial customers today that exists in Fort Nelson is around 6,000 GJs. So if you remember, when I was talking and discussing the FEI commercial rate design, the threshold between the small commercial and the large commercial customers is 2,000. However, currently, for Fort Nelson, it's about 6,000 GJs.

Just for everyone's reference, in our application and I think we will touch upon this later on as well, we are also kind of changing the naming convention on the Fort Nelson customers. So rate 2.1, for example, it's the small commercial customers, but we are renaming those to rate 2, for example, which was used for the FEI's -- which is consistent with the FEI's naming convention. So if you see in the

application back and forth, you know, those are basically -- that's what we have done. And it's clearly mentioned, I think, in one of the sections in the application too, which we'll touch upon later.

So the proposal on the commercial rate design is again to unbundle the commercial rates, like I discussed ,move to a flat rate structure, but also to set the threshold between small and large commercial customers at 2,000 GJs. In our application we do show that there is no clear separation point for any threshold. However, below 1500 GJs the load factor does vary between 30 percent to 40 percent. Beyond 2,000 GJs, there is a wider dispersion of the load factor that we see. It's around 30 percent to 50 percent.

So again there is no clear, I can say, statistical evidence to support any threshold level in here. And that's why doing some analysis and looking at these are actually the same and similar type of customers that we had back in FEI. We are proposing to set the threshold between small and large commercial customers at 2,000 GJs.

When setting the proposed rates, before rebalancing, the rates for small and large commercial customers at 2,000 GJs would result in the same annual bill. Also attempted to minimize the customer bill

1 impact using the same technique I said, like the
2 linear programming technique that we use in the
3 Microsoft Excel solver.
4 Doing all that, calculations in the
5 background, this is basically, we come up as the
6 proposed charges for rates 2.1 and rate 2.2 before
7 rebalancing.
8 So to summarize, we are unbundling the
9 commercial rates. Moving to a flat rate structure.
10 So coming up with a basic charge, dollar per day, and
11 the delivery charge, dollar per GJ, as mentioned in
12 this table below.
13 **Proceeding Time 2:53 p.m. T55**
14 Slide 115. Industrial rate design. So as
15 I think Rick just mentioned before, there is one
16 customer which is consuming about 40 TJs in the
17 industrial rate -- under the industrial rate. The
18 load factor for about 27 percent, and gas is generally
19 used for space heating to protect equipment and
20 facilities from cold weather. So that customer is
21 basically taking service under rate schedule 25, but
22 we do have the adjustments that we are making under
23 COSA that Rick mentioned in the morning.
24 It's not a typical industrial process load
25 though, because they are using, because of their
26 business constraints, the gas for the space heating

1 and not really for the process load.
2 Anyways, I just wanted to recap that
3 information. What I want to show in this slide is
4 really our proposed industrial rate structure for Fort
5 Nelson, even though there is no such customer under
6 rate schedule 25 which is currently behaving as a rate
7 schedule 25 customer, is to be consistent with the FEI
8 rate structure which you can see in the table below.
9 So there is a comparison here in the slide of the
10 existing industrial rate structure and the proposed
11 industrial rate structure.
12 As mentioned earlier by Kevin, there is a
13 calculation of the daily demand to which the demand
14 charge would apply. So that calculation would still
15 be applied the way we are proposing for the FEI to
16 these customers.
17 Any reference to this can be found in the
18 section 13.5.6 of the application.
19 I know there is a lot of numbers here, but
20 I just wanted to show what are the different
21 components that exist under the existing industrial
22 rate structure and what are we proposing, and if you
23 clearly see -- one of the differences that you will
24 see is, you know, there is a demand charge that we are
25 now proposing to have in the industrial rates.
26 So this slide shows revenue to cost ratios

after we do some rebalancing and I want Rick to basically speak to this, what kind of rebalancing approach we have taken and how we do that in our COSA model.

MR. GOSSELIN: So as with the FEI, what we have to do with the Fort Nelson is we look at our rate design proposals and we look at them and we figure out if they actually have cost allocations in the COSA and if they have revenue allocations in the COSA. For the residential unbundling and unblocking the rate, the proposal for the residential rate, for Fort Nelson there's no change in the cost allocations in the COSA, and there's no revenue difference. We've structure the rates for the residential class, we collect the same revenue.

For the commercial proposal where we propose to shift the threshold, the break-even -- or the economic threshold from 6,000 GJs down to 2,000 GJs, we see both a cost and a revenue shift in the COSA. What happens is folks -- rate 2.1 customers that were in Fort Nelson currently, consuming between 2,000 and 6,000 GJs are now going to be considered -- sorry, yeah, they are going to be considered rate 2.2 customers now.

So we shift them in the COSA from 2.1 to 2.1, create some cost allocation differences, and we

also have a revenue shift that moves from one to the other. Again, the revenue shift doesn't change the proposed rates before any rebalancing because they're paying the same rates today.

So what that does is it shifts some costs and some revenues around in the COSA and we have our results of that COSA, the revenue to cost ratios, the results of that COSA in the first couple of columns there in the table you're looking at.

So rate 1 has a revenue to cost ratio of 82.1; rate 2.1, 117 and so on.

So then we look at, do we need to do any rebalancing at this point? As you can see, all of these customers, these rate schedules -- or rates rather, fall outside the 90 to 110 revenue to cost range that we've been using as a guideline. And so we decide to do some rebalancing.

The first thing we did was we looked at rate 1. They are at 82.1, about 8 percent less than the threshold of 90. So we decide to rebalance them upwards. We rebalance them upwards just enough to kind of maintain the bill shock, the rate shock threshold of 10 percent. So the 9.9 percent is just around -- it's that plus the previous rate design proposal where some customers see about .1. So you sum those two together and the annual bill increase on

1 average for a rate 1 customer, after proposals and
2 after rebalancing, will be ten percent in Fort Nelson.
3 So that's where we came up with the rebalancing amount
4 of 131,000 for rate 1.
5 Next we look at rate 2.1. So where do we
6 give that credit of 131,000 to. What we did was we
7 wanted it to be slip somewhat evenly between rates 2.1
8 and 2.2. Currently they are paying the same rates
9 today. We know they are both outside what they are
10 calling the range of reasonableness, but we felt it
11 was fair to give it across both rate schedules evenly,
12 as evenly as possible.
13 **Proceeding Time 3:00 p.m. T56**
14 So what we did was, we applied 71,000
15 credit to rate 2.1, to bring them down to 110 percent
16 revenue to cost ratio. And that was -- so that hits
17 -- that makes those guys hit the revenue to cost ratio
18 on the upper bound. And then the balance of 60,000
19 we'd do a credit to rate 2.2. It lowers their average
20 annual bill by 14.3 percent, and it brings them down
21 to a revenue to cost ratio of 124 percent, or 123.9
22 percent.
23 So the final revenue to cost ratios after
24 rate design proposals and rebalancing can be seen on
25 the far right side of the table. So that was the
26 approach we took to rebalancing Fort Nelson.

1 THE CHAIRPERSON: Can I ask a question on that?
2 MR. GOSSELIN: Certainly.
3 THE CHAIRPERSON: The 9.9 percent on average.
4 MR. GOSSELIN: Yes.
5 THE CHAIRPERSON: Were there any users that were more
6 impacted than 10 percent?
7 MR. GOSSELIN: I'm certain I've looked at that. I can't
8 recall at this point. It would seem that there should
9 be some that will be higher, that will be impacted
10 more than others, because -- oh, no. Sorry, no.
11 Because what we actually did in this case, we
12 attributed it all to the basic charge. So we put that
13 entire change to the basic charge, all customers
14 receive the same -- basically pay the same basic
15 charge, they all have the same rate impact. That's
16 correct. That's what I did.
17 THE CHAIRPERSON: Thank you.
18 MR. GOSSELIN: Okay.
19 And this last slide is a summary of the
20 rate proposals for Fort Nelson. And I think it can be
21 found in Section 13.7.2. I think the point we want to
22 look at, there's lots of rates and everything, you
23 know, lots of stuff going on in this slide. What we
24 really want to focus on is the total annual bill
25 before and after. So we have total annual bill just
26 above the pink line. This is slide 117, for those on

the phone. For rate 1, we see $742 and the total annual bill after proposed rates -- after proposed changes and rebalancing of $816 for rate schedule 1. So I think to do the math on that, and you'll see it's 10 percent rate increase. And so on for the balance of the rates in Fort Nelson.

COMMISSIONER EVERETT: Sorry.

MR. GOSSELIN: Yes?

COMMISSIONER EVERETT: Did you say that when you get to 10 percent, that's rate shock?

MR. GOSSELIN: Yeah, that's what we've used as a guideline for rate shock when making any of these changes, proposals, and rebalancing.

COMMISSIONER EVERETT: Yeah. So your point 1 under rate shock, is that right?

MR. GOSSELIN: No, the point -- if I can remember -- there's two changes. There's a small change to -- how did it go?

There is an additional change in the Fort Nelson that adds 0.1 to the residential rate. So when you take that plus the 9.9 you get to 10. I'd have to take a look at my notes to explain to you exactly what that was again.

But at 9.9, we're 0.1 below rate shock, yes.

COMMISSIONER EVERETT: Yeah. So to balance, you're

1 essentially pushing everything to residential.
2 MR. GOSSELIN: In this case, we brought residential up.
3 COMMISSIONER EVERETT: Yeah.
4 MR. GOSSELIN: And pushed the credit to the rate
5 schedule, commercial and -- the two commercial rate
6 schedules, yes.
7 COMMISSIONER EVERETT: And is there another way of doing
8 it?
9 MR. GOSSELIN: I suppose you can propose many different
10 ways to rebalance. I mean, it's really just a numbers
11 game, trying to get people closer to the range, what
12 we call the range of reasonableness.
13 COMMISSIONER EVERETT: Mm-hmm.
14 MR. GOSSELIN: The rebalancing amounts, if you felt that
15 10 percent was just too much, you can mitigate that
16 and do only half of it, or perhaps propose a phased-in
17 approach over a couple of years.
18 There is -- from a pure cost causation, or
19 a cost allocation perspective, compared to the
20 revenues, it's just a math exercise to figure out
21 where you are. It doesn't mean that -- it doesn't
22 mean you have to go to the extent that we did, but
23 this is what we're proposing in our application.
24 MR. TOKY: I just want to add a little bit on that. So
25 there is different competing principles when we look
26 at doing the rebalancing as well. When you look at

the real cost causation point of view, we do have this range of reasonableness that Rich is mentioning.

Proceeding Time 3:05 p.m. T57

So if you look at 9210 percent of fees, whether it's reasonable, those revenues that we are collecting from those customers based on their allocated cost of service, and if you see in that table, residential class is the one which is not -- which is below 90 percent, let's say, like in terms of their revenue to cost ratio, and that's the reason we did this way in terms of the rebalancing what we did, but then when you do that, you have to look at the other competing principles is that you should not be providing any rate shock to the customers. So you look at the other competing principle and seeing that, okay, is the rate going to be stable for them, and look at all those things in totality and come up with something.

So yeah, there are a lot of ways we can do this, but we proposes this in the application, for reasons as mentioned by Rick.

MR. GOSSELIN: Are there any further questions?

MR. TOKY: So we are on slide 118, which talks about the postage stamp rates for Fort Nelson So FEI is not proposing to postage stamp Fort Nelson rates at this time. FEI did the rate impact analysis to Fort Nelson

1 customers. Their delivery rates and gas cost recovery
2 charges were to be postage stamped with the rest of
3 the FEI service area.
4 So the table that you see in the slide
5 above, it's basically a summation of the effective
6 delivery variance and the cost of gas variance that we
7 looked at in our analysis. In addition to the rate
8 differences summarized above, and in consideration of
9 the proposed rebalancing that Rick just mentioned and
10 delivery rate changes which are already approved for
11 2017 and 2018, based on Fort Nelson's revenue
12 requirement and rates application, we see that there
13 is still a lot of variance in the rates, and that's
14 why we are not proposing to postage stamp rates for
15 Fort Nelson customers at this time.
16 If you see the major reason for the
17 variance in the Fort Nelson rates in the table,
18 compared to FEI rates, is due to the midstream cost
19 recovery which is approximately 2 to 3 cents per GJ as
20 compared to about a dollar per GJ for FEI. Delivery
21 rate differences for commercial customers are modest,
22 but residential customers would see a dollar and --
23 like a 9 cents per GJ increase. So those are the
24 reasons why we are not proposing to postage stamp Fort
25 Nelson rates.
26 Slide 119, approval sought for Fort Nelson.

Again, these are all the major categories under which we are seeking approvals for Fort Nelson. The detail approvals sought are included in section, I believe, 13.1, page 13-1 through page 13-5 of the rate design application, and it does incorporate all those proposals that we just mentioned in our previous slides here.

So like I said, on the renaming of the rate schedule, so we are basically changing the naming convention for the Fort Nelson, so that's what you will see there. The unbundling of the rates that we talked about, so there is approvals that we are seeking, those are mentioned over there. That involved some changes to the billing system costs. That's also included in the approvals sought section of the Fort Nelson.

Proceeding Time 3:10 p.m. T58

Up next we have FEI general terms and conditions and the rate schedules that we want to talk about, and some of the proposed amendments, and we'd like to have Colleen Gravel, she's our tariff rate designs and project manager, to come in and present that.

MS. GRAVEL: Good afternoon. My name is Colleen Gravel, and I am the tariff rate design and projects manager at FEI. Today I'm going to provide a brief overview

1 of the proposed amendments to the FEI general terms
2 and conditions, known as the GTs and Cs, the FEI rate
3 schedules, and the Fort Nelson gas tariff.
4 Beginning with the FEI GTs and Cs, FEI has
5 proposed general wording and housekeeping changes to
6 most sections of the tariff. Within the GTs and Cs,
7 there is the standard charges schedule, currently
8 referred to as the standard fees and charges schedule.
9 FEI has proposed a decrease to the application charge
10 currently referred to as the application fee, from $25
11 to $15. This proposed decrease reflects increased
12 efficiencies in the business processes resulting from
13 access to online and electronic information required
14 to perform this service. In addition, we have
15 proposed a decrease to the return payment charge,
16 previously known as the dishonoured cheque charge,
17 from $20 to $8, which reflects a decrease in customer
18 service representative work due to improved automation
19 and banking process.
20 Appendix 11-12 in the application outlines
21 the calculations for the proposed changes to the
22 application and return payment charge.
23 The black-line version of the proposed
24 amendments to the GTs and Cs, including the standard
25 charges schedule, can be found in Appendix 11-1 of the
26 application.

1 Next is a summary of the proposed
2 amendments to the FEI rate schedules. For rate
3 schedules 1 to 27, FEI has proposed general wording
4 and housekeeping changes. For rate schedules 22 to
5 27, the FEI transportation service rate schedules, the
6 table of charges for each rate schedule has been
7 updated to reflect daily balancing, including the
8 proposed daily balancing threshold of 10 percent and
9 the corresponding charge of 25 cents a GJ.
10 In addition, for rate schedules 23 to 27,
11 which are currently monthly balanced, the terms and
12 conditions have been updated to reflect the proposal
13 of daily balancing. FEI has also proposed a decrease
14 to the administration charge per month from $78 to
15 $39. This proposed decrease reflects a decrease in
16 transportation service administration costs. Appendix
17 11-4 of the application outlines the calculations of
18 the cost review for the proposed decrease to the
19 administration charge.
20 Finally, we have proposed to cancel rate
21 schedule 6A, general service vehicle refueling
22 service, and rate schedule 40, west to east Southern
23 Crossing Pipeline transportation service, as there
24 have not been any -- as there has not been any
25 customer uptake for service under these rate schedules
26 for many years.

The black-line version of the proposed changes to the FEI rate schedule can be found in Appendix 11-3 of the application.

Finally, I would like to discuss the proposed amendments to the Fort Nelson gas tariff. FEI has proposed amendments to the terms and conditions of each new proposed rate schedule which mirror FEI where possible. Beginning with the proposed rate schedule 1, residential service, currently referred to as rate 1 domestic service, the proposed terms and conditions are consistent with FEI rate schedule 1 and the proposed table of charges outlined the different rate components, i.e., the basic charge per day, the delivery charge per gigajoule, et cetera. These similar amendments have been proposed for the new proposed rate schedules 2, 3 and 5.

Proceeding Time 3:15 p.m. T59

With respect to rate schedule 25, We have proposed amended terms and conditions which generally reflect FEI's current rate schedule 25, including daily balancing and the reduction of the administration charge per month from $202 to $39. The black line version of the proposed changes to the Fort Nelson gas tariff can be found in appendix 13.6 of the application.

And that's all I have. Thank you. Are there any questions?

MR. TOKY: So that brings us to really the last part of the workshop today, which is really to talk about the next steps and I do have a couple of slides on this which I'd like to go over with all of you.

Like I mentioned before, I wanted to touch upon the implementation of the approved changes. FEI is targetting June 1st, 2018 as the implementation date for these redesign changes as being proposed in the application, and why that date, the middle of the year is, is because it provides sufficient time for the review of the rate design application. It does provide sufficient time for FEI to implement changes, and this is less complex if, you know, if we combine this with other changes, like the delivery of the gas cost changes. It will be easier for our customers to understand and more clear for them to understand what kind of changes are we proposing which are coming straight out of the rate design application and not really impacted by the other applications or the approvals like, you know, the revenue requirements or the gas cost changes that we normally have during the beginning of the year and every quarter.

So with that being said, this is the target and we'll see how the process goes and based on that

we'll probably look for a compliance filing at a later date or something, to make sure that everything fits in within the time frame that we have to implement those changes.

I just wanted to put this slide on. This is the regulatory timetable. So, yeah, I'm not going to go through each and every line item here, but I do want to mention that there is a process in front of us which we can see on this slide, and there is a further process which is to be determined after we have the procedural conference which is scheduled for Wednesday July 5th, and before that we have all those things -- or the action items in the process being placed by the Commission

Proceeding Time 3:18 p.m. T60

So with that, this really concludes our presentation for the workshop today. We are happy to take any further questions on this or any other comments that you would like to make.

THE CHAIRPERSON: The Panel would like to thank FEI and all the presenters. The presentation was very helpful to the Panel and to all the participants in understanding the COSAs and understanding the rate design proposals included in the application.

I'd like to thank all the other participants and look forward to the rest of the

1 regulatory timetable.
2 Thank you.
3 MR. TOKY: Thank you. Thanks.
4 **(PROCEEDINGS ADJOURNED AT 3:20 P.M.)**
5
6 I HEREBY CERTIFY THAT THE FORGOING
7 is a true and accurate transcript of
the recording provided to me, to the
best of my skill and ability.
8
9
10 A.B. Lanigan, Transcriber
11
12 March 9th, 2017
13
14
15
16
17
18
19
20
21
22
23
24
25
26