October 6, 2015
(9:05 a.m.)
CHAIRMAN:
Q. Once more into the trenches. I think we got one undertaking, is that correct, madam?
MS. PENNELL:
Q. We do, Mr. Chair. We have Undertaking 11.
CHAIRMAN:
Q. Okay, so you -
MS. PENNELL:
Q. Already done.
CHAIRMAN:
Q. So we're back to you, I think, Mr. Johnson, to start your cross-examination of Mr. Fagan.
JOHNSON, Q.C.:
Q. Yes, thank you very much, Mr. Chairman.
MR. KEVIN FAGAN - CROSS-EXAMINATION BY THOMAS JOHNSON, Q.C.:
JOHNSON, Q.C.:
Q. Good morning, Mr. Fagan.
MR. FAGAN:
A. Hello, Mr. Johnson.
JOHNSON, Q.C.:
Q. In relation to the August 14 settlement agreement, one of the things Hydro has agreed

is that Hydro will be filing a general rate application no later than March 31st, 2017, for rate changes based on a 2018 test year, right?
MR. FAGAN:
A. That's correct.
JOHNSON, Q.C.:
Q. And so given this, Mr. Fagan, the rates that we are going to be determining in this present GRA, these rates will be in place for 2016 and 2017 period, right?
MR. FAGAN:
A. Yes.
JOHNSON, Q.C.:
Q. Okay, now Mr. Fagan, both Mr. Patrick Bowman and Mr. Greneman agreed during their testimony, as they both testified, that one of the underlying principles behind cost of service analysis is that it's never a precise tool for cost allocation, however, the analysis should reflect fair and reasonable estimation of the cost responsibility between customer classes for the periods in which the study is being applied. Do you recall those gentlemen agreeing to that statement?

MR. FAGAN:
A. Yeah, I take no issue with that, yeah.
JOHNSON, Q.C.:
Q. Mr. Fagan, likewise, I take it that you would be in complete agreement with that statement of principle as well?
MR. FAGAN:
A. Yes, I think sometimes in our jurisdiction it take a combination of both base rates and regulatory mechanisms to achieve that, but, yeah.
JOHNSON, Q.C.:
Q. Okay, so Mr. Fagan, I guess we would be in total agreement that rates are to be just and reasonable at all times, right?
MR. FAGAN:
A. To the extent possible, yes.
JOHNSON, Q.C.:
Q. Now Mr. Fagan, the other thing that's an element of the August 2015 settlement agreement is that the parties have agreed that the year to date net load variation for Newfoundland Power and the industrial customers shall be allocated among the customer groups based on energy ratios with

effect from the date to be determined by the Board, right?
MR. FAGAN:
A. That's right.
JOHNSON, Q.C.:
Q. So the date from which it comes into effect is left to be determined by the Board?
MR. FAGAN:
A. And Hydro has proposed that to be September 1st, 2013, I believe.
JOHNSON, Q.C.:
Q. Exactly. Before we get there, is the RSP designed whereby load variations shall be allocated on the basis of energy ratios? That would be consistent with what Hydro proposed at the 2006 GRA, isn't it?
MR. FAGAN:
A. That's correct.
JOHNSON, Q.C.:
Q. That's right, and coming out of 2006 GRA, that's where the parties, I think you'll agree, agreed to examine a redesign of the RSP to better meet design objectives, is that right, do you recall that?
MR. FAGAN:

A. Yes, that's correct.
JOHNSON, Q.C.:
Q. Okay, and so Mr. Fagan, I take it you'd agree that by the parties agreeing to undertake this study, the parties are acknowledging that the RSP rate design had inadequacies?
MR. FAGAN:
A. I think they agreed that it should be reviewed. I don't think there was an agreement necessarily on whether there was inadequacies by all parties. Some parties thought there was inadequacies, so everybody agreed to do a review.
JOHNSON, Q.C.:
Q. Okay, and that review or that study of the RSP rate design, as we know that was not completed, right?
MR. FAGAN:
A. That's correct.
JOHNSON, Q.C.:
Q. Mr. Fagan, does the allocation of the load variation component of the RSP on the basis of energy ratios, does that result in your judgment rates that better reflect costs and leading to rates that are more just and

reasonable?
MR. FAGAN:
A. It simulate rerunning of cost of service study for energy, effectively, between test years. So it attempts to almost update customer rates to reflect - almost like recreation of a test year from an energy cost perspective between test years, so I think that probably better reflects the cost of serving the customer classes.
JOHNSON, Q.C.:
Q. Okay, and rates that better reflect costs, they would be seen as being more just and reasonable?
MR. FAGAN:
A. Yes, I think so.
JOHNSON, Q.C.:
Q. Now Mr. Fagan, can you confirm - my understanding is that when the original 2013 GRA was filed, the industrial customers were paying approximately 65 percent of the cost of power determined in the 2013 cost of service study?
MR. FAGAN:
A. Could you just repeat the question? I just

got distracted for a moment.
JOHNSON, Q.C.:
Q. No problem. Can you confirm that when the original 2013 Hydro GRA was filed, that the island industrial customers were paying about 65 percent of the cost of power as determined in the 2013 cost of service study?
MR. FAGAN:
A. Subject to check, but it sounds reasonable.
JOHNSON, Q.C.:
Q. Yes.
MR. FAGAN:
A. Given the large percentage increase that was proposed.
JOHNSON, Q.C.:
Q. And just to - the reference that I would have on that, and I believe it's on the record as part of this GRA proceeding, is RSP-CA-NLH-12. I don't know if Jennifer can bring that up.
MS. GRAY:
Q. Sorry, just one moment.
MR. FAGAN:
A. It's a fairly long record to find everything.
JOHNSON, Q.C.:
Q. Yes.

MS. GRAY:
Q. I'm sorry, Jacquie, do you know where I can find -
MS. GLYNN:
Q. We're trying to find it as well.
MR. COXWORTHY:
Q. I think it's with the other CA-RFI. It's a separate group for the RSP.
MS. GRAY:
Q. Yes, thank you.
JOHNSON, Q.C.:
Q. I'm referring Mr. Fagan to Attachment 1 to that answer. You see the second - over to the right of the page, just back one column. It's headed up, "The ratio current average rate to test year and average cost of service rate", and as you see at the bottom, the total island industrial was 65.26 percent. So that just confirms that number.
MR. FAGAN:
A. Yes.
JOHNSON, Q.C.:
Q. And at the time, if we go up and look at Newfoundland Power, for instance, they're nearly up to the full cost of - they're at

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98.24 percent. Mr. Fagan, there's been some discussion of 37.6 million dollar figure that got transferred to the benefit of the industrial customers, and, I guess, we've termed it as a subsidy by small customers to the industrial customers. The small customers were paying for the rates and all the RSP adjustments through the time period, but, I guess, the question would be, the industrial customers rates, the reason that they were so far under the cost of supply was because their rates had been made interim or frozen, if you will, right?

MR. FAGAN:

A. That's correct.

(9:15 a.m.)

JOHNSON, Q.C.:

Q. Now the 37.5 million dollar amount or subsidy became crystallized, I take it you would agree, by the Board's Order in PU-26-2013, an order that I would hasten to add the Board had no choice but to issue in light of the directive, right?

MR. FAGAN:

A. I don't know if I can accept the term

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"subsidy". The term "subsidy" is presupposing, I think - if the government had not issued direction on disposition of the RSP surplus, it would have went back for review by the Board. So I'm unsure if the Board would have necessarily used the energy ratios purely in determining the allocation of the RSP surplus between retail customers and industrial customers without considering potential impacts on industrial customers. So the Board may have come to some compromised solution as well, so I don't know if I can accept the assumption that energy ratios would have automatically fallen out had it come back to the Board for review.

JOHNSON, Q.C.:

Q. But one thing is certainly the case that Hydro believed that it should go by way of energy ratios. That was the fair and just approach, right?

MR. FAGAN:

A. Oh, yes, certainly.

JOHNSON, Q.C.:

Q. Yes, and so in terms of the hesitation then to calling it a subsidy, Mr. Fagan, I mean, you

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would be familiar with the fact that the 37.6 million dollar amount, that would be in excess of the average annual amount paid by industrial customers for power from '08 to 2012, right?

MR. FAGAN:

A. It's my understanding that the amount you're referring to, the amount in excess of what they would have - industrial customers would have received on just an energy ratio basis. That would be the basis for the 37 million.

JOHNSON, Q.C.:

Q. Right, right, indeed. So if the had - if the Board had acceded, say, to Hydro's and Newfoundland Power's, and Consumer Advocate's position that it should go by way of energy ratios, what amount would they have gotten as opposed to 37.6?

MR. FAGAN:

A. Well, had the change been made back then, then obviously the industrial customers wouldn't have received that money through government directive. It's really difficult to take it and look at it in isolation without looking at what's been done has been done with regard to

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the uncertainty of industrial rates over time due to the closure of the paper mills, and the funds were held in the industrial customer balance until it was determined how they would be disposed of. So to go back now and say that, well, they obviously didn't pay their way, they may be of the opinion that they've taken the risk somewhat with regard to the way the RSP was set up, that if their energy usage went up versus down, then they would bear the cost of it. That's the way the RSP rules were at the time. So to me, I don't think you can look at one piece in isolation without looking at the fact that it was in the industrial customers account. Now we've got to go back and - ignoring the government directive, we've got to go back and try and address this matter, and so if the Board was going back to try and address this matter, they'd obviously look at the energy ratios, but I think they'd also have to look at how do we recover those costs that have not been recovered from industrial customers since 2007. I think gradualism is a term that's generally used in rate design, so I don't think this is strictly

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cost allocation because you've also got to look at recovery of costs. They may have had some other views on would they have somehow used some of those funds to gradually phase in industrial customer rates back to costs, I don't know, but I don't think I can assume that they would have viewed it as an isolated matter of strictly recovering the cost.

JOHNSON, Q.C.:

Q. Okay, but in terms of what Hydro's position would have been, if Hydro's position would have been acceded to in terms of basing it on energy ratios, I take it that mathematically the industrial customers would have gotten only a small fraction of the amount that the ended up getting credit for, right?

MR. FAGAN:

A. Hydro put its position forward on energy ratios in 2006 before all the matters occurred with regard to the closure of the paper mills and the accumulation of the balances in the RSP. If Hydro had to come forward with a proposal to the Board to deal with the disposition of the RSP surplus rather than being a directive from the government, I'm not

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sure if Hydro would have proposed strictly energy ratio and a full recovery of all the costs from industrial customers.

JOHNSON, Q.C.:

Q. But in the proceeding four years after 2006 in 2010, Hydro's - and that's the one that led to the jurisdictional issue, etc, but Hydro's evidence indicated that it should go by energy ratios at that time too, right?

MR. FAGAN:

A. I don't think Hydro deviated from the position that it should have been shared on energy ratios.

JOHNSON, Q.C.:

Q. That's right.

MR. FAGAN:

A. My only point is that with regard to implementation of industrial rates, you've got to look at the impact on customers as well, that's all, but Hydro's position was clear, it should be proposed on energy ratios since 2007.

JOHNSON, Q.C.:

Q. That's right. I guess, there's no question that, in effect, the effect of OC-089, OC-

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2013-089, the effect of that is that the island industrial class received the equivalent of about 1.5 years of power based upon the annual amount that they had been paying over '08 to 2012, correct?

MR. FAGAN:

A. The 37 million you're referring to equates to that.

JOHNSON, Q.C.:

Q. Yes.

MR. FAGAN:

A. Yes, that's correct.

JOHNSON, Q.C.:

Q. Yeah, that's right. Now given the fact that the Order in Council did something quite different than an energy ratio approach, did Hydro consider this big transfer that occurred by virtue of the Order in Council when it decided to propose in this amended GRA that effective September 1, 2013, that the year to date net load ratio would be allocated based upon energy ratios?

MR. FAGAN:

A. Well, Hydro's view is that government made a policy decision on disposition of the

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historical balance, and so Hydro has maintained its approach and principle of how it should be done going forward, and how we believe it should be done going forward, and going forward, I mean from the point of August 31st, 2013, when government made its decision, we propose it be done on energy ratios going forward, and we felt it's a principle basis, it's consistent with cost of service, so Hydro proposed it in that manner.

JOHNSON, Q.C.:

Q. Okay, but you would agree that Order in Council 2013-089 in no manner provides direction to the Board with respect to the amounts built up in the load variation account since September 1st, 2013, right?

MR. FAGAN:

A. Oh, I agree. However, I don't know if - even if Hydro disagreed with the government's disposition approach to the balance, I don't think you should deviate from your principles and say, okay, I'll try to claw that back in the future. I think you'd still want to look forward and say what's a fair way of doing it.

JOHNSON, Q.C.:

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Q. Would there be a case, Mr. Fagan, for the Board transferring the balance in the load variation that has accumulated from September 1st to Newfoundland Power's RSP account on the basis of the fact that the 37.6 million dollar credit that went to the ICs was so materially different than what would have been the result on energy ratios approach?

MR. FAGAN:

A. I mean, from a consumer perspective, if one believed there was a subsidy, one would say, well, that wasn't fair, I should get that back, but from a community rate making approach, we're looking at government policy directs Hydro in certain matters, so government policy dealt with that historical matter. Now looking forward, we've got these costs, fuel cost variances due to load growth, so from a cost of service perspective, it should be shared based on the energy proportions between Newfoundland Power and industrial customers, so that's what Hydro is proposing.

JOHNSON, Q.C.:

Q. So if the Board concludes that it was, in

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fact, a subsidy that occurred there, you would think that the Board should be open to the idea of saying, look, monies that have built up from September 1st, 2013, could, in fact, legitimately go to Newfoundland Power customers?

MR. FAGAN:

A. I mean, the Board would have authority to determine the disposition of the load variation balance that's accumulated since September, but, I mean, the Board generally follows generally accepted practices, and these are fuel costs, and fuel costs are generally allocated based on energy usage. So from the perspective of fairness of sharing costs looking forward rather than looking backwards, I think they would lean towards the energy basis, but I wouldn't - I can't say what the Board would do with respect.

JOHNSON, Q.C.:

Q. Mr. Fagan, in light of what the Order in Council mandated happen, in your judgment did this result in rates covering the period of 2008 through to August 31st, 2013, that were just and reasonable?

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MR. FAGAN:

A. It's very unusual circumstances that occurred with respect to rates over the period 2007 to 2013. It's hard to view that being the fault of industrial customers with respect to - there was a closer of paper mills, there was fuel savings. The RSP rules required those fuel savings to go into the industrial customer account. Then there was a debate over where these fuel savings should go. It took a fair bit of time to get it resolved, obviously, and a court case as well. What the government directive did effectively was almost effectively established the policy that we're settling this dispute and putting enough funds there to say the industrial customers would have - it would have recovered all the additional fuel costs between 2007 up to August 31st, 2013. I can understand one coming to that conclusion. It's difficult in the circumstances looking back whether you should judge whether rates reasonable reflected costs. I don't know looking back whether one would disagree necessarily with what the government did from, you know, the

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perspective of their judgment because they could view it that, well, it wasn't industrial customers fault with regard to what happened here, and so why should now we go back and impose - be accumulative towards industrial customers because of the unfortunate circumstances of the closure of the paper mills and the impact it had on customer rates. So it's a little bit of an unusual circumstance with regard to assessing whether the rates were just and reasonable. I think at this point we look and say the rates are not recovering current costs, so based on government direction dealing with historical now we'll try and make rates just and reasonable going forward. Looking back on it, it's kind of difficult to assess. Obviously, the industrial customers weren't paying rates that recovered their base rate cost plus the fuel cost as the fuel price went up over the period 2007 to 2013, but the industrial customers would probably argue that there was balances in the RSP accumulating that they felt entitled to which were appropriate to apply against that amount. So I think it

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depends which side of the fence you're on.

JOHNSON, Q.C.:

Q. But as you're aware, I mean, it's been determined by the highest court in the province that there was no entitlement, there was no vested right in the industrial customers in any of these monies.

MR. FAGAN:

A. Oh, no, I

JOHNSON, Q.C.:

Q. So they can say, well, we felt we were entitled to it, right?

MR. FAGAN:

A. I agree.

JOHNSON, Q.C.:

Q. I mean, that's the landscape, and during this period when industrial customers were paying 65 percent - some of them actually lower, you know, Teck 56 percent, Vale 56.78 percent, during this period Newfoundland Power customers were paying the full freight, right?

MR. FAGAN:

A. Yes, Newfoundland Power customers were recovering the costs because their rates were adjusted each July for fuel price increases.

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JOHNSON, Q.C.:

Q. Right, exactly. So again I come back to, you know -

MR. FAGAN:

A. Well, in hindsight, it's hard to argue that the industrial customer rates were below cost in that period. So if you deem that to be not reasonable, I mean, we probably could agree it's not reasonable, but the circumstances were a little unusual which resulted in that. So it's hard to fix the past somewhat with respect to that.

(9:30 a.m.)

JOHNSON, Q.C.:

Q. Well, in terms of - we're not talking about fixing the past, we're talking about a comment upon the past, and what I'm asking is Hydro's comment as to whether or not it believes that the rates covering the period 2008 through August, 2013, having regard to the Order in Council, produced just and reasonable rates?

MR. FAGAN:

A. I think it would be difficult to accept that the rates that the industrial customers paid over the period 2007 to 2013 were reasonable

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given the cost to provide service. One could certainly - they were outside the range of where one would want to take action to try and increase it, so from that perspective, I think I'd say that the rates were too low.

JOHNSON, Q.C.:

Q. And the monies that did happen to build up in the load variation account by reason of IC load dropping off, I mean, it's obvious, but I'll just state the question, that had nothing to do with the industrial customers responding to a rate signal in their rate and conserving or finding efficiencies of operations, right?

MR. FAGAN:

A. That's correct.

JOHNSON, Q.C.:

Q. It's just a shutdown that Hydro was left in the lurch on, as I understand it, I read about it in the paper.

MR. FAGAN:

A. It was a result of the closure of the mills and a fuel savings that resulted from it, yes.

JOHNSON, Q.C.:

Q. Of which Hydro was given no advance notice?

MR. FAGAN:

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A. I really couldn't say on that, but I think there's been evidence on the record to that effect.

JOHNSON, Q.C.:

Q. Yeah. Now with respect to the industrial customer rate phase-in in this matter, Hydro's amended application requests that the phase-in of island industrial customer rates be completed by September 1st, 2016, as set out in the evidence in support of the application. That's what the formal application before the Board states at Paragraph 44, Sub 28.

MR. FAGAN:

A. That's correct.

JOHNSON, Q.C.:

Q. Mr. Fagan, what increase is needed and when to bring the island industrial customer rates up to the full cost of supply as required by 2013-089?

MR. FAGAN:

A. Jenny, could you bring up response to PUB-NLH-485. We'll look at Table 1 first. So this table represents the proposed rates based on the fuel cost of $93.32. So the industrial rate increase there will be 27 percent.

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Relative to the existing rates, okay, I think - if we go to footnote 3, there's an RSP surplus effect that's excluded here, okay. So it's 27 percent there. Now if we go to Table 2, in Table 2 we're showing a change relative to the rates in place January 1, 2015, of 13.2 percent. Now this is reflecting of fuel price of $73.00 a barrel. That's probably close to what the forecasted fuel price is for 2016. We'll be filing next week, I think, it's around $70.00 a barrel. I mentioned yesterday, and I expect Mr. Coxworthy will request an undertaking if Mr. Johnson doesn't, with respect to the calculations supporting rates for January 1, 2016, and September 1, 2016, but we've done some preliminary work on the numbers which would indicate if the Board approved the proposed rates that we've filed, adjusted for the test year fuel price in this case would have been the $73.00 a barrel, you'd have an increase to industrial customers that would bring them up to the full base rate January 1st. I don't know if it's before Table 2, mentioned RSP surplus adjustment that we would propose to be updated, so Hydro's

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proposal is that we'd have full base rates in play by January 1st, 2016, but with the RSP surplus adjustment updated to permit the remaining disposition of the approximately 11 million dollars that was left there for phasing in industrial customer rates. I think, based on what the Board approved in July, I think there's about a 3 million dollar balance forecast at the end of 2015, which will continue to be used for phasing in industrial customer rates. If the Board approved the revised industrial customer rates, January 1st, to be an increase looks like between 7 and 8 percent to get them to full base rates, and then the RSP subsidy would be phased out, RSP surplus, not subsidy, RSP surplus adjustment will be phased out September 1, 2016, and so they'd have no RSP surplus adjustment and be at full base rates, and I think the increase there would be in the neighbourhood of around 13 percent. So still facing approximately a 20 percent increase between January to September to move them to full cost rates.

JOHNSON, Q.C.:

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Q. Mr. Fagan, since you've hinted at an undertaking in that regard, I think I'll take you up on it.

MR. FAGAN:

A. We've got the numbers worked out for the industrial customers, excluding Teck. Teck is a little bit more complicated because of the closure and the - load demand, so just fine tuning the numbers for Teck, but we'll provide something, okay.

JOHNSON, Q.C.:

Q. Okay, thank you.

MS. GLYNN:

Q. The undertaking is noted on the record.

MR. FAGAN:

A. Okay.

JOHNSON, Q.C.:

Q. Obviously, there's a bit of complexity to this and, I guess, I'm going to ascribe to the view there's no such thing as a foolish question, but maybe there is, but it's one that I want to have answered in my head, and that is in order to complete the phase-in of IC rates by September 1st, 2016, will that require a specific order from the Board arising out of

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this GRA, or would you be contemplating further orders of the Board subsequent to the Board's GRA order to accomplish that?

MR. FAGAN:

A. Well, let's go to the January 1st concept I just put forward, okay.

JOHNSON, Q.C.:

Q. Yeah.

MR. FAGAN:

A. Normally there would be a fuel rider update for industrial customers, January 1st, okay. Hydro will be putting a fuel forecast on the record next week which would normally be used to establish a fuel rider. The current RSP rules have set the fuel rider to zero, subject to a further order of the Board, okay. So there will be required to be an order. I don't anticipate a final Board order on customer rates prior to January 1st. It would be nice, but it would be a bit of a stretch, I would think. Hydro has filed - when Hydro filed its amended application, it requested interim rates and the proposed rates that were put before the Board to become interim January 1st, 2015. The Board approved interim rates in July. I'm not sure if an additional application is required for the Board to approve the proposed rates for industrial customers proposed base rates to become interim January 1, 2016, and the RSP adjustment to be updated, but probably may want to talk to Board staff about that to determine how we proceed with that.

JOHNSON, Q.C.:
Q. Okay.

MR. FAGAN:
A. That would be the desirable approach with regard to implementing industrial rates, January 1st, and permitting the remainder of the transition to full cost rates, including the RSP surplus credits, to come into play for September and - January and September.

JOHNSON, Q.C.:
Q. Has Hydro had discussions with the ICs about what it sees coming in terms of the rate progression under the phase-in?

MR. FAGAN:
A. Other than what I presented yesterday, we haven't had discussions on it, no. Now the information that I presented yesterday was

provided in response to CA-NLH-363, so it's been out there.

JOHNSON, Q.C.:
Q. Yes.

MR. FAGAN:
A. It's just the actual impact of that proposal haven't been clear.

JOHNSON, Q.C.:
Q. And CA-NLH-363 basically summarized the plan of Hydro to get to full phase-in by September 1st, 2016?

MR. FAGAN:
A. Yes.

JOHNSON, Q.C.:
Q. Okay.

MR. FAGAN:
A. Because there's - we got CA-NLH-363 presented here now, so in September, 2003, there was a large rate increase, right, and Hydro filed a number of applications since that time to try and increase industrial rates in an interim basis, but we were only successful in July of 2015 to achieve increase in industrial rates. So fortunately the fuel prices declined, so that the impact on industrial customers is not

as large as it would have been had it stayed up to $93.00, but it's still a material increase.

JOHNSON, Q.C.:
Q. Okay, turning to the rural deficit issue, and some of this ground is well trodden, and I understand sort of help in trying to focus a little bit, but just to confirm, Mr. Fagan, Hydro does believe that the rural deficit allocation issue should be dealt with at this hearing?

MR. FAGAN:
A. Yes.

JOHNSON, Q.C.:
Q. Okay, and, in fact, you offered yesterday that based upon your experience with the 1992 hearing, you reckoned that there's been, in fact, more discussion of the rural deficit allocation at this hearing than what took place back in '92?

MR. FAGAN:
A. Well, at the 1992 hearing, Mr. Brockman was an expert, Mr. Sarikas was an expert for Hydro, and Mr. Baker was an expert. So we've had more experts deal with it here, and all the

experts that presented prefiled evidence, plus Dr. Wilson has also commented on it, that all except Mr. Brockman support Hydro's proposal, and there's been a lot of analysis and information provided to the Board, a lot more material I would suggest than was presented in 1992.

(9:45 a.m.)

JOHNSON, Q.C.:
Q. Mr. Fagan, when Mr. Brockman was testifying - if we could bring up the transcript from September 29th, Jennifer, Page 214. This is in discussion - he's being questioned by Mr. Luk, and Mr. Brockman is talking about this phase-in idea, and he says part way down his reply, "You don't necessarily have to phase it all in, maybe just say I'm going to do a little bit or maybe you don't do any if you think there's going to be a rate case. I guess, Hydro said they're going to file again, subject to check, next year, maybe 2017", and then he says, "But I wouldn't phase it all in by then, and I probably would never phase it all in because then everything is going to change again, so maybe I'd just give you 3

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percent and we'll see what happens, you know, once we review all the stuff. I don't change the methodology, I don't give you all of this either because there does seem to be a lot of controversy about it". Mr. Fagan, in your opinion, is this a realistic solution to the rural deficit allocation problem or is this just kicking the problem down the road?

MR. FAGAN:

A. Well, I struggle with phasing in a rate change based on what most people would agree that the cost is not an appropriate cost for recovery from the Labrador interconnected customers, so to me it's a bit of a leap that you'd proceed to try and phase something in when it's a cost that we don't think is reasonable to recover from that group of customers because you don't agree that it's a fair allocation between the customers of Labrador interconnected and Newfoundland Power.

JOHNSON, Q.C.:

Q. Okay.

MR. FAGAN:

A. So jumping to - I think this is in the context of jumping to the rate design issue too that

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Mr. Brockman was indicating that you could deal with it through rate design rather than necessarily through cost of service because the Board had mentioned that you could deal with the customer impacts through rate design. Now there's been discussion on marginal costs and the issue with Labrador. Labrador's average rate is below marginal cost of fuel - sorry, not marginal cost of fuel, marginal cost of Labrador interconnected system if one viewed marginal cost as the opportunity cost of export sales, but with or without the rural deficit, you could make rate design changes for Labrador interconnected customers for inclining block, for example, that you could - it was mentioned by Mr. Doug Bowman, that you could to deal with that and give customers an efficient price signal without having to burden them with an unfair cost share of the rural deficit. So you can deal - you don't necessarily have to pile the costs on to come up with a reasonable marginal price signal for customers on Labrador interconnected system. With respect to Mr. Brockman's statement, I just don't think the 28 percent increase is

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justified based on trying to recover rural deficit, which we don't believe is a reasonable share for Labrador interconnected.

JOHNSON, Q.C.:

Q. The comment that he makes at one part of his statement is, "Probably would never phase it all in because everything is going to change, so maybe I'd just give you 3 percent and see what happens". If the gave you, like, 3 percent under this scenario, what would happen? Like, where does the rest of the money come from?

MR. FAGAN:

A. I'm not sure what the assumption was there. I got the impression from Mr. Brockman that it would continue to be paid for by Newfoundland Power's customers. Now I may have misinterpreted, but I thought he said that it would continue to be paid for by the customers that are already paying for it.

JOHNSON, Q.C.:

Q. Okay.

MR. FAGAN:

A. That's just my interpretation.

JOHNSON, Q.C.:

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Q. Mr. Fagan, does the rural deficit have anything to do with the marginal cost and rate design studies that are being undertaken by Hydro later this year and next year?

MR. FAGAN:

A. No.

JOHNSON, Q.C.:

Q. In the interest of - this is on the question about information on bills. In the interest of transparency, shouldn't the amount of the rural rate subsidy be shown on the bills of customers who are required to pay it, and also those customers who receive the subsidy, there's been discussion of that throughout the hearing, as you'll recall. I'd like to get Hydro's position on that?

MR. FAGAN:

A. I struggle with it because when I look at 40 percent of the rural deficit is on the island interconnected system, okay, so you've got the people in Baie Verte versus the people in Deer Lake, and so the people in Deer Lake are Newfoundland Power's customers and the people in Baie Verte are Hydro's customers and they're saying, oh, we got a rural subsidy

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that we're putting on your bill, oh, and that's associated with recovering the cost of the customers in Deer Lake, or even use of the term "rural" in the definition of the subsidy, this "urban" versus "rural", I mean, Newfoundland Power has a lot of small rural areas which are smaller than some of Hydro's rural areas, and if you took Newfoundland Power's cost of service study and did it by region, not necessarily their defined regions, but more rural regions - if you said let's take all the communities that are less than 300 people, and let's look at the cost of those, you'd come up with a fairly large rural subsidy on Newfoundland Power's system. So the rural aspect of it, if you wanted to come up with something that says we've got a rate equalization policy surcharge or something like that - I don't know if we'd call it surcharge, but adjustment, and it's reflecting government policy that all customers in Newfoundland and Labrador should have reasonably priced electricity, so we have a sharing of it, something like that may have more appetite, okay, because I don't think

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Newfoundlanders necessarily have this problem with everybody pays a reasonable price, you know, that just because you're in rural you should pay more versus urban, so I think that's more fathomable for me, but not referring to something as a rural subsidy. I think it depends on how it's done. With regard to the people who are not paying the subsidy but receiving the subsidy, I should comment on that. I attended the rural rate inquiry back in '95 and we travelled around the province to a lot of the towns. You go into the towns and you have your town hall meetings, and you're in these towns that have always been resource suppliers to the island, right, fishing villages, and mining towns, and so they're saying, you know, you're using our resources to support the island, and then they're saying, you know, we should get something for that, and you've got the Innu nation and the Inuit, and they're saying it's our lands type thing, so there should be a sharing of resources, you're using our water from Churchill. So to tell them that they're being subsidized, they're often quite offended

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because they view that you're using their resources to support the rest of the province, so there should be something given back too. So it's a tough call with respect to it. When I was with Newfoundland Power back in 1996 there was a proposal to introduce a rural surcharge on the bills. It was opposed by all intervenors at the time, and it was a hot topic in the media. It certainly wasn't very popular, so if something like that was going to be introduced, I think you'd have to be very careful about how it's positioned and the perception of fairness to all parties.

JOHNSON, Q.C.:

Q. Uh-hm. So if it's appropriately described, I take it that the transparency element is good?

MR. FAGAN:

A. I think it's -

JOHNSON, Q.C.:

Q. It's better than no transparency?

MR. FAGAN:

A. I may disagree with Mr. Brockman on a number of items, but I do agree with him with regard to his question on what's the purpose. It doesn't impact with respect to marginal cost,

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it doesn't create an efficiency issue, because you can still price reasonably to reflect marginal cost with and without the rural deficit. So if people believe it's a benefit that customers know that there's an equalization approach with regard to rates across the province, I think most people may actually already somewhat recognize that because Newfoundland Power has the same rate for all its customers, whether they're in small towns or in large towns, so most people know that there's economic differences with regard to the cost to serve customers. I think that may be just a view of people already, so I don't know if there's much of a benefit to it.

JOHNSON, Q.C.:

Q. Dr. Feehan mentioned yesterday that we already make reference to the northern strategic plan and the provincial rebate, and we show that on bills, and presumably that's legitimate use of the billing process to put that information there.

MR. FAGAN:

A. Well, the northern strategic plan would have

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to be put on bills because it's not an approved rate of the Board. It's an adjustment to customers bills in Labrador based on a government directive, so Hydro is required to use its published rates for billing customers in Labrador, so the northern strategic plan is an adjustment to approved rates. So you're required to put that on customers bills. This is more of a cost within the overall cost of service, so I don't think that one necessarily is the same thing as - what was the second one?

JOHNSON, Q.C.:

Q. The second one was the rebate of the harmonized sales tax.

MR. FAGAN:

A. The rebate of the harmonized sales tax, so it was called a residential rebate. Yeah, okay.

JOHNSON, Q.C.:

Q. Yeah.

MR. FAGAN:

A. It was a specific item of a credit to customer's bill. There may be a requirement. There may be requirement from Government to identify it separately from a billing

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perspective. I'm not sure on that, but it's possible it may have been. So there may have been direction on that from Government when it was implemented for the utilities. But they're not quite the same because it's an adjustment that's applying to all customers bills. What we're dealing with here is identifying adjustment which separates one group of customers from another. You're saying take your -- you're paying higher rates for another group of customers to have lower rates, and for the other group of customers, you're saying we're giving -- these other group of customers are giving you a break. So, it's -- they're different. They're different things. So I don't know if you could really apply the same practice to the decision.

JOHNSON, Q.C.:

Q. How aware do you think the customers are? We've seen the statistics in terms of cost of recovery in some of these systems, which is very, very low. I mean, you know, 18 cents on the dollar, 14 cents. You've seen the stats. There's no need to go there. But, how -- in

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what fashion would this type of information be getting to the customers who are being subsidized in fact now, that they're -- that the amount they pay reflects just a small portion of the cost?

MR. FAGAN:

A. I think from the customer perspective, you know, just based on my experience in attending the rural rate inquiry, the -- we were in L'Anse au Loup and the people in L'Anse au Loup were, at the time, paying rates, diesel rates, okay, and -- but the town of Blanc Sablon next door, they're paying Hydro Quebec rates, okay, and so it's really hard for the businesses up there to compete and they're saying, you know, we're paying -- having to pay diesel rates but if someone wants a hotel, they just go over to Blanc Sablon versus the hotel in L'Anse au Clair. So, the customers certainly know about the costs. I mean the average cost to serve a diesel customer is around 80 cents a kilowatt hour. So, everybody knows diesel costs are expensive and based when we were up there, there was -- it wasn't that there was a lack of understanding

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that the cost to serve them was very high, but they were viewing it more from, you know, we're trying to survive here. We're trying to run businesses, raise our families. So they were looking for affordable energy.

So, it's a policy thing and Government made the policy with regard to affordable energy. So, it's a question, do we take that Government policy and then try and go out and tell people more about that Government policy from an equalization, you're being subsidized and you're subsidizing someone else. I don't know. It's difficult because you're somewhat cherry picking with regard to Hydro because you could do the same thing for Newfoundland Power and it's a question really of Newfoundland Power somewhat because it's their customers and the customers in Labrador Interconnected as well, Hydro's. Would they want to be telling their customers that they're -- okay, you're subsidizing rural customers in Labrador, so you're subsidizing -- because I mean some of Newfoundland Power's rural systems cost probably more than some of Hydro's rural interconnected systems, not systems but areas, pockets.

JOHNSON, Q.C.:

Q. I'm struggling with that, with that parallel though.

(10:00 a.m.)

MR. FAGAN:

A. Have you driven down Twillingate? Like I mean, if you drive kilometres, maybe 20-30 kilometres and all you see is poles, right, and then you get to the town. So, there's areas like that. I mean, I'm from St. Joseph's out in St. Mary's Bay and we had a fish plant which it load was growing, so they had to come upgrade the substation. Well, the fish plant closed. So the whole feeder is upgraded. You got a new substation. Currently there's probably maybe less than 100 residents, most of them are seasonal. So, you go look at that and then you go look at some of Hydro's areas. They're not much different with regard to -- even in the diesel areas sometimes that you got to go upgrade the diesel because there's a fish plant goes in. But that could happen in interconnected systems as well and then the fish plants

close. So, the difference between Newfoundland Power service areas in rural and Hydro's service areas on the interconnected system in rural, there's not much difference.

JOHNSON, Q.C.:

Q. But the case of Newfoundland Power's service area, I mean, that's probably replicated across the country. Like in say Nova Scotia, they've got small areas, you know, on the south shore of Nova Scotia versus Halifax, Dartmouth, and so I can see the idea of well, you wouldn't necessarily, you know, put that on a Nova Scotia power bill or a Newfoundland Power bill, but I think here, aren't we talking about something of a different magnitude altogether?

MR. FAGAN:

A. I don't think so, from the Island Interconnected because historically, I think it was -- I don't know if it was 1958 when they started, the Government was supporting the development of power and the diesel systems came into play and so eventually they started interconnecting and transferring some of these small systems over to Newfoundland

Power. So, as they were interconnected, some towns became Newfoundland Power's customers and I think the principle was when it was economic to do so, and they wouldn't cause a big increase in Newfoundland Power's rates. So, the practice stopped. So some of them stayed with Hydro, and I'm not sure why the practice stopped, okay, but a number of the systems stayed with Hydro to remain interconnected. Had they all moved to Newfoundland Power, the Island Interconnected, well 40 percent of the rural deficit -- now the cost to serve may not be exactly the same, there's probably some duplication, but Newfoundland Power would say have an income tax expense from its customer where Hydro doesn't. So the average cost may not be that much different. If the Island Interconnected systems moved to Newfoundland Power, they wouldn't be part of the rural deficit. They'd be part of Newfoundland Power's rate. So that would be 25 million off the rural deficit.

So it's -- so from an Island interconnected perspective and looking at the rural deficit, and it's a large part of the

rural deficit, identifying one group just because they're Hydro's rural customers on the Island interconnected versus Newfoundland Power's and identifying that as a subsidized group, it's not much different than breaking Newfoundland Power's cost of service study into regions and coming up with rural deficits itself. That's my view on it.

JOHNSON, Q.C.:

Q. Where the amount of the rural deficit is both so large and so unconnected to the cost that these customers are imposing on the system, in terms of, you know, it's not cost based, the 64 million dollars in terms of the group -

MR. FAGAN:

A. It's a large percentage, yes.

JOHNSON, Q.C.:

Q. Yes, and would there not be like more of a case where the customer in Labrador interconnected and on the Island interconnected, they're not responsible for these costs. In that circumstance, given the largeness of it, is there not more of a case to say, look, we should be transparent about this; I mean, this is not something that just arises through normal balancing and cost of service between customer groups on a system?

MR. FAGAN:

A. It is a large deficit. No one can doubt the magnitude of the rural deficit, I mean, because it's -- just the size of it has created all this debate before the Board. I'd only be careful about the messaging, that if you were going to do it, I think there should be some discussion with Newfoundland Power first with respect to it because it's their customers that you're putting the message out to and if you create this new message, it's Newfoundland Power is going to get most of the calls with regard to "explain this new thing on my bill. Why am I subsidizing these other customers, these Hydro rural customers on Isolated systems?" So it's just you don't want to create unintended consequences. So I think maybe some research prior to doing it, that you do some focus groups with customers, get their opinion on it before you'd move on something like that. I just wouldn't want to do it, arbitrarily select it, and then have to live with the results that were unforeseen.

JOHNSON, Q.C.:

Q. Following up on the issue of the quantum of the rural deficit, in 2015 it was 64 -- forecast 64 million, in that vicinity. Now I understand -- if we could bring up CA-NLH-207, Revision 2 -- this contains -- yeah, Attachment 1, I'm sorry. If you could go down the graph a little bit or the table, I should say. This was filed yesterday and I take it it's an extract from the 2014 Annual Report on the Rural Deficit that Hydro filed?

MR. FAGAN:

A. That's correct.

JOHNSON, Q.C.:

Q. Okay. So in fact, the forecast deficit number is filed with the Board for '16, '17 and '18?

MR. FAGAN:

A. Yes. '16 and '17 are legitimate forecast. There's uncertainty of the numbers with regard to '18/19, so it's assumed to be the same as '17 for purposes of this.

JOHNSON, Q.C.:

Q. Okay. So I guess my question would be we're forecasting the rural deficit to fall in 2016 to 61 million and 2017 to 59 million. Is that

mainly fuel oriented?

MR. FAGAN:

A. Yeah, I questioned someone on that last night and I was told it's mainly fuel. I believe there may have been a reduction, slight reduction -- this was based on a fuel price forecast of the $93 and I believe -- and of course, the accompanying diesel forecast at the time. So, when we get out to '16 and -- we get out to '17, '16 and '17, the fuel price was slightly less.

JOHNSON, Q.C.:

Q. Okay. So I guess the -- I guess my question would be that would Hydro be over collecting from customers if the 2015 test year is based on 64,070,000, according to this table for 2015? Would we be -- Hydro be over collecting as rates go into effect?

MR. FAGAN:

A. It's also my understanding that this reflects a lower ROE in future years because this -- we call it a fallout calculation. That it's assuming the rates that are proposed go into play, but additional costs would also be incurred and it's not effectively maintaining

Hydro's return on equity at 8.8 percent for the subsequent years. So that's actually -- if you were redoing a test year every year, then you'd maintain the ROE at 8.8 percent and that rural deficit number would be higher. But Hydro wouldn't be achieving that rural deficit -- that return on equity and that's causing somewhat of a contributing to a reduction in the rural deficit.

JOHNSON, Q.C.:

Q. But I guess, as a matter of fact, the rates will be reflecting a rural deficit of 64 million, but the anticipated rural deficit will be about three to four million dollars less in 2016 and 2017 respectively?

MR. FAGAN:

A. To achieve the 8.8 percent ROE in the proposed return on rate base, the rural deficit would be 64 million. There's other cost changes going forward in '16 and '17 and the return on equity, it's an output rather than an input into deriving the numbers, and so that combined with the fuel price decline would be -- would contribute to that. Now, Hydro's proposed a deferral account for fuel price

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differences on the Isolated systems.

Now, I believe Hydro's return on equity or return on rate base has been proposed to be plus or minus 20 basis points, which is equivalent to approximately three million dollars, plus or minus three to three and a half million dollars, that's my understanding. So, if -- when this was prepared, the fuel price was based on $93 a barrel for No. 6 fuel, which is fairly correlated to the cost of diesel fuel. If fuel price declined and Hydro's deferral account was approved, then the savings associated with the fuel price decline would go back to customers through the deferral account.

Now, Hydro is at a position where fuel costs have declined, so we're down to a No. 6 of around $70 a barrel and correspondingly, the No. 2 serving diesel areas would also decline. So we're in a lower area now and if the Board approved rates based on these lower fuel costs without the deferral account and fuel costs go up, then Hydro would effectively have to eat those costs which will reduce return. If the deferral account was approved,

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then the additional costs would be recovered. So, when you don't have a deferral account to deal with fuel cost variances, as we currently don't on Isolated systems, there's a risk associated with it. If you're going in high where we got to do a fuel price forecast, Hydro would keep the savings. If you're going in low, Hydro will have to incur the costs as they increase.

I mean, when Hydro filed this application in November 2014, it was mentioned it was based on the 93.32 and I think the No. 2 fuel cost in that was 18.8 million dollars. Hydro filed an interim rate application only a few months later based on a $63 a barrel No. 6 fuel and we also reflected 3.6 million savings, I believe, of No. 2 fuel just in a few months, which is more than the full 20 basis points of return. So this just contributes to the argument with respect to having a deferral account to deal with fuel cost variances in Isolated systems. If you want the savings with regard to that fuel price difference, deferral account would be appropriate.

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JOHNSON, Q.C.:
Q. So Mr. Fagan, the numbers that we're seeing for forecast 2016 and 2017, these are stale numbers?
MR. FAGAN:
A. Well, they're based on the forecast at the time of filing the return, yes.
JOHNSON, Q.C.:
Q. Right, and would a more recent forecast be available for the 2016 and 2017 forecast rural deficits?
MR. FAGAN:
A. I think we would -- in order to do that, you'd have to redo the whole cost of service study based on complete updated costs because rural deficit isn't just fuel costs, it's allocation of all your costs, your overheads, all your operating costs in the diesel areas as well. So, it may be higher on fuel in this particular forecast, but if you update it, it may not necessarily go down because other costs may go up to offset it. But, no, I would say there's not right now because we don't have an updated cost of service study reflecting new 2016 numbers to provide and

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estimate.
JOHNSON, Q.C.:
Q. Would it be possible to file a forecast for 2016 and 2017, the change that would be made if you just adjusted the fuel?
MR. FAGAN:
A. I can inquire.
JOHNSON, Q.C.:
Q. Okay.
MR. FAGAN:
A. Okay, I'll check.
JOHNSON, Q.C.:
Q. Turning to specifically assigned O&M for a moment, Mr. Fagan, could I bring you to the rate schedule section of the application, specifically page six of 46? Yeah, there we are, okay.
So just to understand here, this is your -- the rate schedules attached to your Application and it provides the specifically assigned charges for customer plant and service that is specifically assigned to the customer and we see: Corner Brook Pulp and Paper, 891,000; North Atlantic Refinery Limited 91,000; Teck 208; and Vale 499. Can

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you confirm, Mr. Fagan, that Hydro is seeking -- is actually seeking approval from the Board for the charges that are set out here in this schedule?

MR. FAGAN:

A. That's reflected in the Application, yes.

JOHNSON, Q.C.:

Q. That's right. So that's what are you seeking, Hydro is seeking in this Application? That's not been amended and not intended to be amended?

MR. FAGAN:

A. Well, Hydro's filed its application based on its standard approach to preparing the cost of service, I'd say with the exception probably of the rural deficit, which is proposed for change. But there's been additional evidence obviously provided by Mr. Dean and there was a number of RFIs on this matter and if we can bring up Vale-083, please?

So Mr. Dean has identified the concern with respect to, I guess, the intuitive effect that because assets, new assets in the current cost of service methodology are reflecting a higher proportion of O&M which is certainly

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not intuitive because the customers got a new asset, so higher O&M gets allocated to them and it's based on the fact that the methodology uses the O&M as a percentage of the original cost. So, Hydro hasn't reflected -- amended this application to reflect that. I mean, Mr. Greneman has recognized that there's -- Mr. Dean's proposal is credible, I think, that it's -- adjusting the numbers to real dollars in calculating the O&M percentage would probably be fairer.

But this is somewhat of a new issue before the Board and I know Hydro's employed the same calculation approach to its O&M percentages historically, but the fact that when you've got a new customer comes on just before a test year and you've got this investment of 10 or 11 million dollars for an industrial customer, all of a sudden this kind of jumped out at us. So it wasn't -- I think it was probably not reviewed closely enough with regard to the components and whether it was a reasonable number upfront, but I think Hydro recognizes that it's probably not really a fair approach with respect to specifically

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assigned charges.

We haven't filed an application to change anything as of yet, but I don't know every time we get into a discussion of a particular issue before the Board and we realize that something else has merit and we're supportive of it, should we automatically amend the application or just say, "yeah, his recommendation has merit. The Board should consider it and in their final order of the Board."

So, what Mr. Dean has presented seems like a reasonable approach and if we bring up -- actually, if we go to that table for a minute near the end of that, so if you do a bit of comparison of some of the dollars. The direct transmission O&M expense, I think maybe the last table summarizes it all. Yeah, total transmission, so we've got direct as well as administration and channel. So, we see -- now this is only the 212 versus the 70.

JOHNSON, Q.C.:

Q. What RFI is this one? Okay.

MR. FAGAN:

A. Is there another table, Table 4, please?

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Specifically assigned O&M, okay. So in our cost of service study, if we go to the third column under the first section, per 2015 cost of service study. Vale has 436,000 O&M costs allocated to it. Now these are legitimate O&M costs of Hydro with respect to the test year because we've got the full O&M costs in the cost of service study but it's been allocated among the parties. It's not like the O&M costs don't exist. It's just the way we're allocating it among the parties. So we're allocating to the specifically assigned assets here, 2.5 million, which is the third column at the bottom. And of that, Vale is getting 436,000 and that's driven materially because of the newness of the assets.

So if we go over to the alternate method which adjusts for real dollars, so it's real dollars rather than original costs, it's 145,000 for Vale versus 436. So the magnitude of the difference is pretty large. It almost reminds me somewhat of the rural deficit argument that we look at it and say the difference is just so large that, you know, it begs the question is it reasonable. And there's been some discussion about whether there's any precedent for dealing with this before the Board. I wonder if you could bring up Vale-125 for a minute, please?

MS. GRAY:

Q. 125?

MR. FAGAN:

A. Yeah, 125 is the last RFI, I believe, from Vale. No, the -- I don't know if it's on the Board's website yet, but there is a Vale-125. Okay. So there's a question here about the use of indexing approved by the Board in the past, and the -- so if we just move down to the response?

So Newfoundland Power's contribution in aid of construction policy or CIAC policy in determining its charge to customers that pay contributions, it's based on a capital cost but also includes a O&M portion assumed over the life of the asset, and in determining the O&M portion, because actually the approach that Mr. Dean is proposing is consistent with the approach used and approved by the Board for determining the charges for Newfoundland Power that they use. They index the costs

upon the Handy-Whitman index to the original cost of distribution index -- of the distribution asset, sorry. So, because the approach that Hydro uses now for specifically assigned charges is consistent with what was used in Newfoundland Power's CIAC policy up to I think September of 1997 and there was a change in the policy at that time to move to the indexing approach. The O&M percentages were materially higher for the customers paying contributions and it was determined that it should be changed, so it was changed in 1997 for Newfoundland Power.

So what he's presenting has been dealt with in a different context before but the principle is the same.

JOHNSON, Q.C.:

Q. Okay. Let's just backup for a bit now, because you've jumped right into it and made a case for Vale.

MR. FAGAN:

A. All I said was that the application hasn't been amended, but the Board can rule on it without Hydro amending the application.

JOHNSON, Q.C.:

Q. Okay, very good. Now, Mr. Fagan, when Hydro undertook construction of the Vale connection facilities, do you know whether an estimate of the specifically assigned capital and O&M costs were provided to Vale?

MR. FAGAN:

A. I don't know.

JOHNSON, Q.C.:

Q. Okay. Who would know that?

MR. FAGAN:

A. It could be Mr. Humphries.

JOHNSON, Q.C.:

Q. Okay. And are you familiar with Hydro's procedure relating to new customer connections for like an industrial customer? What's the procedure that happens?

MR. FAGAN:

A. Well, generally -- now I'm not directly involved, but I can -- based on my knowledge, I'll give you my best response. New industrial customers, the most recent practice certainly is that new industrial customers come on and pay full contribution for their assets. So Vale paid full contribution effectively for the new assets provided

initially to serve them, that are specifically assigned assets.

JOHNSON, Q.C.:

Q. Okay.

MR. FAGAN:

A. So specifically assigned charges for customers, when the assets are provided by Hydro, for example, with the frequency converter for Corner Brook Pulp and Paper which was many years ago, and all the assets and the investment over time, Hydro -- the specifically assigned charge is based on a return on the asset plus depreciation, plus O&M charges. When a customer pays a contribution to recover the capital investment, then there's no return and there's no depreciation. The customer only pays the specifically assigned charges.

As capital is invested over time for the assets, if the customer doesn't pay for it and Hydro pays for it, it goes in and determines a return over time. But, for Vale, the vast majority of the charge is associated with the O&M because pretty well all the assets on Hydro's books would pretty well close to have

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been almost fully paid for by Vale. So, that's just -- so that's -- I just wanted to give a background on the approach.

With regard to the -- so in Vale's case, which I think also probably would have been Teck's at the end of the day, they would have paid their full contribution on the assets. So, what they've been paying for would be O&M charges.

JOHNSON, Q.C.:

Q. Okay. But to your knowledge, part of Hydro's procedure in dealing with a Teck or a Vale would be to actually say "now, listen, this is how O&M costs are calculated and this is what they would likely be"? Would that be your understanding?

MR. FAGAN:

A. Well, the customers are certainly informed that they've got to pay O&M. With regard to the detail of the calculation of O&M, it'd never get into the detail of whether it would have been based on the original cost versus the real dollars aspect of it. So, the principle of the specifically assigned charges is that they're going to be paying it. The

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customers are aware of that.

JOHNSON, Q.C.:

Q. And they would be told that it would be in accordance with Board approved methodology? Wouldn't they be told that?

MR. FAGAN:

A. Oh, I expect so, yes.

JOHNSON, Q.C.:

Q. Yeah, okay. So we can follow up some of that with Mr. Humphries.

MR. FAGAN:

A. But I mean, at this stage, we're considering what the Board approved methodology would be.

JOHNSON, Q.C.:

Q. Right, and it would be your evidence, as we've heard from others, that Hydro's rules on O&M contributions, that would be -- for specifically assigned assets, that would be generally in keeping with what we see in other jurisdictions? Is that right?

MR. FAGAN:

A. Well, I asked Mr. Greneman to review and so he did some investigation and he had difficulty finding information with regard to specifically assigned charges for Industrial

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Customers. Hydro's approach of allocating O&M within the cost of service study, excluding the issue of specifically assigned charges, according to Mr. Greneman is clearly consistent with what's done in industry practice. Specifically assigned charges and recovering O&M costs for industrial customers, sometimes it's my understanding is done differently. Sometimes you may have an agreement with a customer that you could have it that you'll do the O&M and you bill them on an as-required basis, and there may be some fixed amount that you're trying to recover your administration and general costs type of thing. So you may have a fixed amount, but you may have a premium based on the amount required, which would be outside of a cost of service study allocation. That could cause O&M costs to go up or down, depending on the amount of activity over the years. If customers want more stability with regard to what their O&M would be, you could have it set up so it comes out of the cost of service and so you pretty well know what it's going to be between test years. So there's different

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approaches to dealing with it. He had difficulty finding much information on practices in other jurisdictions with respect to industrial customers.

JOHNSON, Q.C.:

Q. And certainly was not able to find an instance where Mr. Dean's methodology had been adopted in another jurisdiction for Industrial Customers?

MR. FAGAN:

A. No, he wasn't.

JOHNSON, Q.C.:

Q. Right. And so just to understand, now Mr. Dean is Vale's witness. He's indicated he's not an expert witness but he has come up with this new methodology and he would like that to be implemented in this GRA or he can live with the Hydro $150,000 figure. So are you telling us that Hydro is now comfortable with the Board just getting on with it and making a change to the methodology now in this proceeding?

MR. FAGAN:

A. Well, I wasn't close to Hydro's methodology on specifically assigned O&M when I moved over to

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Hydro. When Mr. Dean identified his concern in his evidence, I looked at it, and I said "oh, I've seen that before" because I recalled the CIAC policy issue that we recognized the problem and made the change back in 1997. So, I saw the merits of his position at that time, but I wasn't close -- I wasn't involved with regard to the original filing with respect to the standard approach, so it wasn't looked at closely before Hydro filed its application. I think what he's provided is a reasonable thing, a reasonable certainly starting point and if we want to look at it further in the cost of service methodology review, we've actually put that in our scope of our review.

JOHNSON, Q.C.:

Q. Yeah.

MR. FAGAN:

A. But that's probably not a bad starting point.

JOHNSON, Q.C.:

Q. Yeah, and that's what Mr. Greneman said. It's the discussion piece, but I mean, by no -- I mean, I never heard Mr. Greneman saying well now let's get on with it here now, Board, make this change for the Vale.

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MR. FAGAN:

A. With respect to Mr. Greneman's statement on discussion piece, he was referring to his rebuttal evidence is my understanding. His rebuttal evidence where he presented an adjustment approach going back to 2007 as a discussion piece. I was under the impression that he thought Mr. Dean's approach was reasonable, but you can check the transcript.

JOHNSON, Q.C.:

Q. But let me just get this right now. To answer my question, Mr. Fagan, is Hydro now in favour in this proceeding of having the Board make a change to the specifically assigned cost methodology such as suggested by Mr. Dean?

(10:30 a.m.)

MR. FAGAN:

A. Hydro believes Mr. Dean's approach would be a good approach to start with until it can be further reviewed in the cost of service methodology hearing, and so change the approach now and use that until it's further reviewed in the cost of service methodology hearing.

JOHNSON, Q.C.:

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Q. Okay. So we would go, what, to Mr. Dean's $85,000 a year? Is that what we'd do now?

MR. FAGAN:

A. Let's go back to the RFI, Vale-083. No, it's not $85,000 a year. Table 4 would show the specifically assigned O&M portion of the charge being $145,000.

JOHNSON, Q.C.:

Q. Yeah, but that's the method that Hydro came back with, but I think Mr. Dean confirmed in his evidence that he thought it was -- I thought it was 87,000 or something.

MR. FAGAN:

A. Mr. Dean didn't have all the numbers to do the analysis. Actually, when the RFI started, Hydro had difficulty finding the data that Mr. Dean was requesting to do the analysis. We checked with someone who was retired and they actually told us where we could find the information. So we managed to do what Mr. Dean requested because we found the data that he was requesting us to do the analysis on. So, this is applying Mr. Dean's analysis to I'll call it more full data and Mr. Dean was coming up with some estimates, I understand.

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JOHNSON, Q.C.:

Q. Okay. And I take it that to your point, you indicated a few moments ago that the total cost of the O&M of 436,000, that doesn't go away. It's just that Vale pays less of it?

MR. FAGAN:

A. Yes, it's a real O&M cost incurred by Hydro that's currently being considered specifically assigned, but based on the information that we looked at here, one review that rather than having 2.5 million dollars of O&M costs as the total at column three being specifically assigned O&M, we think it would be more reasonable to have 1.9 million which is the total at the bottom being specifically assigned. So Hydro would revise its cost of service to reflect that for purposes of determining specifically assigned charges. I don't know if I lost you there, Mr. Johnson.

JOHNSON, Q.C.:

Q. No, you didn't lose me. So, then the balance then, that just gets picked up by Newfoundland Power and these other customers. They pick up the extra 600,000 bucks?

MR. FAGAN:

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A. Well, the other 600 -

JOHNSON, Q.C.:

Q. In large part.

MR. FAGAN:

A. The other 600,000 would go into the pot to be allocated as common, which would be mostly to Newfoundland Power, some to Hydro rural, some to Industrials as well, but yes, the same as other costs. Because Mr. Dean's analysis or his methodology would indicate that those were putting too much costs in has specifically assigned from an O&M perspective and they should be common.

JOHNSON, Q.C.:

Q. Has Hydro called Vale up in Sudbury to see how they do it up there? Mr. Dean, he's been retained by Vale. He told us he didn't call them and find that out. Do you guys know that?

MR. FAGAN:

A. No.

JOHNSON, Q.C.:

Q. No. And has Hydro determined -- has Hydro done any studies comparing O&M costs of facilities that are from one to five years of

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age or from five to ten years of age, 10 to 15, et cetera, to determine the cost differences of things like terminal stations, transformers and transmission lines?

MR. FAGAN:

A. Ask that of maybe the operations panel.

JOHNSON, Q.C.:

Q. You're not aware of though in terms of your analysis of the O&M issue?

MR. FAGAN:

A. No.

JOHNSON, Q.C.:

Q. No. And Mr. Greneman wasn't?

MR. FAGAN:

A. No.

JOHNSON, Q.C.:

Q. Mr. Fagan, it just seems to me that, you know, this is a fairly significant change that you'd be inviting the Board to make when it's -- I don't think it's -- I put it to you, I don't think it's been adequately studied. If you can't say that you've even looked at the differences in O&M costs from one to five or five to ten, you know, we don't know -- I think there's a number of things we don't know

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about this and I'm just wondering wouldn't this really be better just properly studied? I mean, maybe Vale has a point; maybe they don't. But wouldn't it be better looked at in the cost of service study?

MR. FAGAN:

A. Well, I know when we -- I only be from my experience that we looked at it when we were doing it at Newfoundland Power with respect to contributions in aid of construction and we thought using real dollars in the analysis made more sense, and so the change was approved, and so the principle of the O&M versus the O&M approach proposed by Mr. Dean is exactly the same. So, I think to me it's more of -- there's clearly some issues. There's issues with the current methodology in that it's charging more O&M to a customer with new assets which one would indicate we'd like to get less O&M. So the -- so that, just that issue itself, and that's why that change was made at Newfoundland Power, that you were charging too much O&M costs to customers that were paying contributions, which is effectively a specifically assigned asset when

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you're charging someone a contribution for it. So it's the same principle.

So, I think from a principle perspective, starting with this, like if -- here's my struggle. Vale doesn't pay a specifically assigned charge right now. So you're starting them out with a $436,000 specifically assigned charge on a methodology which you really can't support because it's based on a presumption that because they've got new assets which are higher costs than the original cost of the assets that are there for 20 or 30 years that they should pay a higher O&M charge, and it's really hard to defend that. I mean, to me, being able to explain the rationale of a rate to a customer and say "okay, this is why this rate makes sense" is an important component of communicating with the customer. If you can't defend your approach to the charge, I'd have a hard time proposing it.

JOHNSON, Q.C.:

Q. But I mean, again though, you're making that statement in the context of Hydro not having, to your knowledge, studied whether there's a difference in O&M costs at various time

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intervals on the equipment in question.
MR. FAGAN:
A. Well, even if you did, which I expect you'd find the difference, I think there was -- when Teck Resources announced that they were closing their operations, I phoned out to one of our operations people and said "okay, what will we do with that Teck line because you know, now that the business is closing?" and he said "gee," he said, you know, "why would we take it down." He said "it's pretty well a new line. We haven't even started our inspections on that yet. We do this one flyover once a year type thing. So" he said "there's very little operating and maintenance costs associated with it." He said "we're just starting to get into that now going forward." So, he said "I don't know why you'd want to go taking it down now. I mean, it could be used for some other business may want to start" type thing.
So, when -- just based on my discussions with the field people about O&M practices for transmission lines would somewhat support the concept that the schedule which Mr. -- the

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operations panel could probably talk to more that you don't have a lot of O&M for the initial years for your transmission assets. So it just doesn't seem practical to me that you're ramping up your O&M costs charging to the customer in advance of really implementing your maintenance plan.
JOHNSON, Q.C.:
Q. You know, I appreciate the anecdote, Mr. Fagan, but it's hardly -
MR. FAGAN:
A. It's the truth.
JOHNSON, Q.C.:
Q. - a substitute for analysis though.
MR. FAGAN:
A. Well, the analysis has been done -- like I mentioned, if we go to Vale-125 that the methodology has been changed to reflect real dollars because of the problem on the CIAC policy at Newfoundland Power because of the problem with using original cost in the calculation. So that principle has been accepted in this jurisdiction and approved by the Board. So, I don't think the principle changes whether it's for contribution in aid

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of construction versus for O&M for a new customer coming on that's an industrial customer of Hydro.
JOHNSON, Q.C.:
Q. So in essence, you're saying do it and then we'll study in cost of service as well?
MR. FAGAN:
A. All I'm saying is that the current methodology that we have got presented to the Board in the application appears to have a flaw based on what's been analyzed already with respect to determining Newfoundland Power's contribution policy and so, just hitting the customer with the charge recognizing the flaw in the policy doesn't seem to be a reasonable approach. Mr. Dean's method, which is consistent with the methodology that's used by Newfoundland Power, is probably a good starting point until we do a more comprehensive review of specifically assigned charges for industrial customers as part of the cost of service methodology review.
JOHNSON, Q.C.:
Q. Mr. Fagan, I don't know if we should take this up with another panel, perhaps you can tell

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me, but what does Hydro's average OM&A represent as a percentage of capital costs on the transmission system? Would that be best for Humphries, the Humphries panel?
MR. FAGAN:
A. Humphries or Mr. Henderson, yeah.
JOHNSON, Q.C.:
Q. Have you had cause to look at how Hydro's average OM&A as a percentage of capital cost compares to Mr. Dean's proposed methodology?
MR. FAGAN:
A. Well, the actual analysis in Mr. Dean's methodology is really similar to what you're talking about because what we're dealing with here is our test year operating and maintenance relative to the historical capital expenditures put in the same dollar terms. So to me, that is really, from a long-term average, what you're talking about, because the OM&A that Hydro is putting forward in its test year is not solely associated with its current capital expenditures. It's related -- it's more related to historic capital expenditures. So, what we're presenting here with regard to expressing it in real dollars

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would be a reasonable representation of what the operating and maintenance costs are as a percentage of historical asset investment expressed in the same dollar terms.

JOHNSON, Q.C.:

Q. The service agreement with Vale is attached to Order P.U. 6(2012), in particular Schedule A of that particular Board Order. Mr. Fagan, the ramp-up period is defined in 1.01(s) means "the time required from the start of processing of ore concentrate to the time that the customer's Long Harbour facilities meets its full capacity as determined in accordance with Article 2.06(c) and (f)". So do you know when the ramp-up period started?

MR. FAGAN:

A. That issue is probably better for Mr. Humphries' panel.

JOHNSON, Q.C.:

Q. Okay.

MR. FAGAN:

A. Now I'm familiar with the fact that they're not paying a firm -- establishing a firm demand that's being reset as they ramp up, but with respect to the details on the actual

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ramp-up period, Mr. Humphries' panel.

JOHNSON, Q.C.:

Q. Okay. And he could also tell us when the ramp-up period would have ended?

MR. FAGAN:

A. Yes.

JOHNSON, Q.C.:

Q. Okay. Do you know if the ramp-up period has ended?

MR. FAGAN:

A. No, I'm pretty sure it hasn't.

JOHNSON, Q.C.:

Q. It hasn't, okay.

MR. FAGAN:

A. But it's best to check with him, but I don't think so.

JOHNSON, Q.C.:

Q. Okay. Now you've indicated that Teck Resources is closing operations. Are they closing or are they closed or what's the status of that?

MR. FAGAN:

A. It's my understanding that they're -- well, they've reduced -- they're no longer in production, so I thought it's more of a clean-

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up phase, environmental clean up for the next year or so.

(10:45 a.m.)

JOHNSON, Q.C.:

Q. Okay. I notice under the agreement with Vale in 15.04(b) that it indicates that "subject to Article 10, if the customer voluntarily or forcibly abandons its operations, commits an act of bankruptcy or liquidates its assets, then there shall be forthwith become due and payable to Hydro by the customer a stipulated and liquidated damages without burden of proof thereof, a lump sum equal to .85 of its then billing demand for firm power at the firm power demand charge multiplied by 24, plus the remaining net book value of the specifically assigned plant less its salvage value net of any contributions towards that value made by the customer."

Is there a similar provision in the Teck agreement, do you know?

MR. FAGAN:

A. I'm not the best person to talk about the agreements, but I would anticipate there probably is, but Mr. Humphries would probably

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be the best one to talk to that.

JOHNSON, Q.C.:

Q. Okay.

MR. FAGAN:

A. I think that's probably more of a standard term.

JOHNSON, Q.C.:

Q. Okay. Mr. Fagan, turning for a moment to the Corner Brook Pulp and Paper co-generation costs and just a few very brief questions on that. We've heard that these costs are in the cost of service study for 2015.

MR. FAGAN:

A. That's correct.

JOHNSON, Q.C.:

Q. And these costs are allocated to customers as common? Is that right?

MR. FAGAN:

A. That's correct.

JOHNSON, Q.C.:

Q. Okay. And it's around 10 million dollars in the test year? Is that right?

MR. FAGAN:

A. That's correct. I think it's in Schedule 6 of regulated activities.

JOHNSON, Q.C.:
Q. Okay. And so, these would be costs of course that'll be picked up by Newfoundland Power, Vale, North Atlantic Refinery, in due course?
MR. FAGAN:
A. Well, they're purchased power costs.
JOHNSON, Q.C.:
Q. Yes.
MR. FAGAN:
A. So, each year. They're reflected in the test year.
JOHNSON, Q.C.:
Q. Okay. And would you be able to provide an undertaking indicating what each of Newfoundland Power, Vale, and NARL will be picking up from that purchase cost?
MR. FAGAN:
A. I can. But I can give you a high level description, I mean, if we brought up, I believe it's Schedule 6 to the regulated activity. Okay. The ten million -- I'm okay with -- move over to the right.
The 10,281,000 is the purchase power cost reflected in the test year. Now there's 51 gigawatt hours forecast, so that's

approximately 20 cents per kilowatt hour. So that's the purchase power price in the test year. Now, the purchases from Corner Brook co-gen reduce the purchases in the test year assumed for Holyrood and the average Holyrood cost is around 15 cents per kilowatt hour in the test year, based on the $93 a barrel. So there's a five cent premium with respect to the purchases for Corner Brook co-gen. So if you took the five cent premium and applied it to the 51 gigawatt hours, you get about 2.5 million dollars and I think in the test year, the revenue requirement on the Island Interconnected system is around 620 million dollars.
So it's about a .4 percent impact, which would generally be pretty close across all customers because I think the purchases from Corner Brook co-gen and the purchases from Nalcor, purchases in general, have been classified based on system load factor. So, it's split between demand and energy and system load factors. So, it's spread over both demand and energy. So the .4 percent is a fairly good number on what the impact on

customer rates is of the premium associated with purchases from Corner Brook co-gen.
JOHNSON, Q.C.:
Q. But the premium was actually larger than five cents because, as you say, the 15 cent Holyrood figure is based on the $92 a barrel.
MR. FAGAN:
A. In the application, yes.
JOHNSON, Q.C.:
Q. Yes.
MR. FAGAN:
A. Yes. Now, if the price drops to $70, so you're down closer to slightly less than 12 cents, so the premium would be more like eight in that particular circumstance.
JOHNSON, Q.C.:
Q. Yes.
MR. FAGAN:
A. So then you're into about four million dollars over the six -
JOHNSON, Q.C.:
Q. Right.
MR. FAGAN:
A. So then you're into about .6, so between .4 to .65 percent.

JOHNSON, Q.C.:
Q. Yes. So based upon what Hydro believes will be the forecast for No. 6 fuel that'll be filed shortly, could Hydro undertake to put on the record what portion Newfoundland Power, Vale, North Atlantic will be paying out of that?
MR. FAGAN:
A. Actually I should correct something, because if the Holyrood price drops, okay, the price for Corner Brook co-gen would probably drop as well because I believe it's based on No. 6 fuel as part of a component of the price. So, it wouldn't necessarily -- the premium wouldn't necessarily increase because of the price decline. I think the Corner Brook co-gen number might decline as well, but the operations -- sorry, the system planning panel would know that better, but we can certainly get you the details. So that .4 may be still reasonable.
JOHNSON, Q.C.:
Q. Okay. So you can undertake, can you, to provide what portion or how much in dollar terms Newfoundland Power, Vale, North Atlantic

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will be paying based both on test year and the projected fuel price?

MR. FAGAN:

A. Yes.

JOHNSON, Q.C.:

Q. Okay.

MS. GLYNN:

Q. Noted on the record.

JOHNSON, Q.C.:

Q. Okay. And of course, we've seen that Vale's load is going to be increasing fairly materially over the next couple of years, so with that, I guess, we can expect that Vale will be picking up an increasing amount of this cost as time goes on?

MR. FAGAN:

A. Well, the test year sets the rate, so from now until the next rate setting process, unless there's a deferral account to deal with cost variances associated with purchases, what's in the test year would be the rate for purposes of -- as a proportion of their bill. But certainly if they're using more, the dollar effect would be different.

JOHNSON, Q.C.:

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Q. Yes. But certainly by the time the next GRA rolls around and Vale's load is fully up, then they'll be -- they can expect to be paying more for this expensive power?

MR. FAGAN:

A. Certainly the dollar effect would be more.

JOHNSON, Q.C.:

Q. Yeah. Now -

MR. FAGAN:

A. The percentage change may not be.

JOHNSON, Q.C.:

Q. Okay. Now as regards to supply costs mechanisms, we understand, Mr. Fagan, that following the conclusion of the GRA -- and this is set out at paragraph 4.24 of the rates and regulations evidence.

MR. FAGAN:

A. Just a second now. Okay, I'm there. Did you say page 4.24?

JOHNSON, Q.C.:

Q. No, I'm sorry, paragraph 4.2.4

MS. GRAY:

Q. Page 4.6

MR. FAGAN:

A. Oh, page 4.6, okay. Sorry.

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JOHNSON, Q.C.:

Q. It's 4.6, yeah.

MR. FAGAN:

A. Okay.

JOHNSON, Q.C.:

Q. Starting at line 23 indicates and states actually "following the conclusion of the GRA, Hydro plans to conduct a review of the requirements of regulatory mechanisms to deal with variability in supply costs. Hydro plans on filing a report to the Board prior to the end of 2016 on its review of regulatory mechanisms to provide for supply cost recovery."

Mr. Fagan, if Hydro is going to be reviewing requirements for these regulatory mechanisms in the coming months, will that review also be considering how these regulatory mechanisms mesh with Hydro's currently directed ROE?

MR. FAGAN:

A. That was not the intention. The intention is to review the cost variances. I expect -- I wouldn't say ROE, but the -- I mentioned earlier that 20 basis points, so plus or minus

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20 basis points on return on rate base. 20 basis points is equivalent to, you know, between three, three and a half million dollars type thing. So, when looking at supply cost mechanisms, you want to be looking at it in light of your range of return. So, the variability of the costs and the impact it would have on your rate of return on rate base for costs that are beyond your control, so I wouldn't say we're reviewing it in light of the fact that Government has directed us to earn an 8.8 ROE, but we'll be considering the range of return on rate base in looking at whether it's necessary to have certain supply cost recovery mechanisms.

JOHNSON, Q.C.:

Q. But like to the extent that some of these proposed mechanisms transfer risk away from Hydro and onto the customer, would you not think it sensible to analyze the appropriateness of that, given the fact that Hydro's ROE has dramatically increased from that which the Board found just and reasonable when it last determined it?

MR. FAGAN:

A. I think I'd have to push that one onto our Finance panel. Mr. Scott Pelley would probably answer that one. But our review would be focused more on supply cost variances that would be beyond Hydro's control. So, I mean, there's been a number of them presented in this proceeding because a lot of the costs that have been -- things have changed since 2007. So there's new costs that Hydro is looking at.

For example, in the energy supply cost deferral for the Island Interconnected system, now the Holyrood gas turbine is a very expensive unit to run, so that cost is a new cost that wasn't there back in 2007 and it's been required to run fairly frequently. So, initially when there was a discussion of the energy supply cost variances, a lot of discussion around we purchase from Nalcor at four cents, but if water levels go up or down, then we've got to replace it with Holyrood fuel. So you're dealing with the four cents versus the 15 cents. So which is similar to the way the rate stabilization plan works.

Now it's been commented that -- I think

by Mr. Patrick Bowman, that we should have just put it in the RSP and we actually -- it was talked about, but the RSP is so complicated now, we thought it would be easier to just set it aside as its own item for now and when we review the supply cost mechanisms going forward, we'd look at some aggregation of where supply cost variances should be. But so for purposes of transparency in looking at what's new proposed for the Board, it was presented as a -- these were all presented as single items so that the Board could look at them in that light, but the energy supply cost variance on the Island Interconnected system, the combustion turbine cost variances, which may be, you know, 30 cents a kilowatt hour when you're running that, it's not so much an issue of the price variability of No. 2 fuel, but the volume of running No. 2 fuel -- using No. 2 fuel that can cause a big impact on Hydro's financials.

So, when it was initially discussed at Hydro, we were talking about the difference between the four cents of purchases from Nalcor versus the 15 cents, and now it's

transitioned into both a combination of shifting the levels, shifting costs that are also the Holyrood combustion turbine as well as the purchases from Nalcor. And it's not just about risk for Hydro with respect to purchases from Nalcor. If water levels are up and we get more purchases from Nalcor, then there's fuel savings. So similar to the hydraulic component of the RSP, those savings would be passed back to customers. So it's more consistent with a rate stabilization aspect, although it's been set aside in a separate account, than just strictly a risk of Hydro.

Now there's one issue with regard to that's often missed with respect to Hydro is that load growth on the system for Hydro is all through the RSP and the mechanics and way it works, it's all served at Holyrood. So the cost to Holyrood on our forecast is 15 cents a kilowatt hour. So, the revenue from the Industrial Customers for the increased sales, say in our forecast, is about five cents a kilowatt hour. So for every kilowatt hour of growth in load, there's a ten cent loss. So

the rate stabilization, and that's the load variation component of the rate stabilization, provides a recovery of that cost.

(11:00 a.m.)

And that effectively, and with Newfoundland Power as well, the load growth is -- all load growth on the system, all those costs of providing the load growth and all the revenues that are incoming for energy load growth, all goes to the RSP. Hydro makes no earnings on sales growth. It's only if demand increases and that's sometimes it happens year over year. Hydro's industrial customers are typically stable load. They're in a current change because of the phase-in of the new customers, but it's typically stable. So you don't have growth in industrial customer demand. Newfoundland Power's demand creeps up. Some years it goes up; some years it doesn't. So, Hydro is almost effectively decoupled from getting earnings growth from sales increases from customers. Puts a big challenge on Hydro with regard to meeting cost increases. So you've got to provide your capital investment.

So that's why when Hydro looks at the years going forward that you've got big challenges to meet cost increases, even just of capital investment, because you don't have sales growth earnings. I mean, most utilities -- I know in the US, marginal costs are below the embedded costs, so if there's sales growth, they're actually making money on the sales growth which allows them to stay out -- they could stay out longer.

In Newfoundland Power's circumstance, they've got a deferral account which effectively protects their earnings on sales growth that it stabilizes the cost of purchases from Hydro, so that they manage to keep their two and a half to three cents a kilowatt hour as sales increases. But for Hydro, Hydro doesn't have that. So it's almost more important for Hydro to get deferral accounts because it allows us to recover costs beyond your control but you still got the challenges of meeting your normal increases in operating costs.

JOHNSON, Q.C.:

Q. We're at past 11.

CHAIRMAN:

Q. I think we need a break, sir.

JOHNSON, Q.C.:

Q. Thank you.

MR. FAGAN:

A. Yeah, I agree.

CHAIRMAN:

Q. Thank you very much.

(BREAK - 11:03 a.m.)

(RESUME - 11:38 a.m.)

CHAIRMAN:

Q. So I understand before we proceed, there is a revision to an undertaking.

MS. PENNELL:

Q. Yes, we had to revise Table 4 in Undertaking 44 which we filed yesterday because the test year load normalization scenario presented by the Consumer Advocate. And Undertaking 35 has also been filed, our winter readiness report that we filed with the Board last week.

CHAIRMAN:

Q. Okay. So Mr. Johnson, I do believe, sir, we are back to you.

JOHNSON, Q.C.:

Q. Thank you, Mr. Chairman. Just a slight

revisitation on O&M for a second or a few minutes, Mr. Fagan. I guess, you know, the application that we have in front of us that we've been dealing with is that Hydro has been proposing specifically assigned charges as set out in its rate schedule at page six of 46. So, I guess, Mr. Fagan, we don't know exactly now what methodology Hydro is now proposing and the details of how it will be implementing, the customer impacts and those type of things. We had an RFI reply. We had a bit of evidence from Greneman on the stand, Mr. Greneman on the stand. Like is Hydro going to be amending the application to set out these details, the customer impacts, how this is supposed to be implemented, you know, the basis for it?

MR. FAGAN:

A. Well, Vale-083 presents the shift, I will call it, from the change in the approach in the application to the recommendation of the methodology of Mr. Dean. So the specifically assigned charges would be what's reflected in -- for O&M would be what's reflected in that particular document. With regard to the

shifting of the cost to common, we'd have to run that through the cost of service study to determine the impact on Newfoundland Power and the Industrial Customers, but effectively would be a -- I think we could probably present a table which would illustrate the effects of that. But it would come out in the final cost of service study with regard to how -- the final numbers on it, but we can provide the impacts on Newfoundland Power and the end result if we followed that analysis with regard to specifically assigned charges and how the other rates would change to reflect it.

JOHNSON, Q.C.:

Q. Okay. And so how are we going to go about checking the results that come out of Vale-083 to ensure that they're sound and reasonable for immediate implementation in this GRA?

MR. FAGAN:

A. When we file our compliance filing with the Board, the Board usually has Grant Thornton review our compliance filing to ensure it meets the methodology approved by the Board. So, I mean, that could be part of it.

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JOHNSON, Q.C.:
Q. I mean, Grant -
MR. FAGAN:
A. Or we could circulate it to -- and it would be circulated to other parties. We could circulate it to other parties for their feedback on it. When we file a compliance application, other parties have an opportunity to review as well.
JOHNSON, Q.C.:
Q. So that's the method by which we're going to test the soundness and reasonableness of the numbers that come out of Vale-083?
MR. FAGAN:
A. No, I don't know if I'd quite say it that way. I think the principle on which you'd determine O&M costs can be established without having the full numbers with regard to the rates for every customer coming out of a compliance filing. So, if the Board believes it's reasonable to restate the original cost in the cost of service for purposes of determining specifically assigned charges based on real dollars and calculate the specifically assigned charges based on real dollars, we'll

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make changes to comply with the order of the Board and we'll be presenting results to show that for review by all parties and Grant Thornton upon compliance filing. So I think the Board can make a principle decision without knowing how exactly that $200,000 shift or two or three hundred thousand dollar shift will work out in all the numbers on everybody else's bills.
JOHNSON, Q.C.:
Q. Okay. And I guess you're saying that the Board will have enough evidence before it in this proceeding to say that like the 150, 000 or 149,000 that would get specifically assigned to Vale that that is a reasonable number and that's borne out by, you know, what it should have cost to maintain assets of this type?
MR. FAGAN:
A. Well, I think it's a principle decision that you're looking at. You're looking at your operating and maintenance costs as a percentage of your investment in capital and you're looking at it on a consistent basis in real dollars. So using that to come up with a

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percentage for determining specifically assigned O&M is probably reasonable, at least initially, until we do a full review of the specifically assigned charges methodology in the cost of service review.
JOHNSON, Q.C.:
Q. Presumably we'll have a much better handle on the reasonableness after the full review that you're speaking of in the cost of service study, right?
MR. FAGAN:
A. We would certainly review what we came up with to see if there's any weaknesses with it or anything, but based on a principle basis, I wouldn't see that you would conclude different, but I think it would be certainly a more comprehensive review probably of what's done in other jurisdictions would probably be part of the cost of service methodology review.
JOHNSON, Q.C.:
Q. Yeah.
MR. FAGAN:
A. So that would be -- that would certainly give more support to a longer term approach.

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JOHNSON, Q.C.:
Q. Yeah, and that review of which you're speaking, that may well in fact identify a weakness that we're not seeing presently on the record before the Board?
MR. FAGAN:
A. That's possible.
JOHNSON, Q.C.:
Q. Yeah, that's right, okay. Now in terms of -
MR. FAGAN:
A. But should make the -- sorry.
JOHNSON, Q.C.:
Q. In terms of that indexing idea, will that be an annual exercise? Will the specifically assigned charge be changing from year to year or how do you see that happening?
MR. FAGAN:
A. Same as it has been in the past. Specifically assigned charge is established in the test year and it would remain the same.
JOHNSON, Q.C.:
Q. Okay.
MR. FAGAN:
A. Until the next test year.
JOHNSON, Q.C.:

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Q. Okay. Now, Mr. Fagan, we've already discussed in this hearing the fact or the phenomenon, I suppose, of the fact that the Island Industrial Customer class load is going to increase dramatically in 2016 and 2017 over levels included in the 2015 test year cost of service study, correct?

MR. FAGAN:

A. That's correct, yes.

JOHNSON, Q.C.:

Q. And you know, and would it be fair -- I've characterized it as a dramatic increase, and would that be -- that wouldn't be an overstatement, would it?

MR. FAGAN:

A. No, it's not. It's a dramatic increase in the Industrial Customer load.

JOHNSON, Q.C.:

Q. Yeah. Now and of course, that's being driven by the continued evolution of operations at Vale as it moves to full production?

MR. FAGAN:

A. Yeah. I just want to clarify, it's a forecast dramatic increase. So unless the numbers change, it's certainly a dramatic increase and

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as a result of Vale moving to full production.

JOHNSON, Q.C.:

Q. These numbers represent the considered view of these Industrial Customers as to what their operations are going to be even in a few months time, because we're late in -- fairly late in 2015 now.

MR. FAGAN:

A. Yes, it's just the forecast is based on the GRA forecast that was filed in November 2014. So, the numbers are not updated. So I'm not sure if it's the best estimate of what's there for 2016 and '17 right now.

JOHNSON, Q.C.:

Q. Okay. But you haven't been advised by these customers that these forecasts are no longer what they're standing by for those years?

MR. FAGAN:

A. I've got no better information with respect to a forecast. I think the experience so far this year for Vale may be that they're maybe 12 megawatts less than what was anticipated. So they may be about six months behind of what we would have planned. But I think when you determine a test year, you come up with, you

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know, your best estimate of what your forecast is. So I don't know if that necessarily would change things.

JOHNSON, Q.C.:

Q. Okay. Now Mr. Fagan, I take it that you would have no trouble agreeing with me that the loads included in the 2015 test year cost of service are not reflective of the loads during the period that rates are expected to be in effect, right?

MR. FAGAN:

A. Well, if you want to say loads for Industrial Customers, but loads on the system are not that different. I mean, you've got -- in 2017, you'd have a higher proportion that's industrial load.

JOHNSON, Q.C.:

Q. Yeah.

MR. FAGAN:

A. But the total loads are -- from a system perspective, I don't know if they're -- it's that big a difference.

JOHNSON, Q.C.:

Q. Okay. But you'll agree with me that the Industrial Customer loads then in the 2015

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test year cost of service are not reflective of the loads during the period that these rates are expected to be in effect?

MR. FAGAN:

A. Yes, and that's -- when we were preparing the application, we recognized the load growth of the Industrial Customers, so that's why we reviewed it, and I think we brought up IC-NLH-140, first revision.

(11:45 a.m.)

JOHNSON, Q.C.:

Q. Yeah, but before -- okay.

MR. FAGAN:

A. Just it's -

JOHNSON, Q.C.:

Q. I'll let you go, but -

MR. FAGAN:

A. No, it's only a short response.

JOHNSON, Q.C.:

Q. Okay.

MR. FAGAN:

A. So with respect to the second paragraph, when we look -- the concern when you've got a customer, large customer coming on is you don't want -- you don't want the rates in the

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test year to be somewhat of an anomaly. So when we looked at the coincident peak load factor for 2015 test year of approximately 97 percent and said, okay, well that's reflective of a high load factor Island Industrial customer, so presenting using Vale and Praxair's load in 2017 is not distorting the results. We viewed it from a cost of service perspective in determining rate design. That doesn't mean you're recovering all the costs associated with serving Vale and Praxair as they go going forward, but the actual unit rate you're deriving for the customers should be fairly stable. That was our view.

JOHNSON, Q.C.:

Q. Okay. So in connection with this topic, let me bring you to Undertaking No. 41, in particular Table 1 of that. Now this table is looking at the impact of normalization of the test year forecast on the Island Industrial Customer test year demand charge, according to the heading underneath Table 1 or where it says Table 1. Now, and we see, Mr. Fagan, that the Island Industrial Customer allocated demand costs increase as you go across from

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2015 to 2016 to 2017, right, from 8.9 to 10 million to 11.6 million respectively. You see that?

MR. FAGAN:

A. That's -- if we redid cost of service to reflect those load forecasts, I think that just on the demand cost alone because we were looking at demand revenue requirement and reallocating it based on the load growth, yes, the cost would increase, but the unit rate for the customers wouldn't change a lot.

JOHNSON, Q.C.:

Q. Yes, so what we see there is the IC demand cost is 8.38, $8.38 in 2015, 2016 it's 8. 33 and 2017 is 8.38, but you average them all out and you get to 8.38, right?

MR. FAGAN:

A. Yeah.

JOHNSON, Q.C.:

Q. Okay. And by the way, if you -- the numbers, I think you'll confirm, for Newfoundland Power's unit demand cost are for 2015, $10.18? Is that right, based upon the -

MR. FAGAN:

A. I think that's in a table further on in the

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response.

JOHNSON, Q.C.:

Q. Yes. So if you want to go to that table, Attachment 1.

MR. FAGAN:

A. Sure.

JOHNSON, Q.C.:

Q. Line 14.

MR. FAGAN:

A. Yes, you're correct.

JOHNSON, Q.C.:

Q. Right. So, for Newfoundland Power, it would be 10.18 in the test year. In 2016, it drops to 9.96 and then drops in 2017 to 9.72 and averages out to 9.95 as a three-year average.

MR. FAGAN:

A. Sure.

JOHNSON, Q.C.:

Q. Okay. Now, and I guess we can observe there that the ICs have unit demand costs that are materially lower than what Newfoundland Power would have in those years. Would that be correct?

MR. FAGAN:

A. Yes, that would be really consistent with past

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practice, that the Industrial Customers have higher load factor and a lower coincidence with system peak. So their unit demand cost is generally lower than Newfoundland Power's unit demand cost.

JOHNSON, Q.C.:

Q. Yes, and while the Island Industrial Customer load is growing in 2016 and again in 2017, you would in fact expect to see Newfoundland Power's unit demand costs edging downward. Would that be the expectation?

MR. FAGAN:

A. Yes, in this particular scenario where we're keeping the total demand cost the same and divide by the increased loads for both parties, yes, that would be the normal result because the Industrial's load is growing faster than Newfoundland Power's from a percentage basis.

JOHNSON, Q.C.:

Q. Yeah, so unlike the scenario that was put forward in Undertaking No. 44 yesterday, we're not talking about a normalized unit cost for the Industrial Customers of anywhere near $10.95 a kilowatt?

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MR. FAGAN:
A. No, that's correct.
JOHNSON, Q.C.:
Q. That's correct.
MR. FAGAN:
A. Now the only thing is there's a -- one difference between Newfoundland Power and the Island Industrial Customers is that the unit cost becomes a demand charge, okay, and for Newfoundland Power, their demand charge, current one is four dollars a kilowatt, and I think in the settlement agreement we've put forward to the Board, it's $4.75 a kilowatt. So, from a demand charge perspective, the Newfoundland Power demand charge is not derived strictly from the unit cost variance. So, from a revenue forecast perspective, but it wouldn't actually change the rate design for Newfoundland Power.
JOHNSON, Q.C.:
Q. It wouldn't change the rate design, no, okay.
MR. FAGAN:
A. Right.
JOHNSON, Q.C.:
Q. But these would represent the actual unit demand cost, yeah, okay.

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MR. FAGAN:
A. Based on the assumptions we've made with regard to maintaining the demand cost the same for each year, yes.
JOHNSON, Q.C.:
Q. Okay. Now if you look under the table there, there's text on Table 1 of Undertaking No. 41 that says "Table 1 shows that while the allocated demand revenue requirement to IIC increases materially using the 2016 and 2017 forecast reflecting the higher demand requirements for the IIC, there is minimal change in the unit demand cost as a result of the higher demand billing units used to compute the unit cost." But just to focus here on the first part of that statement, I take it that there's no disagreement that what we're talking about is a material difference in relation to the allocated demand revenue requirement that we're seeing between test year 2015 and taking an average of 2015 to 2017?
MR. FAGAN:
A. That's right.

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JOHNSON, Q.C.:
Q. Hydro refers to that 1.3 million dollar difference as being quite material?
MR. FAGAN:
A. Yes, it is. The only thing is though it just also, in my view, would show that the demand charge proposed would reasonably recover the costs over those years, so as Vale's load ramped up, the charge they would be paying in those years would reasonably recover the demand costs effectively assigned to them.
JOHNSON, Q.C.:
Q. But by the same -
MR. FAGAN:
A. One thing, just for clarity, the demand costs don't -- if load grows on the system, goes up and down throughout the year and year over year between test years, demand costs don't necessarily change because of a single shift of one kilowatt of demand. You've got your fixed capacity on your system. The energy is if the load grows from the new customers coming on, it's driving variable costs on the system. So, the big issue with regard to the -- to me, from the Industrial Customers load is make sure that we're recovering the variable costs associated with the load growth and eventually when I go to Undertaking 44 and I can demonstrate how that would work, but the -- so our view is that the unit cost of energy that we proposed, in combination with the operation of the RSP, will recover the full energy costs from the load growth and within the -- because the load variation component that's proposed to be done on an energy allocation basis, the sharing of the additional load cost because of the ramp up of Vale and Praxair is done in the same way as it would be in the cost of service study because it would be based on the percentage of energy for the Industrial Customers versus the percentage of energy for Newfoundland Power. So, all the real system costs, additional system costs because of Vale and Praxair coming on the system are being shared consistent with the cost of service approach because they're really driving the energy costs.
JOHNSON, Q.C.:
Q. But the load variation component takes over

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after the test year anyway, right, I mean, in terms of we're putting certain values and assumptions in the test year and after that, you know, the RSP does its work, right? I mean, that's just normal.

MR. FAGAN:

A. That's right, but the key to the test year is -- and I think it was probably demonstrated in the original filing of the 2013 test year, that the demand charge for -- proposed demand charge for Industrial Customers I believe may have been slightly higher than the demand charge proposed for Newfoundland Power or certainly it was in the ballpark. I don't remember the exact number, but it may have been a few cents apart. And that wouldn't have been normal, based on the circumstances or the demands, forecast demands of Industrial Customers and their coincidence with system peaks.

As I mentioned in my opening statement, every test year I've ever seen, the demand charges for -- or unit demand costs for Island Industrial Customers is always slightly below the unit demand cost for Newfoundland Power

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because Newfoundland Power has a lower load factor, they're on peak more. So when you look at that 2013 forecast, test year forecast which was provided in IC-140 original, it would set off alarm bells for me. And so that's why when the Industrial Customers questioned in IC-140 about doing a revision to reflect a normalized demand within the year, making an adjustment for assuming Vale and Praxair would be a high load factor in that year, even though it would have been a very small customer, it would have been estimated to be four megawatts, took the distortion away from computing the unit demand cost for purposes of setting a rate and so when we looked at Vale and Praxair and their load going forward, the key is when you're putting them in a test year is that you don't distort the unit cost.

As their load grows, they're going to pay for their cost because as their load grows, they're going to pay the unit demand costs and they're going to pay their energy costs through either both the firm energy charge that's approved and the RSP, and that RSP

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sharing between Newfoundland Power and Industrial Customers is consistent with the sharing it would incur in the cost of service study anyway, so I think it -- I think that what's proposed with regard to the 8.38 demand charge is a reasonable one going forward that they're paying -- Vale and Praxair are paying the same demand charge as other customers would almost without Vale and Praxair being included because they're not distorting it because they're a similar load factor than the others.

So, I think the test year works from that perspective, that it doesn't result in a distorted demand charge and the mechanism with regard to the RSP load variation doesn't result in any distortion to the recovery of incremental energy costs because of load growth on the system.

JOHNSON, Q.C.:

Q. Well, like if you look at Table 1, it's still there in front of us, and we picture the 2015 test year column that Newfoundland Power's unit demand cost is $10.18 and then it would fall off to 9.96, 9.72 and average 9.95,

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Newfoundland Power is being put in a demand cost which is 10.18 and there's no decreasing along the way. I guess my difficulty is, you know, what's happening to the spread between the 8.9 million and the 10.2 million. I mean, someone's picking that up. It's Newfoundland Power is picking it up, right?

MR. FAGAN:

A. No, I wouldn't agree with that. Newfoundland Power's demand charge will be -- assuming the Board would approve it, $4.75 per kilowatt. So Newfoundland Power will be paying that demand charge going forward. The energy costs which would be flowing through through the RSP, Newfoundland Power will be paying approximately 90 percent of the Industrial Customer energy costs. So, that's what would happen within the cost of service. The only, okay, intricacy with respect to it, the difference, is that Newfoundland Power's tail block energy rate is set at the test year price of fuel, at least historically, and I think we've got a settlement agreement to deal with that on a go-forward basis. So their load growth going forward, which is, you know,

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fairly small each year, they'll pay that portion of it. But they're sharing in the portion of the load growth for Industrial Customers through the RSP. So their demand -- Newfoundland Power's demand charge is not derived from -- on a unit cost basis the same way the Industrial customers is. So I don't think the comparison of the cost, the unit cost for Newfoundland Power is necessarily has rate implications.

JOHNSON, Q.C.:

Q. It mightn't have rate implications, but it has cost implication to Newfoundland Power, doesn't it?

MR. FAGAN:

A. When you say "cost implications", I think the revenue requirement allocated to Newfoundland Power and industrial customers within the test year is reasonable based on the forecast because we've got the test year cost there for both industrial and Newfoundland Power, and we've complied with the cost of service methodology approved by the Board. So where we're at now is looking at more of a rate design issue for industrial customers, and you

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don't want to distort the rate design for the industrial customers because there's a ramp up of load going to happen in the next couple of years. What happens actually is the additional demand charges for industrial customers, and in this particular case it shows an increase in demand charges of about 1.1 million dollars between '15 and '16, and an additional 1.6 million dollars between '16 and '17. That's additional revenues to Hydro to offset other cost increases, because I mentioned demand costs don't necessarily go up and down because of load changes, so this additional revenue to Hydro to offset other cost increases, capital investment, inflationary increases, because of demand growth. That's not usually the norm with regard to industrial customers because normally their load is stable, so they've set their firm demands, but because it's in a low growth position for Vale, there's additional revenues coming into Hydro because of that low growth to offset other costs in those years. It's not necessarily distorting what Newfoundland Power is required to pay in the

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test year.

JOHNSON, Q.C.:

Q. Well, if I look to that statement below Table 1 that says that the allocated demand revenue requirement to the island industrial customer increases materially using the 2016 and 2017 forecast, and given that, you know, as we've agreed, the cost of service analysis should reflect fair and reasonable estimation of the cost responsibility between customer classes for the period in which the study is being applied, I would ask are you saying that Hydro doesn't see any difficulty with this and is not proposing any adjustment for the cost of service study to -

MR. FAGAN:

A. I think your interpretation of the change in costs may be leading to a conclusion that I don't agree with. Column B is basically saying if you had the same demand cost on the system in 2016 as you got for 2015, you'd come up with a different demand revenue requirement for industrial customers, but you can't really bring that cost back to the 2015 and derive a rate, and I think that's what's shown in

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Undertaking 44. If you try and bring the cost back, you end up with too high a rate. So as long as - for instance, let's say Vale and Praxair weren't going to come on until 2016, you could come up with a reasonable rate for the industrial customers without Vale and Praxair being reflected in the test year as long as - and it would probably be reasonable for Vale and Praxair as well, as long as their load factor is comparable to a typical industrial customer. What happens is that when they come on, they pay the average cost that was reflected in the test year, and it recovers the cost from them at that time. It would be more of a windfall for Hydro to recover some other costs because Hydro would have demand charges - additional demand charges that wouldn't be reflected in the test year, so that would provide more security for Hydro in '16, but it doesn't - as long as the customers are similar load factor and similar coincident to peak as the other industrials, it doesn't result in the demand charge being incorrect. So if you try and bring it back, you'll distort the demand charges and

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potentially the energy charges as well. As long as the unit cost is comparable year over year, just in this particular circumstances shows that when Vale and Praxair are on fully, the demand charge wouldn't change very much, so they're paying their way. It works for both the industrial customers, for Vale, and Praxair, being partly phased in versus being fully phased in, the rate is still reasonable. That's my interpretation of it.

JOHNSON, Q.C.:

Q. But if we tried to incorporate or reflect in the 2015 test year the fact that they will be ramping up - if we tried to reflect that, wouldn't that be of benefit to Newfoundland Power customers?

MR. FAGAN:

A. I think the rate stabilization plan works to protect customers in that manner.

JOHNSON, Q.C.:

Q. But how about on demand?

MR. FAGAN:

A. To me, as long as the load factors are comparable and as long as they're billed in a unit cost basis, which Newfoundland Power

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isn't, and industrial customers are, you come up with a similar unit cost rate so it doesn't disadvantage either Newfoundland Power's customers because of them not being fully ramped up in the 2015 test year. You can't bring back their demands now and bring their costs in, in advance of having the loads to recover the cost, you'll distort the rates.

JOHNSON, Q.C.:

Q. Well, how then do we - this principle that everybody seems to agree upon about the cost of the service analysis reflecting fair and reasonable estimation of the cost responsibility between classes for the period in which the study is being applied -

MR. FAGAN:

A. That's achieved.

JOHNSON, Q.C.:

Q. You feel that that's achieved by not making any adjustment at all to the fact that there's going to be a dramatic increase in '16 and '17 to industrial customer load?

MR. FAGAN:

A. As long as the rates that are approved are reasonable for Vale and Praxair, consistent

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with typical industrial customer, there's no - and within the rate stabilization plan mechanism to recover the incremental cost which shares that, I'll call it, on the cost of service basis of fuel, so sharing it based on energy ratios consistent with the cost of service, then I think it works well with respect to - this is one of the important aspects. The load variation component of the RSP is important especially when you've got a ramp up of a new industrial customer coming on, so you don't end up with an unfair rate for customers or potentially lack of cost recovery for Hydro.

JOHNSON, Q.C.:

Q. If you go to Table 2, again if we took an average of the industrial customer energy requirement over '15 and '16, and '17, you're talking about a very material sum of money in the difference, aren't you, from 32 million to 38 million?

MR. FAGAN:

A. Table 2 doesn't show the - I mentioned that capacity is more of a fixed cost between test years unless there's all of a sudden a big

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ramp up of additional capacity on the system, but energy is the immediate impact of a change in cost. If we want to discuss the impact, I don't think this necessarily demonstrates it. I'd rather if we could go to Undertaking 44 for a minute, and go to Table 4. There's a lot of numbers in this table, so I'll try and go slow. If we look at line 4, we see the industrial load going from 621 gigawatt hours to 873. So you've got 250 gigawatt hours increase. That's at Holyrood fuel which is about 15 cents a kilowatt hour. So that's around 37 million dollars of additional fuel cost incurred to provide that load. Now if we look at line 1, which is the proposed unit rate of 5.151 cents per kilowatt hour, and if we compare the 2017 revenues on the unit rate to the 2015 revenues on the unit rate, we've got 45 million versus 32. So we've got an additional 13 million recovered from the industrial customers on 5.1 cents per kilowatt hour rate. Now so that leaves us with about 24/25 million dollars extra cost. If we move down to the RSP impact, footnote 1, and the first shaded number in the last column, the

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25.7 million dollars, that's the additional fuel cost from industrial customers load that's not recovered from the firm energy charge. So in cost of service study, we got energy costs and fuel costs that we share based on their proportion of energy. If we look at - we've got an IC allocation and an NP allocation down a few rows. There's a 3 million dollar and a 27 million dollars to Newfoundland Power. So there was a 25. 8 million dollars load variation for industrial customers. Newfoundland Power's load also grew relative to the test year, so we've got about 5 million dollars there, 4.997 million. So the combined effect of the load growth beyond the test year is 30.7 million. The industrial customers would pay 10 percent of that, and Newfoundland Power's customers would pay 90 percent of that. Now this is based on Hydro's proposed rates in the amended application. If those fuel costs were in the 2015 test year conceptually, and Vale and Praxair were on the system fully implemented, then industrial customers would pay approximately 10 percent and Newfoundland

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Power's customers would pay approximately 90 percent. So you still got this sharing going on - well, actually this 10 and 90 will change over time because as the load ramps up in the rate stabilization plan, the percentage of the load as a percentage of the last most recent 12 months, so the 10 percent maybe in the 2015 test year, it may be 11 percent in 2017. So you'd end up with the industrial customers still paying their share of the additional fuel cost that's incurred as a result of the load ramp up. So from a variable cost perspective, of all the real additional cost on the system because of the industrial customers coming on, the proposed rate in combination with the RSP operation does provide a fair recovery of those costs of the additional industrial load.

(12:15 p.m.)

JOHNSON, Q.C.:

Q. Mr. Fagan, what would it require for you to believe that there would have to be some adjustment made to the 2015 test year? Like, obviously you're indicating that the 20 percent increase in island industrial customer

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load in 2016 over 2015 levels is not sufficient, the 40 percent reflected in 2017 over 2015 levels does not cause any need for adjustment, so what sort of magnitude of change would we need to see for Hydro to make or propose an adjustment to the 2015 test year?

MR. FAGAN:

A. There would have to be a change in loads and a change in demands, so that the load factor reflected in the test year is not really reflective of the long term load factor for the industrial customers, and if there was a big shift in load factor, then the demand charge and coincident factor kind of peak, the demand charge coming out of the test year may be flawed, but we haven't - looking at that Undertaking 41, we see that the costs are fairly stable. I mean, quite often in Newfoundland Power's case, when I was there before, you've got new customers coming on the system all the time, and sometimes fairly large. As long as a new customer coming on in the class doesn't change the load shape and the unit cost, the rates can still be

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reasonable even though there's a large increase in the load. So it's more about making sure the rate is reasonable and the load factor for the additional customers is still close to the load factor and the coincident for the other customers that are in the group, so you don't end up with a distortion in the rate to the customers. That's what I'd look at. That's why in that updated response to IC-NLH-40, we looked at the coincident peak load factor for the 2015 test year, which indicated 97 percent load factor, and said, all right, so 2015 shouldn't be a distortion because we looked at that load factor versus the forecast years and said, that should be okay, we're going to come up with a reasonable unit rate that'll apply to all the customers over the period of 2015 to 2017.

JOHNSON, Q.C.:

Q. And you adjusted the load factor to look like a year that might happen some time in the future?

MR. FAGAN:

A. Well, that was in the original IC-140. I was thinking about in the IC-140 revision. The original IC-140 was an example of when you'd want to make an adjustment because the average cost for industrials actually exceeded the average demand unit cost for Newfoundland Power, which wouldn't be expected for a high load factor group with a lower coincident type of peak. So that set off alarm bells for me with regard to the 2013 test year, that it would have been appropriate to make some adjustments, but for the 2015 test year, the relative difference in the unit demand cost for industrial customers and the unit demand cost for Newfoundland Power appeared to be reasonable.

JOHNSON, Q.C.:

Q. But Undertaking 41 did purport to be a normalization exercise, didn't it?

MR. FAGAN:

A. It was a normalization exercise with respect to estimating what the unit demand costs would be if we looked forward beyond 2016, and effectively we're redoing 2016, but this would have assumed in 2016 that you would have had those units to bill the customers in 2016. So

when you're coming up with the 833 in 2016, you're matching the revenue requirement with the units that the customer is anticipating to use in 2016. The difficulty comes if you start trying to bring those units back into a 2015 test year, that you distort the percentage allocations, and you come up with rates that don't really reflect the cost of serving.

JOHNSON, Q.C.:

Q. Thank you, Mr. Fagan. Those are the questions.

CHAIRMAN:

Q. I think Mr. Coxworthy, over to you.

MR. COXWORTHY:

Q. Yes, thank you, Mr. Chair. There was an information document that I was seeking to have circulated.

MS. GLYNN:

Q. We'll enter that as Information 11.

MR. KEVIN FAGAN - CROSS-EXAMINATION BY MR. PAUL COXWORTHY:

MR. COXWORTHY:

Q. Thank you. Mr. Fagan, you have Information 11 there in front of you?

MR. FAGAN:

A. Yeah, I'm good.

MR. COXWORTHY:

Q. I just want to make some comments, in fact, corrections or at least clarifications. The table is referred to as being 2013 from IC-NLH-002 revision 1, but in fact the information in the table comes from the unrevised version, which is over 800 pages of cost of service studies going all the way back to 2007.

MR. FAGAN:

A. I appreciate the single page.

MR. COXWORTHY:

Q. Well, I thought perhaps everyone would rather than going through 800 pages of cost of service studies. I don't know whether you had the opportunity to review these figures or whether you're familiar enough with these figures to be able to confirm that they are an accurate representation of the relationships between demand and between IC, and Newfoundland Power, in those respective years and also in relation to energy?

MR. FAGAN:

A. I've reviewed them from a high level and some look like anomalies, so I did a bit of checking on them. To be clear, we've got a mixture here of test year cost of service studies and actual cost of service studies, and what happens with actual cost of service studies is in some cases it may be really a cold year, and Newfoundland Power may be driving the peak, and so you'd end up with the average cost and the demand basis for Newfoundland Power may be higher in that year. There's another year here in 2010, you'll see the average demand cost for industrial customers is $2.78 per kilowatt. I believe in that year there may have been a fire at North Atlantic Petroleum, so they weren't in service at the time of peak, or they were maybe only partially in service, so the demand cost allocated to them was materially lower relative to their billing units. So when you're dealing with actual cost of service study year over year, they're not used for rate setting so you do have a fair bit of variability in the numbers, but with that caveat, yeah, the numbers, they don't really

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look unreasonable from what I would expect.

MR. COXWORTHY:

Q. And I haven't gone back and reviewed all those cost of service studies either. Mr. Patrick Bowman has done that, but I have looked at the 2013, and for the interest of the record, this information can be derived from Schedule 1.3, page 1 of the 2013 actual cost of service study, and I presume a similar schedule would apply for the other cost of service studies as well.

MR. FAGAN:

A. Yes, I expect so.

MR. COXWORTHY:

Q. So in terms of the relationship, do they consistently show with respect to demand that IC demand is - whether it's test year or actual cost of service study, that industrial customer demand rates are consistently lower than Newfoundland Power's, somewhat lower?

MR. FAGAN:

A. Yes, that's a fair comment.

MR. COXWORTHY:

Q. And you've spoken to the reason for this, and you've spoken to the fact that the industrial

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customer class, as a class, has presumably over this whole period shown factors of being at a high load factor, but a relatively lower coincident peak, as compared to Newfoundland Power which has lower load factor, but higher peak?

MR. FAGAN:

A. Yes, from the Board's perspective, higher load factor - customer with the higher load factor, we ended up with less demand cost. We classify a lot of our costs on load factor, and so the higher load factor customers, they've got less demand costs allocated to them than lower load factor customers, and so Newfoundland Power is a lower load factor customer, they're more coincident with peak because electric heat in our system often drives the system peak, so the allocated demand cost on a unit basis would normally be higher for Newfoundland Power than it would be for the industrial customers.

MR. COXWORTHY:

Q. This, of course, only takes us to 2013, Information 11. When one looks at 2014, 2015 forecast, and we've got some actual numbers,

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2016, 2017, will industrial customer class continue to be high load, relatively lower coincident peak, will the continue that pattern?

MR. FAGAN:

A. Based on the forecast, yes.

MR. COXWORTHY:

Q. Based on the forecast?

MR. FAGAN:

A. Based on the forecast, there will be no change.

MR. COXWORTHY:

Q. So even with the ramp up with Vale, that doesn't change that aspect of the demand relationship as between Newfoundland Power -

MR. FAGAN:

A. I spoke to our forecaster about the coincident, and Newfoundland Power's peak is assumed to be on average 99 percent coincident with system peak. The industrial customers on average is more around 88 percent. So we have no reason to think that will change.

MR. COXWORTHY:

Q. Looking at Information 11, and if we could move on to the energy comparison, the energy

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rate for the industrial customers, whether it's test years cost of service, actual cost of service, and those for Newfoundland Power for energy, they stay relatively close to each other over time?

MR. FAGAN:

A. That's correct.

MR. COXWORTHY:

Q. And I think you've already testified that that's as you would expect?

MR. FAGAN:

A. Yes, you wouldn't anticipate any reason that the energy costs would be different, materially different.

MR. COXWORTHY:

Q. Can you explain to a layperson like me why that's different from demand, why doesn't the unit cost for energy for industrial customers, why is that not different than for Newfoundland Power?

MR. FAGAN:

A. Well, a lot of the energy cost are fuel, right, so you're just taking it, dividing it by the amount of energy, so it's no different on a unit basis for industrial customers

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versus Newfoundland Power's customers, so the unit cost of fuel at Holyrood, say, 15 cents a kilowatt hour, well, it's 15 cents a kilowatt hour to provide the energy to an industrial customer, it's 15 cents a kilowatt hour to provide it to Newfoundland Power's customer.

MR. COXWORTHY:

Q. So there's no reason for it to cost any different depending on what customer we're talking about.

MR. FAGAN:

A. Not material, no.

MR. COXWORTHY:

Q. What class of customer?

MR. FAGAN:

A. You certainly wouldn't anticipate any material difference.

MR. COXWORTHY:

Q. And with that I'd like you to turn to undertaking 44. And if we can turn to the second page of undertaking 44 which comments on Table 2, I believe, which appears on the first page. If we look at the first paragraph of the second page. We might need to go back to Table 2, as we discuss this paragraph. But

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the first paragraph on the first page of undertaking 44 says that from an energy cost perspective, the average energy unit cost is generally approximately the same for Newfoundland Power and Industrial Customers. That's what we were just talking about, is shown at Information 11.

MR. FAGAN:

A. That's correct.

MR. COXWORTHY:

Q. You then comment on Table 2, your Table 2 or the Table 2 that was produced as part of this undertaking response, shows that under the normalized test year the proposed energy charge would be approximately 30 percent higher for the industrial customers. Is that a reasonable result?

MR. FAGAN:

A. No.

MR. COXWORTHY:

Q. And why not?

MR. FAGAN:

A. Well it doesn't reflect the cost of serving them in the test year. The cost of serving Newfoundland Power in the test year on an

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energy basis and industrial customers on an energy basis is approximately the same. So if one saw that coming out of a cost of service, you'd wonder what you've done wrong, so we're putting costs to be allocated to industrial customers in the test year that is not reflective of their load in the test year, and that's driving it up.

MR. COXWORTHY:

Q. And won't that also then be true for 2016 and 2017?

MR. FAGAN:

A. If you brought those numbers back to the 2015 test year, you'd have the same effect. So if you brought back--if you normalize, undertaking 44 is normalized based on a 2017 forecast. If you brought 2016 forecast back, you'd have the same effect. The magnitude may be somewhat different, but you'd have the same effect.

MR. COXWORTHY:

Q. The energy cost would be higher for the industrial customers and would that be a reasonable result, though, for 2016 or 2017?

MR. FAGAN:

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A. Well it wouldn't be reasonable of the energy costs incurred to serve them.

MR. COXWORTHY:

Q. To serve the industrial customers, so it's just that it's--it's just not that it's not reasonable for 2015, it wouldn't be reasonable for 2016 or 2017 either when you look at the cost of serving the industrial customer class?

MR. FAGAN:

A. Well, in setting a 2015 test year for rate setting, you need to reflect the energy cost incurred in 2015 and the only question with respect to normalization is whether that was still reasonable for '16 and '17 and I think it is.

MR. COXWORTHY:

Q. I just want to talk a little bit about the word "normalization" because I think, again, as a layperson, I hear that word and I think that sounds good, you know, anytime you normalize something, you know, how could that not be a good thing? Does every normalization exercise turn out a reasonable result in terms of setting rates or rate design?

MR. FAGAN:

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A. Well I don't know, you need to look and see why you're doing normalization and if it's required first before you then could judge the result of the normalization. So we looked before we come up with the test year and assessed the load factor of the industrial customers, including Praxair and Vale in the 2015 test year, based on their load and the result was we didn't think a normalization was required. I think we would probably agree that there would have been a normalization required to the original 2013 test year because it was an anomaly with respect to the load factor of Vale and Praxair for that purpose, because it was one of those things, you can look at the end result and it will send you back to look and see what's going on. But if there's no normalization required, then I wouldn't go there. If there was one required, then you assess the result, whether normalization makes sense based on the result, but the sensitivity we've done on a potential normalization in this particular circumstance would produce results that don't really reflect the recovery of the fair cost to serve

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the industrial customer.

MR. COXWORTHY:

Q. So is undertaking 44 representing normalization exercise that's not necessary?

MR. FAGAN:

A. Well it's actually helpful because it shows that if you actually try to do a normalization and reflect future cost patterns in the 2015 test year, you wouldn't get reasonable results.

MR. COXWORTHY:

Q. Thank you. I'd like to move on to another area, at least for now, in relation to, I believe it's Consent No. 3, the August 2015 RSP Report. and I'm going to get into this while Mr. Patrick Bowman is still here with us because I'm conscious of your comment of how the RSP is complicated and we don't want to make it more complicated.

MR. FAGAN:

A. Mr. Bowman probably knows it better than me.

MR. COXWORTHY:

Q. Well perhaps we'd be better off if he was the one that was asking the questions, but that's not how that works here. So I'd like to turn

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to page 4 and the hydraulic production. Perhaps you could help us explain, of course, this is a snapshot, I suppose, is that fair as of August 2015 of what's going on, of course with the hydraulic variation.

MR. FAGAN:

A. We have to be careful somewhat in the use of the August or the 2015 RSP because the comparisons that were presented here are relative to 2007 test year, so the normal hydraulic production that we'd be talking about here wouldn't be what's reflected in the current test year forecast, but what was used in the 2007. So I think the cost of service hydraulic production in the '15 will probably be higher than the, slightly higher than what's in this one, so your numbers will do something different.

MR. COXWORTHY:

Q. Will change. Will the pattern stay the same?

MR. FAGAN:

A. But the math--I think it's been a very wet year, so I think we'd -

MR. COXWORTHY:

Q. Yes, you did say in your evidence earlier that

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Hydro has high water, I think, is the -

MR. FAGAN:

A. Yes, so the storage levels have been high I think most of the year, so I think--so I don't think the pattern of the numbers will be different.

MR. COXWORTHY:

Q. And before we get into the pattern, you're adverting to the fact that this is going to change because the relationships here are based on the 2007 GRA, so there will be a restatement of this as part of the 2013 process that we're into now.

MR. FAGAN:

A. In order to establish rates for 2015, for example, we talked about the load variation component, in order to run the load variation component for 2015, you take the rates coming out of 2015, compared to the fuel costs for 2015 and so you'd need to have the RSP reflecting your 2015 forecast. So the intention is to rerun the RSP for 2015 based on the approved forecast numbers coming out of the GRA.

MR. FAGAN:

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A. So that will only be after we have an order from the Board coming out of this GRA that that restatement will occur?

MR. FAGAN:

A. Yeah, I guess we would have to wait on that, yeah, we wouldn't have the numbers.

MR. COXWORTHY:

Q. You wouldn't at least normally attempt to restate it prior to that?

MR. FAGAN:

A. We're in a new world here, so I have to think about that, okay? It would be difficult because, for example, the rate proposed for Newfoundland Power in the amended application was, I don't know, 11 cents or so, but it wasn't a number that exactly reflected the test year fuel price. Historically Newfoundland Power's rate on the, it's a two-block rate, we call it a tail-block, the last block rate, is set based on the fuel price divided by the fuel efficiency factor. So in our amended application, it is $93.00 and if you divide by the proposed fuel efficiency factor of 607 kilowatt hours a barrel, you'd probably end up with a rate of around 15.3

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cents a kilowatt hour, okay? So that was the practice employed back in 2007. With the fuel prices increasing materially, when Hydro filed its original application the fuel price was probably around $106.00 a barrel in the original application, and so dividing that by the fuel efficiency factor, you'd end up with a price that was so high with regard to tail block, it actually created complications on what the first block rate would be, it might have to be negative in order to come up with the proper revenue requirement. So Hydro reviewed it and came up with an alternate approach reflective of the high fuel cost, so the price is slightly lower than the standard approach of taking the fuel price divided by fuel efficiency. In the settlement agreement, the fuel prices declined in forecast, like I say is probably down to about 70 barrels, $70.00 a barrel and so the settlement agreement provides that we use the same approach as was in the 2007 test year and divide that by the 607 and come up with a rate somewhere in the neighbourhood of 11.5 to 12 cents, so knowing what the rate would be would

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be an important component of running the RSP, so without knowing the rates for purposes of it, it would be difficult to--that would create some complexities.

MR. COXWORTHY:

Q. Sure, so there's no current plan to restate prior to? You did say we're into a new world, would there be some reason perhaps to attempt a restatement prior to getting a final order from the Board?

MR. FAGAN:

A. Well there's certainly advantages to it, okay, because in trying to phase in industrial customer rates for January, you want to get a feel for the activity in 2015 and if the hydraulic balances or the hydraulic transfers into the plan when a credit balance for 2015, even relative to the 2015 test year forecast, you could use that, that would somewhat reduce the impact of a January 1st rate change, if there's one to be implemented for industrial customers. So you could come up with an estimate, some sort of a forecast RSP for 2015. I mean, the load variation component aspect, is probably small, and well, maybe

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that could be set aside.

MR. COXWORTHY:

Q. So would that be sort of an interim restatement, is that a -

MR. FAGAN:

A. We'd have to think about it, but I think it's worth looking at.

MR. COXWORTHY:

Q. And if you were to undertake--Hydro was to undertake that, I mean, how long would it take to do that?

MR. FAGAN:

A. I think the key would be just we may want to circulate our assumptions to the parties to have an agreement on how we would do that, because Hydro making the assumptions and coming out with some numbers may just be in disagreement with the parties, so presenting the assumptions before we actually went through it and get some feedback on it would probably be a good exercise.

MR. COXWORTHY:

Q. I think asking for an undertaking probably isn't appropriate under those circumstances and I'll discuss it with counsel and we'll see if there's consensus about whether that will be useful to the parties and to the Board to have that information before the industrial customer rates, for example, are set in January 2015 (sic.), there may be other reasons why it would be useful to have that information. Obviously that's the one that's of concern immediately to the industrial customers, given that January 1, 2016 is not that far away.

MR. FAGAN:

A. I understand that and I was actually discussing this with someone this morning, we were talking about the plan for January 1st rates for industrial customers and we were struggling somewhat because of the rate stabilization being in the interim state, and then also the fact that we've got the current rules of the RSP preclude the implementation of a fuel rider and if you actually implemented a fuel rider, it would be relative to the 2007 test year, so you'd come up with a positive fuel price that may not necessarily make sense with regard to the rate design, and so I think that's probably a good idea for the

parties to work together in coming up with something.

MR. COXWORTHY:

Q. Thank you, Mr. Fagan. Going back then to page 4 of Consent No. 3 and the page on the hydraulic production variation, August 31st. I wanted to look at June, July and August and I guess I'm looking at column C in particular where we see the production variance go from, as I would characterize it, a variance in favour of the customers, to one that's not, is that a fair way of my characterizing it as we move from May into June?

MR. FAGAN:

A. The adjustments for--if we went to column E for a moment.

MR. COXWORTHY:

Q. Yes.

MR. FAGAN:

A. So the adjustments by month were credit amounts to be, were owned customers and for the period June, July and August, primarily because load requirements are lower in the, I believe, yes, load requirements are lower in the summer months and maybe also that Hydro

may be operating Holyrood for reliability purposes, I guess would be the term, to make sure they're maintaining certain reserves on the Avalon that hydraulic production may be down. So the hydraulic production -

MR. COXWORTHY:

Q. Sorry, are you spilling, is Hydro spilling water to achieve that--not to achieve, to arrive at that result?

MR. FAGAN:

A. I can't answer that, you'd have to ask I think probably either Mr. Henderson or Mr. Humphries, probably both of them could answer the question.

MR. COXWORTHY:

Q. You did mention perhaps Holyrood was being run more for reliability reasons during the summer and that that might be a driver to explain why this phenomenon is occurring in June, July and August.

MR. FAGAN:

A. Even without it though, even if it wasn't, okay, if loads were down and Hydro was providing all the loads with the combination of its hydraulic and its purchases because

it's got, I guess it's take or pay contracts for its purchases, then you wouldn't have the hydrology savings with respect to the calculation of the RSP.

MR. COXWORTHY:

Q. Is this a phenomenon that recurs in the summer months? We don't have August 2014 here.

MR. FAGAN:

A. Well, there's been a change on the system since 2007. Hydro didn't have wind generation purchases at the time. Hydro didn't have purchases from Nalcor back then. I guess the CBPP Co-gem was still there, okay, so those additional purchases provided savings to Hydro since 2007, effectively the savings would have been the cost of the purchases, the difference in the cost of the purchases compared to the test year fuel price at Holyrood back in 2007. So those 8.8 cents and if Hydro was purchasing from Nalcor for 4 cents, the 4.8 cents would have been a savings for Hydro to its bottom line between test years. But the cost of Holyrood over the years since 2007 has gone materially above the 8.8 cents, so for example, it went over $100.00 a barrel, so at

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16 cents, say, per kilowatt hour, the difference between the 8.8 cents and the 16 cents, that savings would go to customers. So customers saved because Holyrood wasn't required to operate as frequently and Hydro saved the difference between what was in the test year fuel price and the 4 cents, say for the purchases from Nalcor. So that occurred over the years, because when the RSP was designed, it was all based on the assumption that you've got hydraulic and you've got Holyrood and it's a strict one-to-one shift type thing. It's not quite in that manner currently. Now in our current test year, all the savings as a result of Nalcor purchases and say wind purchases being less than the cost of Holyrood are now reflected in the test year, but the mechanics of the RSP are still the same with regard to the assumption that the difference from the hydraulic cost of service, hydraulic production it's an assumption that it's all shifting to a Holyrood cost.

(12:45 p.m.)

MR. COXWORTHY:

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Q. And I think your extended--thank you for your explanation, it's probably answered a number of my follow-up questions, but perhaps I'll ask just one and that's in relation to column E in information 11 on page 4 and the figure that appears at the bottom of that column for August, the 7.2 million dollar figure, so is that a figure that's derived from the cost of Holyrood fuel?

MR. FAGAN:

A. I would expect the 84 gigawatt hour variance and the monthly cost, if we converted the monthly variance to the number of barrels times the 5449, I believe that should get to 7.3 million.

MR. COXWORTHY:

Q. We'll move on from Consent No. 3, I'm sorry, we will not, we'll move to page 14, to a different topic and relation, so still in Consent 3 and this is the page which deals with the industrial RSP surplus and you've been asked some questions about the phase-in, the industrial customer phase-in, the drawing down of the surplus, the RSP surplus that's been allocated for the phase-in purposes. In

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the context of the restatement of the RSP that we were talking about earlier, will that change, can you give us a sort of a high level overview and maybe we'll dig, drill down further from that as to how this will look different.

MR. FAGAN:

A. I don't think it will change. The RSP surplus disposition, Teck--there was a direction from government with respect to Teck being phased in differently from the other industrial customers, so the Board approved a specific Teck rate around a cent, okay, not exactly but approximately a cent credit, okay? So that's applied to Teck's load for, to determine that portion. The August and September numbers, could be July too, I was looking at it diagonally somewhat, the July and August numbers would have been based on the RSP surplus adjustment approved by the Board effective July 1st which would also be load base numbers of the industrial customers, so they're not impacted by any other factors within the RSP, so those should stay the same.

MR. COXWORTHY:

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Q. Does the change in the cost of Holyrood fuel, if we go to the 70 cents, this is not based on 70 cents here, is it?

MR. FAGAN:

A. No.

MR. COXWORTHY:

Q. It's based on 93?

MR. FAGAN:

A. Well it's irrelevant, the credit for industrial customers is based on, I think if we go to CA-363. Move down a little bit further, please? Okay, lines 1 to 4. Okay, the RSP surplus adjustment factors are 49 cents per kilowatt and .296 cents per kilowatt hour credit, so those numbers are applying to the industrial customer loads for those months, so they wouldn't change.

MR. COXWORTHY:

Q. Thank you. Mr. Chair, I think it would be a more efficient use of my time and I think the Board's time if perhaps we could have a five-minute break to discuss with our consultant just how much further we need to delve into these issues.

CHAIRMAN:

Q. Certainly sir.

(OFF RECORD - 12:50 P.M.)

(RESUMED - 12:59 P.M.)

CHAIRMAN:

Q. Well after a heated argument, we're going to adjourn. (Laughter) That's it, I guess, until tomorrow?

MR. COXWORTHY:

Q. That's correct. No further questions from the industrial customers, Mr. Chair.

MS. GLYNN:

Q. Yes, and we thought it was more efficient use of our time to take the afternoon and the evening to prepare for tomorrow.

CHAIRMAN:

Q. Contemplate the meaning of it all, okay.

MS. GLYNN:

Q. Yes, thank you.

Upon concluding at 1:00 p.m.

CERTIFICATE

I, Judy Moss, hereby certify that the foregoing is a true and correct transcript of a hearing in the matter of Newfoundland and Labrador Hydro's General Rate Application heard on the 6th of October, A.D., 2015 before the Commissioners of the Public Utilities Board, St. John's, Newfoundland and Labrador and was transcribed by me to the best of my ability by means of a sound apparatus.

Dated at St. John's, Newfoundland and Labrador this 6th day of October, A.D., 2015

Judy Moss

-B-

-D-

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