(9:30 a.m.)

MR. NOSEWORTHY, CHAIRMAN: Good morning. Are there any preliminary matters, Mr. Kennedy?

MR. KENNEDY: I don't believe so, Chair.

MR. NOSEWORTHY, CHAIRMAN: Okay, thank you. Mr. Hutchings ... good morning, Mr. Hutchings, have you concluded your cross, or do you still have a few questions?

MR. HUTCHINGS: Have a few other points.

MR. NOSEWORTHY, CHAIRMAN: You indicated yesterday you weren't quite sure and you'd leave it till the morning. Please continue?

MR. HUTCHINGS: Yeah, I have a few other points to chat with Mr. Hamilton about, Mr. Chair.

MR. NOSEWORTHY, CHAIRMAN: Okay, good morning, Mr. Hamilton.

MR. HAMILTON: Good morning.

MR. NOSEWORTHY, CHAIRMAN: If you could proceed please?

MR. HUTCHINGS: Yes, thank you. Just before we begin, Mr. Chair, just to update the cast of characters, behind me you'll see that Mr. Patrick Bowman has been able to join us again from Winnipeg. Mr. Bowman was here last week during the course of Mr. Osmond's cross-examination, and also with him and Mr. Deane this morning is Mr. Fred Wilcox of North Atlantic Refining who has been able to join us to observe some of the proceedings.

MR. NOSEWORTHY, CHAIRMAN: Good morning, and welcome.

MR. HUTCHINGS: Good morning, Mr. Hamilton.

MR. HAMILTON: Good morning, Mr. Hutchings.

MR. HUTCHINGS: I think before we get into any other subjects, you had one point that we had left from yesterday to check overnight, and that relates to the percentage increase in revenue proposed in respect of the non-firm rates for industrial customers. Were you able to get clarification on that?

MR. HAMILTON: Yes, the 1.8 percent shows, the latest update is correct, and the reason for the change is that in the latest forecast that was given by the industrial customers, one of the customers had allowed for generator outage energy for their 2002, and under the proposed non-firm rate, generation outage energy is cheaper than at the existing contract, so the end result, while the total demand and energy had both moved up, not the exactly the same proportions, but there's a slight load factor difference. The major difference is that the, the exceptional portion is actually cheaper now than before, so the two combined results in this 1.8 percent increase overall now, based on that revised forecast.

MR. HUTCHINGS: Okay, so is it a question of the generation outage power not having been forecast prior to September or not being priced properly in the September forecast?

MR. HAMILTON: It wasn't forecast before.

MR. HUTCHINGS: It wasn't forecast before, alright, and that generation outage power is the substitute for what used to be called the exceptional power, I believe, under the older contract?

MR. HAMILTON: That's right.

MR. HUTCHINGS: Okay, just one other point I'd like to go back to from yesterday. We had some discussion about transformer losses yesterday, and I think you provided to us an explanation as to the existing treatment of transformer losses on the system, and there was some reference to the manner in which transformer losses are to be treated, or are proposed to be treated by Hydro from this point on, but I didn't see in reviewing the transcript a concise explanation of Hydro's current position in terms of how from the date of this order on, Hydro proposes to deal with the transformer losses. Could you just briefly describe that for us?

MR. HAMILTON: Okay, on a go forward basis, losses for common transmission, common transformers will all be allocated within the normal course of common allocations. Transformers that are specifically assigned to a customer or customer class, the losses associated with that would be assigned to that class, and similarly, customer-owned transformer losses will be assigned to that class, and then the billing, the meter readings will be adjusted for customer-owned transformers, and specifically assigned transformers ...

MR. HUTCHINGS: Okay, can you just slow down for a minute so that we ... I was keeping up with you quite well with the specifically assigned and customer-owned, so if you could just take it again from there?

MR. HAMILTON: In the cost of service.

MR. HUTCHINGS: Yes.

MR. HAMILTON: Yeah, those that are specifically ... the customer-owned and specifically assigned losses are allocated then specifically to those customers, and therefore that class in the cost of service.

MR. HUTCHINGS: Right, uh hum.

MR. HAMILTON: On the billing then, for those customer-owned and specifically assigned transformer installations, then adjustments are made, will be made on the actual bills to those customers for the losses on those transformers.

MR. HUTCHINGS: Okay, so there's an extra line item on the bill to charge for transformer losses.

MR. HAMILTON: Right, where the metering is on the low side of the transformer.

MR. HUTCHINGS: Yes, okay, and that is what led us into the discussion yesterday, I guess, about the question of the same treatment being given whether the transformation in that case is going from a 230 down to the using voltage, or from a 66 down to the user voltage, or as the case may be.

MR. HAMILTON: Right.

MR. HUTCHINGS: Okay, and Hydro's proposal is to treat them all alike so that whether the transformation is from 230 down, or from 138 down, or from 66 down, all of the losses will be billed to the customer in the specifically assigned or customer-owned situation.

MR. HAMILTON: The 66 down would only be sub-transmission for Hydro rural, I believe.

MR. HUTCHINGS: Yes, I understand.

MR. HAMILTON: So therefore there would be no, none of those losses going anywhere other than for Hydro rural.

MR. HUTCHINGS: Okay.

MR. HAMILTON: It's only the 230 to 138, or 230 to 66, or if a customer-owned transformer was something specific to that customer's needs, then they would have some other low side voltage they want to use, but within the system context, it would only be 230 to 138 or 66.

MR. HUTCHINGS: Yes, okay, so if you're taking delivery of 66, then there's no extra line item on your bill?

MR. HAMILTON: If it's a common transformer. If it's a specifically assigned transformer there would be.

MR. HUTCHINGS: I thought I heard you just say that there was no issue about transformation below 66.

MR. HAMILTON: From 66 down to another voltage.

MR. HUTCHINGS: Yes.

MR. HAMILTON: Yeah, you said down to a lower voltage when you got below 66, and I said any lower than 66 would only, the only place that there's transformation below 66 down, is either a Newfoundland Power system or a Hydro rural system.

MR. HUTCHINGS: Yes.

MR. HAMILTON: And that's there own losses anyway. They've already taken delivery by then. Our metering would be at 66 and up.

MR. HUTCHINGS: Okay, that's fine, so there's no issue about a transformer charge, a transformer loss charge below 66?

MR. HAMILTON: No.

MR. HUTCHINGS: No, okay.

MR. HAMILTON: Other than some of the industrial customers might have, the low side of their transformer might be something below 66. The lowest losses are being taken care of because the metering point is taken up back to the 230. I believe Stephenville doesn't take, their low side is not 66, for example.

MR. HUTCHINGS: That's right, so the transformer charge in the Stephenville situation then for the loss, what portion of the step down is being charged to them?

MR. HAMILTON: For the full losses on their transformers.

MR. HUTCHINGS: Full, yeah.

MR. HAMILTON: They control what ... and that's one of the issues on the fairness side, is that because you need operation they might want a different low side voltage than another customer, so I just point out, the characteristics of the transformer dictate the losses, so that by having them take care of those specific losses it's more equitable. They control the configuration of the transformers.

MR. HUTCHINGS: Uh hum, but it's the configuration of the system that dictates that they are taking at 230 as opposed to 66?

MR. HAMILTON: Yes, both transmission is 230 and 138, so they take one of those two.

MR. HUTCHINGS: Yeah, and those, as we said yesterday, who happen to have the benefit of there being a common transformer to get it down to 66, thereby get the advantage.

MR. HAMILTON: That's one of the ... if it's common, it's common to all. It's the transformer, by virtue of being classified as common, must provide a benefit to more than one customer.

MR. HUTCHINGS: Yes, okay, alright. We've had some discussion in the course of the hearing, Mr. Hamilton, about the comparison between the Interruptible B provision, which the Abitibi mill in Stephenville has in place, and the generation credit that is given to Newfoundland Power in respect of its own generation, can you explain for us how the cost of the Interruptible B contract is assigned under the cost of service? There is an amount of money obviously that's paid through Abitibi for the Interruptible B service that's being provided by them, if you will, and that cost is allocated under the cost of service. How is that allocated?

MR. HAMILTON: I'll just check the ... I believe it's assigned with the generation cost.

MR. HUTCHINGS: I think if we look at page 94 of 94 of **Mr. Brickhill's last cost of service study**, there is in fact a line item there for interruptible demand.

MR. HAMILTON: Yes, and that's the Interruptible B.

MR. HUTCHINGS: Okay, and that's the $1.298 million that's shown in Column 2, at line 4.

MR. HAMILTON: That's correct.

MR. HUTCHINGS: And under Column 3, that is all allocated to production demand.

MR. HAMILTON: That's correct.

(9:45 a.m.)

MR. HUTCHINGS: Okay, so what is the effect of that allocation to production and demand of that amount of money? Who actually pays that as a result?

MR. HAMILTON: That would be allocated on the basis of, the same as all production demand costs, and therefore allocated based on, in the proposed 2-CP allocator.

MR. HUTCHINGS: Right, and just in very general terms, as between Newfoundland Power and the industrial customers, and the rural customers, what sort of percentage would that give rise to?

MR. HAMILTON: I'm not sure (inaudible) percentage. The basis for that would be on page 38 of 94.

MR. HUTCHINGS: Okay.

MR. HAMILTON: And there in the bottom section you can see the allocation ratios.

MR. HUTCHINGS: Uh hum.

MR. HAMILTON: So that's the 78.18 percent of production demand goes to Newfoundland Power, 14.6 goes to industrial firm, and the remaining .0719 is allocated amongst the various rural rate classes on the island.

MR. HUTCHINGS: Okay, and the portion that is allocated to rural rate classes, a significant amount of that gets reallocated back as part of the deficit to Newfoundland Power, correct?

MR. HAMILTON: Newfoundland Power and Labrador.

MR. HUTCHINGS: And the Labrador interconnected customers, okay.

MR. HAMILTON: Yes.

MR. HUTCHINGS: Alright, can we try to follow through then in the same way how the costs associated with the generation credit to Newfoundland Power are treated under the cost of service study? First of all, there is no line item to which we can point to see the cost of that, is there?

MR. HAMILTON: No.

MR. HUTCHINGS: Okay, and what are the various effects to the cost of service study that the generation credit has?

MR. HAMILTON: Well, the generation credit basically, because it effectively reduces Newfoundland Power's peak for assignment purposes, they're allocated a lower portion of the production demand costs than would otherwise happen if you didn't apply the demand credit.

MR. HUTCHINGS: Uh hum.

MR. HAMILTON: So therefore, anything that's classified and allocated, classified as demand and allocated using the CP allocator, then they get a lower proportion and therefore a higher portion goes to the industrial customers or to the island interconnected rural customers.

MR. HUTCHINGS: Okay, and which of the costs are actually allocated by the CP allocators?

MR. HAMILTON: The CP allocators are based on, are used for production demand and the transmission demand.

MR. HUTCHINGS: Okay, so as a result of the generation credit there is less production demand and less transmission demand assigned to Newfoundland Power than otherwise would have been.

MR. HAMILTON: That's correct.

MR. HUTCHINGS: And there, and since this is a closed system, obviously, there is more of the production demand costs and transmission demand costs, assigned to the industrial customers as a result?

MR. HAMILTON: That's correct.

MR. HUTCHINGS: Okay, and in the absence of the credit to Newfoundland Power, is it correct to say that the entire amount which is the cost to the system of that production demand credit would simply stay as a cost with Newfoundland Power?

MR. HAMILTON: If there was no credit given to them?

MR. HUTCHINGS: Uh hum.

MR. HAMILTON: Yes.

MR. HUTCHINGS: 100 percent?

MR. HAMILTON: Yes.

MR. HUTCHINGS: Yeah. Mr. Hamilton, I'd like if we could to look for a moment at the **pre-filed supplementary testimony of Mr. Osler**, September 12th, 2001, and at page

2 in Section 2.2, there's a discussion about expected 2002 rate changes, and have you had the opportunity to review this evidence?

MR. HAMILTON: I've read the evidence, yes.

MR. HUTCHINGS: Okay, Mr. Osler begins with the proposition that Hydro's application is not consistent with what one might expect would be the relative rate changes between Newfoundland Power, the industrial customers, and rural customers that should occur in 2002 based upon Hydro's rate history in the last decade. Would you agree with that?

MR. HAMILTON: I guess, I don't know if everybody will reach the same conclusion.

MR. HUTCHINGS: Uh hum.

MR. HAMILTON: I can't speak for everybody's expectation. I understand we did some calculations, and I'm sure there's more to be done to explain why it is what it is. I think the ... but I can't speak to what people's expectations would have been.

MR. HUTCHINGS: Okay, well what were your expectations at the time that you began to try to design the rates for 2002? Would you have expected there to be a higher relative increase for industrial customers than for the utility customer?

MR. HAMILTON: All things being equal, yes, I would have expected there would.

MR. HUTCHINGS: And why was that?

MR. HAMILTON: Because, a lot of the increase is fuel related. They have a higher load factor and therefore they'll attract more fuel cost ...

MR. HUTCHINGS: Uh hum.

MR. HAMILTON: ... than Newfoundland Power. The system hadn't changed a whole lot from a demand capacity point of view, so the major increase in cost was energy expense, and for a higher load factor customers, it would tend to attract a higher portion of those costs.

MR. HUTCHINGS: Yes, and were there any factors of which you were aware that would tend to offset that?

MR. HAMILTON: The fact that there's also been changes in methodology, vis-a-vis 1992, the last time there was a hearing, that would then add some other impacts on it. The fact that over ten years different plant has been added in various locations and there's been some change in allocations. That would tend to add some other impacts to it, but from the point of view, if everything was stable type of thing and just, you know, as in (inaudible) proposed methodology an then we started putting in the new numbers for the revenue requirement, that if we expected that that was the methodology was set, that there would be an increase higher for industrials than for Newfoundland Power. The impact of the different plant allocations and the impact of the methodology changes from the interim to the generic then had some ups and downs. Similarly the, the customers themselves, the forecast usage patterns have change somewhat since '92 and I don't ... the load factor for industrial customers hadn't changed a lot and Newfoundland Power over the years, their load factor has been steadily increasing. As noted, their demand is virtually the same now as it was in '92 but their energy has gone up, and I think therefore their load factor must have increased, and that's just between the original filing and the new revised filing, but just over a period of time their load factor will have increased, and that also will tend to pull their rate increase portion down, so there's many different things happening. I noted that Mr. Osler identified several of them but he didn't factor in all of them, and so depending on what calculations you use, you can certainly come to different impacts.

MR. HUTCHINGS: Well, let's deal with some of the points that you have mentioned. The impact of the 1993 cost of service study, I think we spoke briefly about yesterday and that was estimated on the basis of numbers that Hydro had produced by Mr. Osler to be about $1.75 million. It should have been a benefit to industrial customers.

MR. HAMILTON: The number I referenced yesterday was something like that.

MR. HUTCHINGS: That's at page 7 of Mr. Osler's testimony.

MR. HAMILTON: That's in reference to IC-90 I believe.

MR. HUTCHINGS: Yes.

MR. HAMILTON: IC-90 is not a comparison of '93, that's ...

MR. HUTCHINGS: 2002.

MR. HAMILTON: As of 2002 comparison.

MR. HUTCHINGS: Yes, uh hum.

MR. HAMILTON: And it's not, that's a comparison, as I understand it, from going ... actually if I can see IC-90, IC-90 is a comparison of the proposed methodology to the interim methodology.

MR. HUTCHINGS: Right.

MR. HAMILTON: It's not the generic methodology to the interim methodology.

MR. HUTCHINGS: No, but I mean the methodology that Hydro is using for the purpose of this application is the proposed methodology.

MR. HAMILTON: That's correct.

MR. HUTCHINGS: So simply the application of the proposed methodology as opposed to the interim methodology should produce this change, correct?

MR. HAMILTON: That causes that change, that's right.

MR. HUTCHINGS: Yes.

MR. HAMILTON: But it's not the generic methodology ... yesterday we explained the difference between interim, generic and proposed.

MR. HUTCHINGS: Right.

MR. HAMILTON: So the proposed has the plant reassignments and all aspects that's changed since '93.

MR. HUTCHINGS: Yes, so in fact with the plant allocations and so on there should, in fact, have been an even greater benefit to the industrial customers, should there not? The proposed methodology includes, for instance, the allocation of the Great Northern Peninsula transmission line to common.

MR. HAMILTON: Yes.

MR. HUTCHINGS: Yes, and if that was not the case, if that allocation or assignment is in fact found to be incorrect, then that would in fact reduce further the costs assigned to the industrial customers, would it not?

MR. HAMILTON: Yes, it would.

MR. HUTCHINGS: Okay, so this comparison relative to the 1993 cost of service, if anything, understates the effect of what would have otherwise been expected, would you agree?

MR. HAMILTON: I can't speak for what was to be expected.

MR. HUTCHINGS: No, okay, but if in fact we were looking at the interim compared to the generic, this 1.75 number would be bigger because the generic did not include the allocation of the transmission line to common.

MR. HAMILTON: If you went back to the '93 ... yes.

MR. HUTCHINGS: Yes.

MR. HAMILTON: If you changed the plant allocations.

MR. HUTCHINGS: Yes.

MR. HAMILTON: Uh hum, well that's not methodology change, that's an allocation change.

MR. HUTCHINGS: No, no, I understand, yeah, yeah, but the 1.75 number is the proper identification of the change in methodology, but includes changes in plant allocations as well.

MR. HAMILTON: From the '93 hearing.

MR. HUTCHINGS: Yes, uh hum, and if the allocations were in fact changed, that would in fact add additional monies that the industrial customers would have saved.

MR. HAMILTON: It reduces the cost assignment to that.

(10:00 a.m.)

MR. HUTCHINGS: Yes, okay, you did not mention in your discussion of the factors that would have been expected to affect these rate changes, the issue of the rural deficit, and would you not agree with me that there should have been expected to be an additional cost assigned to Newfoundland Power as a result of the reallocation of rural deficit, in order to make up that portion of the rural deficit which had previously been paid by industrial customers prior to 2000.

MR. HAMILTON: Assuming the deficit was the same overall magnitude, yes.

MR. HUTCHINGS: Yes, okay, so that's the direction in which that should have been going.

MR. HAMILTON: Assuming the deficit was increasing, yes.

MR. HUTCHINGS: Yes, I understand that.

MR. HAMILTON: Uh hum.

MR. HUTCHINGS: Mr. Osler has also dealt with the issue of the interest coverage which was implicit in the rates set for industrial customers in 1994, and that was in fact a higher interest coverage than was implicit in the rates set for the utility customers in 1992, wasn't it?

MR. HAMILTON: The rates in 1992 were set at a target of 1.08.

MR. HUTCHINGS: Uh hum.

MR. HAMILTON: I'm not sure what the actual coverage was in '94 but it wasn't 1.08, I'm not sure if it was above or below that. As in costs for different from forecasts costs in '94, so I assume all customers had a somewhat different coverage in '94 versus the '92 (inaudible).

MR. HUTCHINGS: No, I understand that, but there was no rate change in 1994 for the utility customers.

MR. HAMILTON: No.

MR. HUTCHINGS: No, but there was a rate change in 1994 for the industrial customers.

MR. HAMILTON: That's correct.

MR. HUTCHINGS: And that, those rates were set then to produce for Hydro a 1.16 interest coverage, is that correct?

MR. HAMILTON: That's correct.

MR. HUTCHINGS: So if, and in the current application your three percent return on equity is proposed to produce a 1.08 interest cover, correct?

MR. HAMILTON: I think that's what the arithmetic ... (inaudible) in that order of 1.08 ball park, 1.08 or 1.09.

MR. HUTCHINGS: Okay, so on the natural assumption that Hydro now is a fully regulated utility should be getting the same interest coverage on its sales to all its customers, one would have expected that industrial rates should be reduced in order to bring them back to a level that would produce only a 1.08 as opposed to 1.16, isn't that correct?

MR. HAMILTON: It's certainly moving the coverage down but reduces the revenue requirement, yes.

MR. HUTCHINGS: Yeah, okay, is there any other factor that you can identify that would tend to imply a greater increase for the industrial customers aside from the issue of their being assigned additional energy costs?

MR. HAMILTON: The effect that their base rate has gone down since the 1992 time period, they're starting off with a lower number, so even the same dollar increase would be a proportionately higher percentage for that purpose, and as I pointed out, the relative load factors of the industrial, vis-a-vis Newfoundland Power and the island interconnected system, to the extent that the other ... their load factor hasn't changed as much as the others and therefore it changes the weighting of the cost and I don't recall seeing any allowance for that in Mr. Osler's calculations and I think that looking back at the sensitivity to the revised forecast for Newfoundland Power between the original filing and our subsequent filing, that there was a much larger change in load factor from '92 to 19 ... to our original filing even, that I think if the system hadn't changed, and Newfoundland Power's load factor was indeed the same now as in '92, that the relative increases probably would have been more in line with having much the same percentage increases, maybe even more Newfoundland Power. I haven't ... we've run the cost of service with those numbers in it, but just on the relative sensitivity. I think the load factor shifted a fair bit.

MR. HUTCHINGS: Uh hum, yeah, and I have to agree with you that the load factor is very significant in this ... the initial projection, I think, we have for your original filing for the firm energy for industrial customers was an increase of 10.4 percent, and this I think shows up on the first page of your supplementary evidence, your last supplementary evidence, October 31st, and the original submission was at 10.4 percent for industrial firm power.

MR. HAMILTON: Yes.

MR. HUTCHINGS: And then with the September revision which resulted primarily from the mis-allocation of costs related to rural operations, I understand that percentage reduced to 8.5 percent.

MR. HAMILTON: That's correct.

MR. HUTCHINGS: And then with the October revision we go back up again to 10 percent, and that effect is primarily a result of the changed load forecast for Newfoundland Power, isn't it?

MR. HAMILTON: That's a portion of it. Also the higher fuel cost from the latest fuel forecast and some (inaudible) costs that were changed, but I think that that was a contributing factor in that shift.

MR. HUTCHINGS: Well, it's more than one percent of the 1.5 percent, isn't it?

MR. HAMILTON: It's somewhere in that ball park.

MR. HUTCHINGS: 1.2 perhaps of the 1.5?

MR. HAMILTON: I'm not sure exactly what the number is now. I have it here somewhere. Finding it might be a challenge but I have it.

MR. HUTCHINGS: I think that may be in Mr. Osmond's evidence from the 31st.

MR. HAMILTON: It's approximately ... not using a calculator, but I'd say about 1.2 percent.

MR. HUTCHINGS: Yes, so it's 1.2 of the 1.5 relates to the change in forecast from Newfoundland Power.

MR. HAMILTON: Yes.

MR. HUTCHINGS: Which is primarily related to the fact that their peak came down and their energy went up producing a significant change in their load factor.

MR. HAMILTON: That's correct.

MR. HUTCHINGS: Okay, do you have any input into what forecast for Newfoundland Power is actually used for the purpose of the cost of service study, or does that come to you from Mr. Budgell's department?

MR. HAMILTON: Mr. Budgell's department takes care of the forecast inputs that we use.

MR. HUTCHINGS: Okay, so you have no discretion within your organization to question that. That just comes from Mr. Budgell.

MR. HAMILTON: There is possibility for it ... we get numbers, like any numbers that go in the cost study, if we see a trend or something that looks a little bit anomalous we might question it to the extent that then they verify it and confirm the numbers we use, then we're sure it's the numbers, and then at that point we accept it, yes.

MR. HUTCHINGS: Okay.

MR. HAMILTON: So discretion was the term that kind of got me.

MR. HUTCHINGS: Okay, no ...

MR. HAMILTON: A change, we'll always go back and kind of wonder why.

MR. HUTCHINGS: Uh hum, okay, it strikes me that from the original submission, the 10.4 percent to the September revision, the 8.5 percent as regards the industrial firm, there's a 1.9 percent, almost two percent change. Did any of the numbers that you had with the original submissions strike you as anomalous given that an error was subsequently found that made that large a change in the way the original submission should have been?

MR. HAMILTON: I guess the, any time you see a shift in the results I find that you always go back and you look for things, and verify things, and look for anything that might be more or less objective to test if the assumptions were right, and that sort of thing, so you always compare results of your latest versus past, and if there is any kind of movement you always wonder why, and in that context, there were various other additions to that cost of service before the one that was filed for those very reasons that as the first edition rolled off, people looked at it and said, okay, that looks interesting, whatever. Things were tested, reviewed, some things revised. I wouldn't try to estimate how many cost of service studies were between the first and the last. There were several for various reasons and others for testing purposes, but as it was getting fine tuned and looking at the final revenue requirement numbers, all the major cost categories were reviewed with the relevant departmental managers and directors and so at the end of the day the results were explained and so it was accepted. As you, as over time, more people look at things and sometimes suggest file it again, and through additional conversations and testing and more actual results for the year come in, I guess they found these results to be a little bit off and they went back and inside accounts found a couple of more mistakes, so that's the history of those corrections.

MR. HUTCHINGS: If we look at numbers, I mean from, on 10.4 percent that 1.9 percent error is, what, 17 or 18 percent, do you agree with that?

MR. HAMILTON: No, it's a 1.9 percent movement in cost.

MR. HUTCHINGS: Yeah, but what I'm asking you is what is, what percentage of 10.4 is 1.9?

MR. HAMILTON: 1.9 over 10 percent would be something approaching 20 percent, but 1.9 percent over four percent would be a much bigger number, but it's still only 1.9 percent.

MR. HUTCHINGS: No, I understand that, but I mean on an order of magnitude here, I mean we're looking at an error of almost 20 percent in the amount of the increase and that was not picked up as being anomalous by Hydro, correct?

MR. HAMILTON: It's not the percentage increase that we would look at, it would be the total dollar revenue requirement assigned to them and in that context, given the other things that were going on, the, you had 10.4 versus 6.7 versus the other numbers, they were all somewhat comparable ranges.

(10:15 a.m.)

MR. HUTCHINGS: So there were no flags raised from your department with those original submissions as you saw them?

MR. HAMILTON: The cost of service was constantly being reviewed and within the accounting numbers I understand that they were almost being reviewed on a monthly basis as actuals came in and as errors were identified, whether it municipal tax allocations, that sort of thing, again, a lot of the errors were more a function of getting adapted to the JDE system that some things were identified as having been missed and they got picked up as we went along.

MR. HUTCHINGS: Okay, I just want to move now, Mr. Hamilton, briefly to the area of the demand energy rate for Newfoundland Power. This is the subject that you dealt with in an earlier life as well, isn't it?

MR. HAMILTON: Yes, it is.

MR. HUTCHINGS: Okay, I'd just like at this point, Mr. Chair, to distribute an extract from the transcript of the hearing before this Board on February 6th, 1992, where Mr. Hamilton was giving evidence at that point on behalf of Newfoundland Power, and this is pages 796 through 805 of this particular transcript.

MR. KENNEDY: I believe it's IC-5, Chair.

MR. NOSEWORTHY, CHAIRMAN: Thank you.

MR. HUTCHINGS: Do you recognize that as being the transcript of your evidence given at or about that time, Mr. Hamilton?

MR. HAMILTON: Yes.

MR. HUTCHINGS: Okay, and you are the person, obviously, identified as Hamilton and generally speaking, given the answers in this transcript, and the person described as Greene is, in fact, Maureen Greene, who then was, and still is, counsel for Hydro, correct?

MR. HAMILTON: That is correct.

MR. HUTCHINGS: Okay, times have changed. At that point, Mr. Hamilton, it was, in fact, Newfoundland Power that was requesting a change in the rate structure to provide a demand energy rate from Hydro to Newfoundland Power, is that correct?

MR. HAMILTON: I believe so.

MR. HUTCHINGS: Yes, okay, if you look at the fourth and fifth line down in Ms. Greene's first question at the top of page 796, she asks you that, "Am I correct in saying that Newfoundland Power initially requested that such a rate, that is to say the demand energy tariff structure be designed for Hydro to charge Newfoundland Power?", and you indicated on behalf of Newfoundland Power that, "Yes, we did". Perhaps we can move down then to the next question and answer where Ms. Greene then asked you to advise the Board why that request was made, and perhaps you could read that answer into the record for us?

MR. HAMILTON: I believe it was done for several reasons. One reason was that it's, we have demand energy rates for a portion of our customers and yet we were having great difficulty getting those rates properly structured because of the purchase price being a flat energy rate and (inaudible) many of our general service rates, in effect became such that we were, had to sell it for less than we were paying for it on an incremental kilowatt hour basis. When you include a demand charge component it was okay. If that condition continued, it could force us to have to adopt an energy only rate for large customers which meant there'd be no cost put on demand for those customers and that would clearly send bad price signals to our customers. That was one issue. And I guess that back in the time we first started working on it, that was probably the only issue. Since that time a big other issue that's come along is demand side management activities, and the problem of Newfoundland Power attempting to implement programs to achieve some demand efficiency gains, if you would, reduce demand on the system, improve the efficiency of the overall system, and these costs would be borne by the company. The impact of those changes or improvements would only flow through to the extent that they're achievable through the Rate Stabilization Plan and back to customers. There is no offsetting revenue impact to offset that expense, so it's desirable to have a demand charge that therefore would more quickly react to those changes so that in effect we would get some reduced purchased power expense to offset the increased capital costs of being involved in such programs.

MR. HUTCHINGS: The transcript carries on then and there's some discussion of these two principal reasons, and some discussion of the price signal. The fourth answer from the bottom, you indicated ... "we want", and this is on the next page 797 ... we want to clearly tell them that capacity has a cost, and that was the purpose of the demand energy rate that Newfoundland Power was sending to, was using for its general service customers at the time, correct?

MR. HAMILTON: Fourth answer?

MR. HUTCHINGS: Fourth from the bottom. It's the fourth item from the bottom, it's the second answer from the bottom.

MR. HAMILTON: We want to clearly tell them that capacity has a cost. That was to Newfoundland Power's customers.

MR. HUTCHINGS: Yes, uh hum, yeah, okay, and in your next answer there, perhaps you could read that into the record as well, "So that they will use their plants".

MR. HAMILTON: So that they will use their plants more efficiently, that they will not just kind of, what the heck, turn on all the lights and leave them on. If there is no demand charge there would be no reason to worry about what they used at a point in time, and therefore it could leave to several, to severe needle peaks on the whole system.

MR. HUTCHINGS: Okay, what's a needle peak?

MR. HAMILTON: That would be a sharp short-term peak, lasting short duration but it would, I guess, require all capacity on the system.

MR. HUTCHINGS: Yes, okay, and what's the danger in a needle peak? What's the downside?

MR. HAMILTON: You have to build more capacity to meet that peak.

MR. HUTCHINGS: Uh hum, okay, and any, any customer, whether it was the actual end user or a utility that was distributing, would have good reason to avoid needle peaks if there was a demand charge associated with their usage, correct?

MR. HAMILTON: The retail customer?

MR. HUTCHINGS: Either, either the retail customer or a utility.

MR. HAMILTON: If there's a demand charge there, yes, you're going to avoid needle peak.

MR. HUTCHINGS: Okay, but if there was a flat basic energy charge, it wouldn't make any difference to you, would it?

MR. HAMILTON: In the short-term, it wouldn't cause you as much concern.

MR. HUTCHINGS: No, okay, alright, over to the bottom then of page 798 of the transcript you have before you, four paragraphs from the bottom there's a question and it says ... and the hope is that they will get their right pricing or they will conserve their energy and their demand on load and that will take, be taken into account in your rate design as well as the future system expansion, and could you just read your answer into the record?

MR. HAMILTON: Presuming the customers have to make conscious decisions and to the extent that they make these decisions it obviously affects the load on the system and the growth rate of the system.

MR. HUTCHINGS: Ms. Greene moves on then in her cross-examination to the second reason which dealt with demand side management and that discussion carries on then for several other pages and over on page 801 she then moves to the question, and this is in the second paragraph from the top, after the word, Greene, moves to the question of the demand energy split tariff and the Newfoundland Power proposal, that it be introduced with the suggestion of a no ratchet clause, and it was at that time, I believe, the position of Newfoundland Power that there should not be a ratchet clause in the demand rate, is that correct?

MR. HAMILTON: That's correct.

MR. HUTCHINGS: Okay, can you just explain for us what a ratchet clause is, what it does?

MR. HAMILTON: Well a ratchet clause typically will tie the, the monthly or longer term demand payment to a, possibly a single event, it could be the full demand and then pay for it for the next 12 months or for the rest of the season. It could be some percentage of it, it could be relative to a contract amount but basically it limits the fluctuation in billing demand as opposed the current month demand. It could vary, you know, two to one over the year. A ratchet would limit that amount of movement, either to zero or some percentage.

MR. HUTCHINGS: So that if there was a ratchet clause based on maximum demand and Newfoundland Power, for instance, in this case, hit its maximum demand in the month of November, or in the month of January at 450 megawatts, then that would be the billing demand for the entire year under a standard ratchet clause, is that correct?

MR. HAMILTON: Yes, that was the nature of the clause, yes, full ratchet for a twelve month period.

MR. HUTCHINGS: And what that does for Newfoundland Hydro in that situation, of course, is to provide a stable income stream because it knows what the demand charge is going to be throughout the entire year, correct?

MR. HAMILTON: It will give you a stable revenue stream once that demand has been hit, and whether that demand is as forecast for costing purposes is still, that variability is still there.

MR. HUTCHINGS: And the type of contract that the industrial customers have is a sort of ratchet as well, isn't it, because you're picking up power on order and you pay on that basis for the entire year, whether or not you take the entire demand.

MR. HAMILTON: It's a contracted demand which is a contract for the whole year, it's a fixed amount, yes.

MR. HUTCHINGS: Yeah, and that provides a stable revenue stream to Hydro for the year.

MR. HAMILTON: Yes, it does.

MR. HUTCHINGS: Okay, and at this time, obviously Hydro wanted to have a ratchet clause and Newfoundland Power proposed no ratchet clause, correct?

MR. HAMILTON: If there's to be a multi-part base, that Hydro proposed a ratchet demand.

MR. HUTCHINGS: Yes.

MR. HAMILTON: They didn't propose a demand rate.

MR. HUTCHINGS: No, it wasn't Hydro's proposal that there be a multi-part rate at that time, but that if there was a multi-part rate there would be a ratchet clause included with it.

MR. HAMILTON: That was the recommendation.

MR. HUTCHINGS: Okay, and Hydro had proposed an option for a multi-part rate on the basis that Newfoundland Power had looked for a demand energy rate at the time, correct?

MR. HAMILTON: Yes.

MR. HUTCHINGS: Okay, has anything happened between 1992 and today that would change the ability of Newfoundland Power to send the proper price signals by way of a demand energy rate?

MR. HAMILTON: Newfoundland Power to send ...

MR. HUTCHINGS: Its price signals to its customers.

MR. HAMILTON: To its customers? Not that I'm aware of. They have, I believe they've, at their hearings they have addressed their rate design, and I understand that they have demand energy rates for their customers.

MR. HUTCHINGS: Uh hum, okay, as they did in 1992?

MR. HAMILTON: Yes.

MR. HUTCHINGS: And essentially their rate structure is what it was in 1992.

MR. HAMILTON: Not exactly, no.

MR. HUTCHINGS: In what particulars would it be different?

MR. HAMILTON: I believe their demand, the demand is not the same as it was then in that they eliminated the (inaudible) monthly demand with no limitation on the rate class that its in. Back in '92, if they were in a rate class that was for 110 to 1000 kVa customer, that the demand could never go below the minimum for that rate class of 110, and they changed that in the nineties.

MR. HUTCHINGS: Changed it in what way?

MR. HAMILTON: That demand could go down to 70, 80, whatever, for a current billing, so there's more ... you've got more flexibility in the demand to make (inaudible) recognize seasonality variations and that results in a higher demand charge, so I guess you could ... the demand charge has increased somewhat since '92. It's a higher number now.

(10:30 a.m.)

MR. HUTCHINGS: Okay, would you say that there is today a significantly reduced need for conservation of electricity by way of demand side management than there was in 1992?

MR. HAMILTON: I don't think there's a difference in need, I think that back in the late eighties, early nineties, DSM and that type of thing was, well conservation was there in the eighties, and it then took different shapes in the DSM, and I think that back in the earlier years it was felt that consumers needed to be informed a bit in trying to make decisions. I think that since that time that what's happened is that a lot of the suppliers of the equipment that customers use have gotten more knowledgable (inaudible), so that the, it's easier for the ultimate consumer now to reduce their energy consumption. It's in effect being done for them, in that there are more efficient appliances, there are more options out there that the manufacturing industry has undertaken and I think consumers are, I wouldn't say they're wiser, it's probably more a case of it's more ... it's been around long enough they've kind of grown with it. For example, I mean cars have totally changed since the eighties. There was ... efficiency, it's treated in a different context than it was back in the eighties, but vehicles are no less efficient than they were in the eighties, and you don't see V-8's out there anymore, that type of thing, so I think the nature, the maturity of the players, if you would, have now ... it's sort of common business sense, for lack of a better word, (inaudible) change lifestyles much the same way as they did back then.

MR. HUTCHINGS: Is electricity more or less expensive now than it was then?

MR. HAMILTON: It depends on the customer. As in ... industrial rates right now are lower than they were in '92.

MR. HUTCHINGS: Uh hum, no I mean in terms of the cost of producing electricity. Are they spending more or less money today to produce electricity than it was in 1992?

MR. HAMILTON: The price of oil right now is higher, so the cost of generation at Holyrood is higher.

MR. HUTCHINGS: Uh hum, and having exhausted most of the really economical Hydro projects in the province, the prospect is for higher cost in the future rather than lower cost, subject always to the price of oil, correct?

MR. HAMILTON: That is correct.

MR. HUTCHINGS: Okay, I think yesterday, Mr. Hamilton, we agreed that there had been an increase in the part of the industrial customers' rate that arises out of the RSP from 2002, or proposed to be 2002 over 2001 from 5.14 mills to ... 5.14 down to, from 2.8, is that correct?

MR. HAMILTON: There's an increase ... you said decrease, there's an increase from 2001 to 2002 from 2.8 to 5.14.

MR. HUTCHINGS: Right, okay, and on the basis of 1.47 million kilowatt hours, which the industrial customers use, we're talking about $3.455 million, a simple multiplication, can you say how much more money we have to pay out as a result of that?

MR. HAMILTON: That sounds about right, yeah.

MR. HUTCHINGS: Almost three and a half million dollars.

MR. HAMILTON: Uh hum.

MR. HUTCHINGS: And in your Table 2, on page 9 of your revised evidence, we see that the change in the firm rate here from the existing rate producing $45.5 million and the proposed rates $50.075 million, is a change of $4.5 million, correct?

MR. HAMILTON: The numbers on the table here, yes.

MR. HUTCHINGS: Yeah, okay, and that, of course, doesn't include the change in RSP amount, does it?

MR. HAMILTON: No, it doesn't.

MR. HUTCHINGS: Okay, so the rates that are proposed overall here mean an increase for the industrial customers from 2001 to 2002 of an amount in excess of $8 million, correct?

MR. HAMILTON: I'm not sure what their cost is in 2001, but 2002 at existing versus proposed rates here, (inaudible) 2001, I'm sorry.

MR. HUTCHINGS: Yeah, from 2001 to 2002 this ... okay, so this ...

MR. HAMILTON: Both of these are 2002.

MR. HUTCHINGS: Okay, this is proposed for 2002.

MR. HAMILTON: Right.

MR. HUTCHINGS: So the result of the proposed increase in base rates is an extra $4.5 million in 2002 for the industrial customers.

MR. HAMILTON: Yes.

MR. HUTCHINGS: And they will be paying in 2002 an additional $3.455 million as a result of the increase in the RSP portion of the rate, correct?

MR. HAMILTON: The number you gave me there earlier, yes.

MR. HUTCHINGS: Yes, okay, so combine the two of those and out of the pocket comes an extra $8 million from the industrial customers in 2002, correct?

MR. HAMILTON: Compared to what it would be on existing rates, yes.

MR. HUTCHINGS: Yeah, okay, thank you, Mr. Hamilton, those are all the questions I have, Mr. Chair.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Hutchings. Thank you, Mr. Hamilton. We'll move now to the Consumer Advocate please? Mr. Browne, will you be conducting this cross examination?

MR. FITZGERALD: Actually, Mr. Chairman, we both will. I'll commence, if that's okay?

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Fitzgerald. Good morning.

MR. FITZGERALD: Good morning. Good morning, Mr. Hamilton.

MR. HAMILTON: Mr. Fitzgerald.

MR. FITZGERALD: Mr. Hamilton, if I could direct you to page two of your **pre-filed evidence** please.

MR. HAMILTON: The original or revised?

MR. FITZGERALD: Your original. Now at page two you've identified rate design criteria, and that rate designers, which I assume you are one, generally adhere to, or attempt to adhere to, is that correct?

MR. HAMILTON: These are some of the objectives that you'd use, yes.

MR. FITZGERALD: Okay, and these objectives are found in the academic literature, as you refer to, James Bond Bright, at the top of the page. So this is not something that Hydro has identified as necessary criteria, this is something that has been present, time-honoured criteria.

MR. HAMILTON: Yes, Bond Bright, I guess, was the first one to put it in a book for everyone to see, and these aren't exactly his words, his original is, I guess, eight principles, and his re-write had, I think, ten principles, and these are a paraphrase of them in the context of what I thought ones that guided our situation.

MR. FITZGERALD: Okay, so these are front and centre in Hydro's mind when they're designing rates?

MR. HAMILTON: Yes.

MR. FITZGERALD: Okay, now you discussed some of these criteria, and in particular you refer to on page two the concept of revenue requirement, market efficiency, cost-based rates, stability and administrative practicality, and you discussed these briefly with counsel for the Industrial Customers yesterday, but I want to quickly go through these again in the context of the RSP or how the RSP impacts on these criteria which Hydro has in mind when they're designing rates, okay.

MR. HAMILTON: Okay.

MR. FITZGERALD: Could you comment then, having a look at the revenue requirement criteria which Bond Bright has outlined. How does the RSP impact on that?

MR. HAMILTON: Well the RSP as it's structured in Hydro's case assists in the attainment of revenue requirement in between hearings because it covers the major fluctuations in the, the primary driver being fuel costs, quality, and revenue variance.

MR. FITZGERALD: Is that a positive impact or a negative impact?

MR. HAMILTON: That's a positive impact from Hydro's point of view.

MR. FITZGERALD: What about the situation though where we're anticipating a $100 million shortfall in the RSP next year, does that flow through to your revenue requirement in any way, impact it negatively?

MR. HAMILTON: Revenue requirement is the total revenue that we need to meet our revenue requirements. The balance in the RSP, I guess it's more of a deferral account, but from an accounting point of view it's been recognized as being, meeting Hydro's revenue requirement.

MR. FITZGERALD: On an accrual basis, not on a cash basis.

MR. HAMILTON: Not on a cash basis, no.

MR. FITZGERALD: Are the rates designed for accrual or cash?

MR. HAMILTON: The base rates are on a cash basis, well it's not really fair to say that either because the ... there are other elements in the revenue requirement from an accounting point of view that are accrual in nature and there's all kinds of deferred costs. I mean depreciation, for example, is a levelized deferred cost over time. You don't pay for the cost of generating plant the day it's built. It's interest expense and the depreciation, that's a deferral. That's also a levelized cost, if you will, over time, and in some ways then this is also in that nature. There is a deferral (inaudible) which is a liability or an asset.

MR. FITZGERALD: Turning then to the other criteria that Bond Bright has outlined and that you've adopted, and that is when you're designing rates, market efficiency is something to keep front and centre in mind. How does the RSP affect this criteria?

MR. HAMILTON: The RSP, by its nature, has a levelizing effect, and it also has a lag element in it so that there's, if the rate doesn't react immediately to a change in a cost of energy, so it gets dampened over time, so it would be a ... if the costs are going up (inaudible), therefore the customers will not see the real cost on the way up or on the way down. In the last several years it's been on the way up, so in that regard it is not pricing the energy at the current cost, so it would considered to be a negative in that regard.

MR. FITZGERALD: It's a negative, yeah. The third criteria that you've included or adopted of Bond Bright's, the cost based rates, how does the RSP impact on that?

MR. HAMILTON: I think the RSP in that regard is fair. The cost, the increased cost of thermal is being fairly allocated between the customers that have caused the increase in thermal cost, it's split between the industrials and the retail portions, so on that criteria it's fine.

MR. FITZGERALD: It's fine, does that mean it's a positive or a negative, or is it neutral?

MR. HAMILTON: I guess you'd call it positive because the costs are assigned to the appropriate class.

(10:45 a.m.)

MR. FITZGERALD: The fourth criterion outlined on page two is the concept of stability which has to be kept in mind when designing rates. Can you, again, describe how the RSP would impact on the stability of rates?

MR. HAMILTON: As I pointed out there are two aspects of the stability of rates. The aspect of generating a specific amount of revenue requirement in a stable manner, it's ... in that regard it's relatively stable because it only changes once a year, so the revenue that is set up, well it's calculated to recover in a subsequent period to pay for the allocated portion at the end of, say December in the case of the retail plan. In that regard it will pretty accurately recover that cost that it's designed to recover in the next period. It's also, in the second part of it, it doesn't, it changes once a year, not frequently, so it's relatively stable in that regard. The range of change compared to a customer's total bill, for the most part have been relatively stable, but at times when there's been rapid build up, it has probably resulted in more than a one percent increase on a customer's bill, but for the most part, I think, looking back over the years, that most of the times the RSP change has been for retail consumers anyway, one percent plus or minus a change in a bill from one year to the next. I think there might have been one or two occasions it was one and a half percent. I don't remember anything like four or five percent or anything like that, so in that regards it's fairly slow and so fairly stable as rate increases go.

MR. FITZGERALD: So of the two aspects that you've identified, one has a positive effect on one and a negative on another, or ...

MR. HAMILTON: They're both fairly positive in the, in the relative scale of a typical rate increase. If you have a full hearing, a typical rate increase would be usually two, or four, or five percent. I mean you don't generally have rate increases for small percentages.

MR. FITZGERALD: The fifth criterion which is on page two refers to administrative practicality and I'd ask you to identify, or I'd ask you to label the RSP as positive or negative when it comes to this particular criteria?

MR. HAMILTON: That one is a difficult one in terms of from which viewpoint it's being viewed.

MR. FITZGERALD: Well, I guess from the domestic consumer's point of view.

MR. HAMILTON: Well from the point of view of what he sees on his bill, it's ... he doesn't see anything on his bill. His bill goes up or down and there's a notice probably in his bill the month that that actually changes. In terms of his acceptance and level of understanding of what's in it, I guess most of the notices that I recall typically talk about fuel costs have increased or reduced and the balance is therefore moved, and in the nature of the recalculation, your bill has been increased by some percentage because of it, so to the extent that that's all you want to know, they're probably quite contented with that. In terms of the plan itself and the calculations of it, it is not something that is, that would be readily understood by a large portion of average consumers. I guess you could almost say they're going on blind faith that other people are making sure that it's done accurately, and the components of the plan are very straightforward mechanically and in a sense that the fuel cost calculation, the load calculation, the price calculation, they are fairly fairly stated so the mechanics, you can say that the customer would find it very complex, but then the calculation of any portion of the domestic rate, if you viewed it in that context, the mechanics of that, they wouldn't follow that either, so any aspect of rate derivation would be considered too complex for an average customer that hasn't been here for the time we've been here, for example. It's, so as I said, it depends on, in what relatively you're going at. Any portion of a rate in the design of it is not straightforward. For example, the cost of service guides the rate design for a domestic customer. To the extent that you got a simple number that comes out of it, you can say therefore it's fairly simple, but you've got to be able to appreciate the cost of service to get even the basic domestic rate, so in that context, compared to that process, the RSP is no more complicated than normal rate design. The, if you're talking about the industrial customers, they understand the elements of the rate design process more fully than an average domestic customer, in their context most of the RSP they'd probably follow and understand as covered in the monthly report. The use of the cost of service, that portion that is not shown every month, that would be probably viewed as being not clearly understood and so in that context you'd say it's not an administratively simple process. So it depends on how much you want to know, and how far you go one way or the other.

MR. FITZGERALD: Can we gauge then from the length of your answer that it is administratively impractical?

MR. HAMILTON: There's got to be an easier way, and I guess the average consumer, anything to them would be difficult.

MR. FITZGERALD: Okay, the, having regard to that and the, also the problem that you identified with cost based rates, or actually market efficiency, as a rate designer, does the Rate Stabilization Plan create difficulties for you when you're trying to do your job?

MR. HAMILTON: I'm not quite sure I understand that question.

MR. FITZGERALD: Okay, does it deviate, does the Rate Stabilization Plan make the application of James Bond Bright's criteria difficult?

MR. HAMILTON: The criteria that you have there, and these are the main ones that we were trying to base things on, quite often what you do in one aspect of a rate design is a positive in certain aspects and a negative in others, and the most you can try and do is optimize at the end, that the end product is as good as you can get and meet as much of the criteria as you want and the relative ranking of criteria depends on the respective person's viewpoint and a point in time, quite often, and I know some of my earliest courses I went on in rate design and stuff, that there used to be a favourite activity early on was to have the various people in the room rank Bond Bright's criteria, and you'd always see the rankings would be different relative to priorities, depending on the background of the person that was there, both in terms of was he from a ... as a consumer, as a regulator, or as a rate designer, how long they'd been in that activity, and also whatever local issues he brought with him when he came to the meetings, and you would, one person might rank them just as they are there, one to five ... another person would be exactly the opposite, and it would be all over the map, so the relative ranking of the criteria, it's a variable and you just aim at the end of the day to try and get things as good as you can.

MR. FITZGERALD: Mr. Chairman, I don't know if this might be a good place to break. I could advise the Board that I should only be about another half hour, if that, with Mr. Hamilton.

MR. NOSEWORTHY, CHAIRMAN: That's fine, we'll break until ...

MR. FITZGERALD: And Mr. Browne may be a half hour as well.

MR. NOSEWORTHY, CHAIRMAN: Thank you, we'll break until 10 after.

(break)

(11:15 a.m.)

MR. NOSEWORTHY, CHAIRMAN: Thank you. I'd ask Mr. Fitzgerald could you continue with your cross, please?

MR. FITZGERALD: Mr. Hamilton, I'd like to refer you to a report of this Board of 1990, a report on proposed rates to be charged to Newfoundland Light and Power. I don't believe it's part of the record, and there's an excerpt that I'd like to circulate now, actually, if I could.

MR. KENNEDY: That would be CA No. 3, Chair.

EXHIBIT CA-3 ENTERED

MR. FITZGERALD: Mr. Hamilton, page 51 of that report, the second paragraph there is a finding of the Board. I'm wondering if you could read that excerpt of this decision into the record, please?

MR. HAMILTON: Starting at the top of the page?

MR. FITZGERALD: The second paragraph.

MR. HAMILTON: Second paragraph. "NLP submitted that cost deferrals are against generally accepted utility practice of matching rates to costs in the period in which they occur and that cost deferrals should not be made, especially when they can be reasonably avoided."

MR. FITZGERALD: Okay, and do I understand, Mr.

Hamilton, that you were, in fact, an employee of Newfoundland Power in 1990?

MR. HAMILTON: Yes, I was.

MR. FITZGERALD: And can you indicate in what capacity you were employed at that time with Newfoundland Power?

MR. HAMILTON: At that time I was manager of rates and forecasts, I believe.

MR. FITZGERALD: Not too dissimilar from your current capacity with Hydro?

MR. HAMILTON: Well, the major difference would be back then I was ... I had line responsibilities and staff reporting to me. In 1990 I was ... whereas today mainly a staff position, but in the same general area, yes.

MR. FITZGERALD: The principle for the submission of Newfoundland Light and Power that was presented to this Board in 1990, as you've just read into the record, do you still subscribe to that principle?

MR. HAMILTON: This principle as stated here was referring to a specific cost?

MR. FITZGERALD: Well, I guess I would ask you the question. This clearly states that Newfoundland Light and Power submitted that cost deferrals are against generally accepted utility practice. I took that to mean universally.

MR. HAMILTON: The cost deferrals can result in problems with rate design in matching rates to costs in a period.

MR. FITZGERALD: Yes.

MR. HAMILTON: It depends on ... I'll try in the context this is here, I guess. There are different ... there are some costs that are appropriate to level over time, but I think this is probably some kind of ... the next paragraph talks about losses, so it's the extent that deferral results in mismatching of the timeframe it causes problems in rate design.

MR. FITZGERALD: Okay. Is that any different than from what the RSP does? Doesn't the RSP defer costs?

MR. HAMILTON: Yes, the RSP does defer costs or savings.

MR. FITZGERALD: Well then wouldn't that be against generally accepted utility practice of matching rates to costs?

MR. HAMILTON: It doesn't match rates to costs in the time period incurred, that's correct.

]MR. FITZGERALD: So does that offend or is that against generally accepted utility practice?

MR. HAMILTON: In that context, yes, it would be against generally accepted principles of matching costs.

MR. FITZGERALD: Thank you. Just going back briefly to page 2 of your testimony, again referring to Bond Bright's principles of sound rate structure and the five criterion that are displayed on that page. Does Hydro give specific emphasis to any of the rate design criteria listed there?

MR. HAMILTON: In general or at the point in time of this hearing? I'm not sure I understand the context of the question.

MR. FITZGERALD: Okay. I'll put it this way, and you can correct me if I'm wrong on this, but isn't it true that James Bond Bright attributes secondary importance to the criterion of stability?

MR. HAMILTON: He would indicate that there are certain criterion that he felt were more critical to ensure, stability would be one of the lesser ones in his eyes.

MR. FITZGERALD: Okay. In the customer surveys that Hydro has conducted, have you asked customers to rank stability in terms of importance when it comes to rates?

MR. HAMILTON: I'm not sure exactly the wording of the questions on the survey for customers in terms of ... I know they were asked rate questions, but I'm not sure exactly the wording of the questions, so I can't comment on that.

MR. FITZGERALD: So I guess then you wouldn't know whether customers have expressed a willingness to pay a premium for rate stability?

MR. HAMILTON: I couldn't say.

MR. FITZGERALD: I understand from Mr. Osmond's testimony that there is some consideration for what's called the fuel price hedging program, at least it's on the landscape?

MR. HAMILTON: That has been investigated.

MR. FITZGERALD: It has been discussed by Hydro?

MR. HAMILTON: Discussed and phantom hedges have been placed to try and test the mechanism and how it worked, that type of thing, yes.

MR. FITZGERALD: Has there been any consideration of surveying the customers as to whether they would be prepared to pay the cost of an oil hedging program?

MR. HAMILTON: I don't know if there have been discussions held on that. I have no involvement in the developing of the questions for the customer survey.

MR. FITZGERALD: Has Hydro ever considered offering customers the option of a fixed rate over a number of years as an option, a fixed rate, fixed rates?

MR. HAMILTON: I'm not sure I understand what you mean by fixed rate. You mean pay the same monthly amount?

MR. FITZGERALD: Yes.

MR. HAMILTON: In total?

MR. FITZGERALD: Uh hum.

MR. HAMILTON: Only from the point of view of an equal payment plan, levelizing the customers' bills based on their relative consumption. That's been discussed and the plan is to implement such a plan over the next ... in place by 2002, 2003 time period, if that's what you're asking about.

MR. FITZGERALD: If as a result of this hearing or for some other reason the RSP was either eliminated or altered in some form, has Hydro any contingency plan that would substitute the RSP?

MR. HAMILTON: If the Board were to ask to have the RSP replaced with some other mechanism then I guess it's been pointed out on the record by one or two witnesses, that a plan somewhat similar to what was in place before the RSP would be requested, a water equalization plan to handle fluctuations in the hydraulic production and a fuel adjustment clause to handle the variations in quantity of fuel or price variations, so that would be the, I guess, the offset to the RSP.

MR. FITZGERALD: And Hydro would be equipped to face the challenge like that in short order?

MR. HAMILTON: It would, depending on the plan, it would take some time to set up. How long it would take ... better measure it in weeks, maybe a month or two than it would be measured in days, I would think.

(11:30 a.m.)

MR. FITZGERALD: And if we could turn now to page 7 of your originally filed evidence, Mr. Hamilton. At lines 23 and 24, you've indicated there that Hydro will include rate changes for subsequent periods in the five-year plan to be submitted at Hydro's next rate hearing. I'd just like to know what the conditions were that precluded Hydro from submitting such a plan at this time?

MR. HAMILTON: This is in the context of the Labrador system, and given the wide range in rate structures that exist in Labrador right now, the primary concern was what the nature of the rate structures the Board felt would be appropriate while some of the rate categories are ... well, basically the rate categories we're proposing are the same as on the island, some of the structures themselves were not exactly the same, so rather than proposing a series of increases, I guess, or reductions, because it's both going on, that it was felt appropriate to first get concurrence from the Board that the long-term direction as outlined in my Schedule 3, I believe it was, that they agree with that target, so that if they approved the rates as proposed right now and accept this rate structure then we can clearly put together and plan for it, but if they don't feel it is an appropriate structure then developing a multi-year plan would be going in the wrong direction and so therefore I just ... the important part at this juncture was to get concurrence that indeed a uniform rate for Labrador was approved and that the final set of rates would be ... that this was an appropriate rate structure for them, and until we get that guidance we just felt it would be more confusing to have a myriad of possible plans there.

MR. FITZGERALD: Okay. Mr. Hamilton, if you can turn then to page 12 of your pre-filed evidence? Line 17 to 19 you're referring to Mr. Brickhill's evidence. You say, line 17, "As outlined in Mr. Brickhill's evidence, revenue from secondary sales in Labrador has been credited in the COS study to the other regulated rate classes on the Labrador interconnected system." Can you briefly describe on what basis that was met?

MR. HAMILTON: Well, the revenue was credited as opposed to ... because it's a secondary rate the bulk of the ... well, basically, the full cost of the system is covered by the firm load customers, and therefore there's not a lot of direct cost associated with those sales, and therefore there is by nature of the rate proposed, there is a substantial amount of revenue in excess of the incremental cost, so the typical treatment would be to recognize that in a test year and to then credit the extra revenue back to the benefit of the firm customers.

MR. FITZGERALD: Okay, and is this consistent with the treatment of revenues from non-firm sales in other systems?

MR. HAMILTON: Yes. On the island we also ... the non-firm sales from industrial customers and ... you know, I guess it's only non-firm sales. They are credited back in the island interconnected cost study.

MR. FITZGERALD: Page 15, Mr. Hamilton, of your originally filed evidence. Here you're addressing transformer discounts. You indicated here, in the Labrador interconnected system transformer ownership discounts for the Labrador interconnected system are 25 cents and 60 cents per kVa for primary and transmission supply respectively while in other areas they are 40 cents and 9 cents per KVA. Why do the discounts in Labrador vary from those in other areas?

MR. HAMILTON: We're proposing a lower level in Labrador because the costs in the system up there are lower than on the island.

MR. FITZGERALD: Sorry, the cost of the transformers?

MR. HAMILTON: The embedded costs on the system are somewhat lower resulting in lower demand costs on the Labrador system versus on the island. On the island we're matching Newfoundland Power's transformer discounts, 40 cents to 90 cents. I'm not sure of the exact basis for those numbers, but presumably it's relative to their overall costs on the island, and the unit costs in Labrador are a fair bit lower, and as you see on Schedule 3 the proposed demand charges in the long term are a third to a quarter of the demand charges that'll be on the island, so we felt then a transformer ownership discount has to bear some relationship to the demand charge that would apply in Labrador. It's not a direct proration that's there.

MR. FITZGERALD: Also I'd like to direct you, now, Mr. Hamilton ... Mr. O'Rielly, if I could have **CA-70** on the screen, please, page 2 of 3? And really, Mr. Hamilton, for confirmation purposes this particular chart, is this an accepted way of gagging the level of cross-subsidization among customer classes?

MR. HAMILTON: The table shows the unit rates and the last columns it shows revenue cost ratio. Is it the last two columns you're referring to?

MR. FITZGERALD: Yes.

MR. HAMILTON: Revenue cost ratio, which show basically the relative revenue compared to the actual cost incurred in serving that customer class, so therefore, yes, it does provide an element of the interclass subsidization that would occur. There's also within the class, there's also some subsidization between different usage profiles, but this would be the interclass.

MR. FITZGERALD: Okay, and so these figures then when we're trying to figure out in layman's terms who's paying for what, who's paying more, who's paying less out of the cost of service, this **CA-70** provides us a guideline?

MR. HAMILTON: It does for most. The ones that probably are distorted would be ... or would distort it most would be Newfoundland Power because the cost that's already in there includes the deficit assigned to them, I believe, for the purpose of that ratio calculation I'm not sure, but the rest are pure cost versus the revenue right now.

MR. FITZGERALD: Okay, so just looking at line 1 then say, on the island interconnected Newfoundland Power, we see the current revenue of 1.05, that means what?

MR. HAMILTON: Their revenue pays five percent over their direct cost of service.

MR. FITZGERALD: Okay, so if you're paying over one on that chart you are subsidizing?

MR. HAMILTON: Yes.

MR. FITZGERALD: If you were paying less than ... or if you were indicated less than one on the chart you are being subsidized?

MR. HAMILTON: That's correct, yes.

MR. FITZGERALD: Okay. Thank you, Mr. Chairman. I think Mr. Browne now has some questions.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Fitzgerald.

(11:45 a.m.)

MR. BROWNE, Q.C.: Thank you, Mr. Hamilton. Can we go to **CA No. 1**? It's not **CA-1**, I think we've labelled **CA No. 1** as the back of the bill that we were using when we were up on the coast of Labrador dealing with kilowatt usage, and we have it on the screen there for those who are looking for their hard copy. The design of this bill, does that fall within your bailiwick, Mr. Hamilton?

MR. HAMILTON: No, it doesn't.

MR. BROWNE, Q.C.: But what about the kilowatt usages that are there, would you be familiar with those?

MR. HAMILTON: What, involved in developing those quantities?

MR. BROWNE, Q.C.: Yes.

MR. HAMILTON: No, I wasn't, no.

MR. BROWNE, Q.C.: But are you familiar with them, can you speak to them at all? As a rate design person do you know that water heating on average for a typical family of four has a usage of 500 kilowatt hours for that particular unit, are you aware of that?

MR. HAMILTON: Yeah. The quantities there are in the range of numbers that I've seen, yes.

MR. BROWNE, Q.C.: Okay, so you've seen them?

MR. HAMILTON: Yes.

MR. BROWNE, Q.C.: You don't make any mention of electric heat here for a typical family of four using electric heat. Is there any particular reason for that?

MR. HAMILTON: Electric heat usage varies with, very much, the, not just the number of people but the size of the house and the location of the house and the type of insulation that's in it. You can have two houses almost identical to look at from the outside and their electric heat consumption would be literally a ratio of two to one, just in the same town. People want different comfort levels, type of insulation ...

MR. BROWNE, Q.C.: So you can't give a typical family as you can for these other usages here?

MR. HAMILTON: Not really, no. The range would be very wide.

MR. BROWNE, Q.C.: If you don't design this, who does? Who's responsible for designing the back of the bill, giving customers information, whose department is that?

MR. HAMILTON: That's within the customer service area, would be a different group of ... in it, but the consumption numbers ...

MR. BROWNE, Q.C.: Excuse me, can you speak up a little, please? I'm having some difficulty here.

MR. HAMILTON: Okay. The different grouping within the customer service area.

MR. BROWNE, Q.C.: But it's within your department, the department you work in?

MR. HAMILTON: It's within the department, yes.

MR. BROWNE, Q.C.: When we were up on the coast of Labrador people spoke to these particular usages and they were on a lifeline rate of 700. Are you familiar with that lifeline rate?

MR. HAMILTON: Yes.

MR. BROWNE, Q.C.: Well, if the lifeline ... do you know the way the lifeline rate was devised or developed, are you familiar with that?

MR. HAMILTON: It has evolved over time. Originally when it came in it was 500, it got increased to 600 and I believe 1990 it was increased to 700. There was never a, that I'm aware of, there's never been a calculation presented that showed the basis for the number.

MR. BROWNE, Q.C.: But you would agree that you're promoting here for the ... during a winter month, and on the coast of Labrador we know the winters are long, someone mentioned they could be all of six months, that the monthly usage without electric heat there could be 1156?

MR. HAMILTON: That's correct.

MR. BROWNE, Q.C.: So is the lifeline rate of 700 adequate for people living in rural areas, particularly in the coast of Labrador?

MR. HAMILTON: In a winter month, extensive usage, 1156 would clearly be above the 700 kilowatt hour level that's indicated there. I believe the average monthly consumption of customers in the isolated areas comes out to about 700. That means, I guess, they have bills above 700 and bills below 700. This would be, as pointed out, typical at a point in time during the winter, so there'd be months during the year it'd be less than that, presumably. The lifeline concept is, in theory, I guess, is always to provide a level of energy use that will meet consumers' essential needs. Some might question if there's an alternative energy source available to customers does that require an allowance in the lifeline block. I believe back in ... the last time it was increased from 600 to 700 the main issue at that time was whether or not to include hot water heating and to what extent, because hot water heating can be oil fired or wood fired hot water and ...

MR. BROWNE, Q.C.: And realistically on the coast of Labrador can ... how many people have their oil supply up there to have an oil fired hot water boiler?

MR. HAMILTON: Very few do. Again, I guess, the question becomes then is that ... whose choice is it or is it a ... does the consumer have any control over that or not, and I can't speak to that, but, I just know that you can have oil fired hot water tanks, they do in the city. I know back in 1990 St. Anthony indicated that there's a problem with having hot water tanks oil fired, serviced or whatever, so if that's a constraint ... but that would be the biggest difference between the 1156 and the 700 level, whether or not you allow for electric hot water. If you assume electric hot water ...

MR. BROWNE, Q.C.: But you're admitting to me most people along the coast of Labrador would have electric hot water because the oil supply isn't there for them?

MR. HAMILTON: I understand an oil fired hot water system is more expensive because of the price of the oil, and therefore, they don't have oil fired hot water tanks. I don't ...

MR. BROWNE, Q.C.: And they don't have oil furnaces?

MR. HAMILTON: A lot of them don't, but again, I'm not sure if that's their choice or subject to the geography, I don't know, and that's why I say, to get back to the level of the 700, what should it reflect, what's within their purview. Lighting, obviously, would be electricity, but their heating system for water and their house may have some flexibility there, so should that be covered in the lifeline block, that's a judgment question.

MR. BROWNE, Q.C.: But you would admit, on its face, someone getting this bill up on the coast of Labrador opens a bill and looks to the back of it and says, you know, typical monthly amount I need, according to Newfoundland Power ... according to Newfoundland Hydro, is 1156 during a winter month, and they don't have electric heat so presumably even summer variations would be taken into account here, might say I'm not getting what's adequately required for my lifeline?

MR. HAMILTON: If they have those quantities that's right, it's not enough there. The question then just is does a hot water tank constitute ... should be included in a lifeline rate, and if a hot water tank, full usage of a hot water tank should be included in the lifeline, then the 700 will not cover it.

MR. BROWNE, Q.C.: But you grant ... so therefore, you grant me that they may need some variation upward from the 700 lifeline rate in some coastal and the coastal areas of Labrador in particular?

MR. HAMILTON: If it's felt appropriate that hot water tanks be subsidized significantly, that's, I guess, the Board would have to make that judgment.

MR. BROWNE, Q.C.: I noticed the back of your bill is designed in a particular fashion. I just want to show you the back of Newfoundland Power's bill and put some questions to you in reference to that. I gather you're a customer of Newfoundland Power?

MR. HAMILTON: Yes, I am.

MR. BROWNE, Q.C.: So you get your bill like the rest of us?

MR. HAMILTON: Yes.

MR. BROWNE, Q.C.: In urban areas, okay.

MR. KENNEDY: That would be CA No. 4, Chair.

EXHIBIT CA-4 ENTERED

MR. BROWNE, Q.C.: Okay, I think that's been distributed. Now, if we do a comparison of **CA 1** and **CA 4** Hydro's, the back of Hydro's bill and the back of Power's bill they're both into the meter reading game there. Is it your experience that consumers use that portion of the bill?

MR. HAMILTON: I believe some consumers do use it for inaccessible meters. (inaudible)

MR. BROWNE, Q.C.: Have you tested that in any of your surveys to make that determination, if that is being used or that is useful information for consumers?

MR. HAMILTON: I don't think there's questioning on it. I'm not aware there would be any questions on it in the survey, I don't know.

MR. BROWNE, Q.C.: I notice that on your particular bill you do give various kilowatt hours for particular usages which Ms. Pauly from the Federal Energuide Program, described as useful information for consumers, but I note that Newfoundland Power gives no such information. Why are you providing the guide, are you providing the guide so it could be helpful for consumers, the listing of usages here?

MR. HAMILTON: Yes, the people that designed the bill felt it would be useful to customers, yeah.

MR. BROWNE, Q.C.: And some of your bills are based on Newfoundland Power's rates, aren't they?

MR. HAMILTON: Yes.

MR. BROWNE, Q.C.: Yes, so some consumers who are getting billed on Newfoundland Power's rates gets some information concerning kilowatt hours and others who are billed on Newfoundland Power's rates are getting no such information. Is that what you would conclude there?

MR. HAMILTON: Yes, there's no information on the back of the Newfoundland Power bill, no.

MR. BROWNE, Q.C.: Sure. Nowhere in your bill or either bill do you define what a kilowatt is. Is that anywhere to be seen there?

MR. HAMILTON: No, not that I can see.

MR. BROWNE, Q.C.: Nowhere in your bills do you advise or give a regular advisory to consumers to get rid of their clunkers. I think Ms. Pauly, when she was here, said there's a real problem as people replace their refrigerators for one that's standardized by the Federal Energuide Program. They ... a lot of people continue to put their clunkers down in the basement and use them, which is something, it's not helpful to kilowatt usage. Were you here to hear her say that?

MR. HAMILTON: No, I wasn't here to hear her say that, but yes ...

MR. BROWNE, Q.C.: Does it surprise you?

MR. HAMILTON: No. I know some relations of mine that have done that.

MR. BROWNE, Q.C.: And just by advising consumers things to avoid, wouldn't that be helpful information to put on a bill?

MR. HAMILTON: I guess it could be useful to customers. I assume that people, when they design a bill, there'd be trade off between what they can or can't get on there. It's always a trade off what's more or less useful, and the people that designed our bill made certain judgments and Newfoundland Power made certain judgments, but ...

MR. BROWNE, Q.C.: Have you ever thought of getting together and designing the one bill for consumers across the province, would that be injurious to either one of you?

MR. HAMILTON: No, it wouldn't be.

MR. BROWNE, Q.C.: And it might be helpful to consumers. Or if you did a survey to find out what consumers would like to have on their bill or what might be useful, such as what Ms. Pauly said concerning your own bill, the information concerning kilowatt usage, you haven't ... there's no talk of that, is there?

MR. HAMILTON: (inaudible) questions on the surveys, but the people that would be involved in the designing of the bill are in the customer service area. They would be people that have dealt with customers and explained their bills, any inquires they had on their bills for increases, or whatever nature, so presumably then they would draw on the experience gained from dealing with customers through the inquiries to identify what typical things are asked and then provide that type of information on the bill within the limitations of what the bill can fit.

MR. BROWNE, Q.C.: Now, Newfoundland Power in its bill describes the equal payment plan. Can you read that into the record, sir?

MR. HAMILTON: "Equal payment plan. Choose from a 10 or 12 month equal payment plan. Our 10 month plan allows you to spread your electric service charges over 10 months with no electric payment due on your July and August bill. The 12 month plan spreads your electric service charges over 12 months."

MR. BROWNE, Q.C.: Okay, so even within the equal payment plan that Newfoundland Power promotes there are choices of a 10 month or 12 month payment that people can opt into?

MR. HAMILTON: That's correct.

MR. BROWNE, Q.C.: And to your knowledge, does the equal payment plan that you people are about to embark upon offer in the same options?

MR. HAMILTON: I'm not aware of what they've decided to include for options in the plan yet. I think it's still very much in the developmental stages, so that decision hasn't been made yet, as far as I know.

MR. BROWNE, Q.C.: Are you familiar with the concept of rate shock?

MR. HAMILTON: Yes.

MR. BROWNE, Q.C.: And what is rate shock, can you define rate shock for us?

MR. HAMILTON: Rate shock would be a, I guess, defined as a sudden increase in the rate charged.

MR. BROWNE, Q.C.: A sudden increase in the rate charged?

MR. HAMILTON: Sudden, I guess, large increase, right.

MR. BROWNE, Q.C.: And how do companies, such as your own view rate shock, is it a desirable thing or is it something that they tend to avoid?

MR. HAMILTON: You try to avoid it to the extent that you can control it.

MR. BROWNE, Q.C.: And do you know or have any idea as to how companies sometimes deal with rate shock, how do they try to avoid it, what programs do they put in place to avoid it?

MR. HAMILTON: Typically you would try to levelize some of the costs or defer some costs, to the extent that you can, to wrap up, if you would, for the ... rather than have a sudden increase.

MR. BROWNE, Q.C.: Yeah. I just want to give you an excerpt from the 1990 hearing when reference was made by your former Chief Executive Officer to rate shock. Can we distribute this, please? And the 1990 report is not available, I understand, Mr. O'Rielly. Thank you.

MR. KENNEDY: CA No. 5, Chair.

EXHIBIT CA-5 ENTERED

MR. BROWNE, Q.C.: And on page 44 under the heading "Deferral of Cost", Mr. Avery, and who is Mr. Avery, Mr. Hamilton?

MR. HAMILTON: He was the CEO at Newfoundland Hydro.

MR. BROWNE, Q.C.: Just can you read into the record the first to paragraphs there, please?

MR. HAMILTON: "Mr. Avery testified that in order to phase in the extra costs incurred following last year's budget and avoid a sudden rate shock Hydro is proposing to spread these additional costs over a period of eight years. This will be accomplished by deferring some costs each year and amortizing them over the subsequent five years. For the next three years Hydro is proposing that the rate charged NLP increase by eight percent per annum which will result in a domestic rate increase of approximately 4.5 percent per year, exclusive of any Rate Stabilization Plan adjustments. This will basically match the rate of inflation anticipated so the impact on individual consumers will be more manageable."

MR. BROWNE, Q.C.: Okay, so I guess that gives one of the options that Hydro has looked at in the past in order to avoid rate shock. Is that a fair comment?

MR. HAMILTON: That's an option that was proposed back in 1990, yes.

MR. BROWNE, Q.C.: Sure.

MR. HAMILTON: Uh hum.

MR. BROWNE, Q.C.: Because you're aware of the evidence before this Board that in reference to the Rate Stabilization Plan, which is approaching the $100 million mark, that Hydro has given no options to the Public Utilities Board, other than to increase the cap from $50 million to $100 million, you're aware of that?

MR. HAMILTON: I'm not sure it's in the same context, but because the ...

MR. BROWNE, Q.C.: Well, you don't have to explain it. Are you aware that Hydro is proposing to go from 50 million to 100 million?

MR. HAMILTON: Yes.

(12:00 noon)

MR. BROWNE, Q.C.: Yes, you're aware of that, okay, so if the Board, in its wisdom, decided that that would not be prudent or appropriate to increase that cap, is it not possible, in order to avoid rate shock, for Hydro to do what Mr. Avery suggested here, to view these costs in the Rate Stabilization Plan, which are appearing more confused as we get along, as sort of stranded costs of some sort and to order a fix be put on them and that they do as Mr. Avery suggested here, spread them out over time and ease the burden for consumers? Would that not be an option? I notice Ms. Greene is shaking her head there. I assume she doesn't agree.

MS. GREENE, Q.C.: That's because the context of what Mr. Browne is referring to from the `90 report was totally different. It addressed the deficits that had been accumulated to date as opposed to an ongoing cost for fuel, so it's not an apples to apples comparison.

MR. BROWNE, Q.C.: Okay. Thank you, but in any case, is that not an option, is that not an option that Hydro put before the Public Utilities Board in reference to deferral of costs in 1990? You would have to say yes, would you not?

MR. HAMILTON: It's an option, and I guess the RSP it does level it out over a period of time. It's a case of do you levelize the RSP over three years by declining balance or take a portion out and have the balance in. Some amounts in the RSP that amortized for a one time period, another portion of the cost amortized over a different time period, but the RSP already amortizes it over a time period.

MR. BROWNE, Q.C.: Now, the RSP, the principle behind the RSP is that if there was money in the account, if there was a surplus, that money would go back to consumers. Wasn't that the principle behind it?

MR. HAMILTON: Yes, if it was surplus it'd be credited back to customers and if it's a deficit then it's charged to customers.

MR. BROWNE, Q.C.: Now, has that always been the case, if there was a surplus it's gone back to consumers, to your knowledge?

MR. HAMILTON: Yes.

MR. BROWNE, Q.C.: Can you just go to page 54 of this excerpt I just gave you? And page 54 has a conclusion there, the Public Utilities Board. Can you read that into the record for us, please?

MR. HAMILTON: The Board believes that using part of the balance of the estimated $19 million in the RSP owing to ratepayers as of June 30th, 1990, to offset the $8.941 million loss for PDD from April 1, 1989, to December 31, 1989, will not impinge on the integrity of the RSP and is the most suitable way of dealing with the unforseen loss of the government subsidy. The Board makes this recommendation.

MR. BROWNE, Q.C.: So I guess if there's money lying around it's no guarantee that it will go directly back to consumers. Is that one of the conclusions you would come to, having read that?

MR. HAMILTON: I guess the Board chose to use the balance to offset the loss, I guess, depends on what the alternative way to recover the loss, who was going to pay for that.

MR. BROWNE, Q.C.: But that wasn't the principle of the RSP, was it? The principle of the RSP was if there was a balance in it, we were told it would go back to consumers. And here we see where there was a surplus, albeit there hasn't been very times there has been a surplus, where the Board, in its wisdom, decided to take that, a portion of that, and to use it to defray a cost?

MR. HAMILTON: I guess the question is would the cost have been passed on to consumers and therefore it's a net effect and therefore customers still got the benefit of the money that was in the RSP.

MR. BROWNE, Q.C.: And do you know if consumers were ever advised that their money was used for this purpose or ever consulted or given a handout in their bills or any of the above?

MR. HAMILTON: I don't know.

MR. BROWNE, Q.C.: Now, that was 1990, via 1990. Can you just go to **CA-216** for a moment, please? And we see there in **CA-216** the Rate Stabilization Plan, as expressed in millions, and the balance due from or to consumers as put forward by Newfoundland Power and our information request. That $19 million that the Board used there to offset an expense out of the RSP, would that have come from 1989, does it look to you as that would be the years it would come from, the $19 million and there's a surplus in the account?

MR. HAMILTON: Yes, it would be the ... it looks like it's `89, given the timeframe that was discussed in the Board's report. It would come from that $31 million or $32.8 million from the balance.

MR. BROWNE, Q.C.: And do you recall the Board, what it set the rate at in the RSP, the rate for a barrel of oil in 1990, any idea of that?

MR. HAMILTON: No, I don't remember. I'm thinking it's ... it's too far ago to try to remember. Is that 30 or 18?

MR. BROWNE, Q.C.: Does $18 sound right?

MR. HAMILTON: Yeah. It's either 30 or 18. I can't remember back in the ... it was originally set at $30 back in 1985 and then it went down to 18 in 1990 and then down to $12.50 in `92.

MR. BROWNE, Q.C.: Okay. I'll just read to you from the excerpt of the 1990 case, page 40. I don't have it to hand out. "Hydro is proposing the price of Bunker C oil be maintained at $18 for the 1990 cost of service increase to $20 in 1991 and $21 for 1992." Do you recall ... you were present at that hearing. Do you recall that Hydro actually proposed a variation in the rates over a number of years in that particular hearing, have you any recollection of that?

MR. HAMILTON: Yes. That particular hearing they had a series of three test years.

MR. BROWNE, Q.C.: And do you recall what the outcome was from the Board's perspective, if they accepted that to increase the price of Bunker C oil to $18 for 1990, $20 to 1991 and $21 to 1992?

MR. HAMILTON: The Board only went with the one test year.

MR. BROWNE, Q.C.: And therefore, they accepted the $18, I think. Is that your recollection?

MR. HAMILTON: Yes, $18 was used.

MR. BROWNE, Q.C.: So going into ... and what did it come down from then sir?

MR. HAMILTON: Oil prices varied up and down.

MR. BROWNE, Q.C.: Was it $30, the price?

MR. HAMILTON: Back when it originally set up it was $30.

MR. BROWNE, Q.C.: So it's $30, then it went to 18?

MR. HAMILTON: Yes. The RSP.

MR. BROWNE, Q.C.: Yes, and although you were suggesting $21 for 1992, do you know what actually happened in 1992, what was it set at in 1992?

MR. HAMILTON: 1992 it was set at $12.50.

MR. BROWNE, Q.C.: And do you know if that was the recommendation of Hydro in 1992, to set the rate at $12.50?

MR. HAMILTON: No. I believe the proposal was 14 or $14.50 a barrel.

MR. BROWNE, Q.C.: Yeah, I think you're right there. We can go to the 1992 report, Mr. O'Rielly, and if you go to page 69, please? And under the heading Oil Prices, can you read that for us, into the record, please?

MR. HAMILTON: "Hydro's cost of service for the 1992 test year used as its forecast price of Bunker C oil, $14 per barrel. In response to **NP-48** Hydro explained that fuel price forecasts stems from projection of world oil prices and particular characteristics of the residual fuel oil market. While blended fuel price was $13.99 per barrel, as at December 1991, **NP-83**, **NP-14** disclosed December, 1991 price of Bunker C as $12.50. The price of Bunker C has continued to fall. During cross-examination Mr. Dave Collett of Hydro, estimated the price of Bunker C residual at about $10 per barrel. Page 320 of the transcript. Hydro states in its final argument, pages 21 and 22, that $14 per barrel forecast is most representative of the forecast cost for the 1992 test year. The current price at the date of the final cost of service would not produce any better forecast for the test period, in Hydro's opinion. Any deviation between forecast and actual are taken into account in the RSP."

MR. BROWNE, Q.C.: Okay, and then on page 70 I think it goes to discuss other positions, but If you just go to page 71 for a moment, we'll just get to the nub of it, and on the top of page 71, just the paragraph before Conclusion there, "The Board must also consider," can you read that for us, please?

MR. HAMILTON: "The Board also must consider the cost value placed on oil inventory at December, 1991 was approximately $14 blended cost. Therefore, all matters considered, the Board believes a forecast price of $12.50 per barrel would reflect the lower current price during the hearing, as well as an adjustment for the higher cost of opening inventory at the beginning of the test year."

MR. BROWNE, Q.C.: And the recommendation?

MR. HAMILTON: "Conclusion. The Board recommends that the purchase price of Bunker C oil, used for the purposes of the RSP and in the calculation of Hydro's fuel expenses, be dropped from the current $18 per barrel to $12.50 per barrel with effect from January 1, 1992."

MR. BROWNE, Q.C.: Now, your recommendation to the Board, Hydro's recommendation in the 1990 hearing was that Bunker C for 1992 be at $21 a barrel as part of the three tier price that you were suggesting at that time. Do you recall that?

MR. HAMILTON: Not in detail, no.

MR. BROWNE, Q.C.: Okay. Well, maybe I'll undertake, during the lunch period, to put in the excepts from page 40 of the 1990 study, but it's there as fact that you were proposing $21 for 1992. Then in the 1992 hearing you proposed $14, ended up with $12.50. Now, can you go, for a moment, to **IC-22**? And in **IC-22** you were asked to provide the average cost in U.S. dollars of No. 6 fuel in each of the years 1992 to 2001, inclusive. "Please refer to the following table." So in 1992, if you look at it in Canadian dollars and recording Canadian dollars throughout, the average price was $14.29, that's correct?

MR. HAMILTON: That's what the table says, yes.

(12:15 p.m.)

MR. BROWNE, Q.C.: So your forecasting was a bit better than the Board's decision. You suggested $14 a barrel for 1992 and the Board came up with $12.50. Is that correct?

MR. HAMILTON: The Board recommended $12.50, yes.

MR. BROWNE, Q.C.: Now, if you look down through the column, from 1992 to 2001 where we are today, where do you see $12.50?

MR. HAMILTON: It's not there.

MR. BROWNE, Q.C.: It never reached $12.50, did it?

MR. HAMILTON: Not on an annual basis. There were points in time when shipments were bought for $12.50 or less, but on average for a given year it didn't get that low.

MR. BROWNE, Q.C.: And that's what we're talking about when you put your proposals to the Board, isn't it?

MR. HAMILTON: The average cost for the year, yes.

MR. BROWNE, Q.C.: Yes, and at what point, knowing that the price of a barrel of oil was set at $12.50, did you notice in your department and your dealing with rates, did it come to your attention that the fund was getting underfunded because you never were at $12.50 for the entire period from 1992 to 2001, when did that first come to your attention?

MR. HAMILTON: The balance was seen to be growing. The Rate Stabilization Plan has three factors in it, and so while oil prices were rising the quantity was below the forecast and that's one of the advantages of having three components in there, that for many years they're offsetting reductions, and so the balance did not grow as quickly as those numbers would make you think it would grow, because they're offsetting reductions.

MR. BROWNE, Q.C.: Would another complicating factor be the fall in the Canadian dollar, did that ever come to your attention?

MR. HAMILTON: These numbers here would also show ... are impacted by the exchange rate changes, yes.

MR. BROWNE, Q.C.: Because in 1992 we weren't dealing with a 60 cent dollar, were we?

MR. HAMILTON: I don't believe so no.

MR. BROWNE, Q.C.: But we're dealing with it today?

MR. HAMILTON: Pretty close to it, yes.

MR. BROWNE, Q.C.: And have you looked at any forecast in reference to the dollar and the exchange rate recently?

MR. HAMILTON: The last forecast I looked at projected the exchange rate to improve in the future.

MR. BROWNE, Q.C.: It would improve?

MR. HAMILTON: Yes.

MR. BROWNE, Q.C.: Is anyone suggesting a 70 cent dollar again?

MR. HAMILTON: I don't think the forecast went out that far.

MR. BROWNE, Q.C.: And there are other forecasters who are stating that there could very well be a 50 cent dollar, is that not true, have you heard that in the news?

MR. HAMILTON: I haven't seen a forecast that low, but certainly there's a wide range in forecasts.

MR. BROWNE, Q.C.: But you will agree with me that that has become a complicating factor in your purchase of fuel, the fluctuation downward in the Canadian dollar, the fact that we're now dealing with a 60 cent dollar?

MR. HAMILTON: Exchange rate has certainly added increased costs to us right now.

MR. BROWNE, Q.C.: So we have the fluctuation in the dollar, we don't know what the price of oil will be from year to year, do we?

MR. HAMILTON: We can't control that, no.

MR. BROWNE, Q.C.: No, you can't control that. You can't control your hydrology, can you, because you don't know what the forecast is going to be from year to year, do you?

MR. HAMILTON: We don't know what ... how much rain you're going to get, no.

MR. BROWNE, Q.C.: So these three factors are what contribute to the Rate Stabilization Plan, whether it's in a positive balance or in a negative balance, doesn't it?

MR. HAMILTON: That's correct.

MR. BROWNE, Q.C.: And all of them are variables, aren't they?

MR. HAMILTON: That is correct.

MR. BROWNE, Q.C.: So how can that plan lead to any form of stability when you're dealing with such variables, how can you refer to that plan as being stable?

MR. HAMILTON: By using averages, normals, numbers sort of in the midpoint ranges, that then the fluctuations above and below over a time period will average out, that hopefully on occasion that some will move positive, some will move negative and offset each other. Worse case scenario, they all move in the wrong direction and you have a large balance, as in right now, sometimes they all go in the other direction and you have a different balance.

MR. BROWNE, Q.C.: But you will admit to me that nothing has been in a positive balance since 1994, according to **CA-216**? If you go to **CA-216**, please, Mr. O'Rielly?

MR. HAMILTON: The combination of the components has left a balance in the monies owing from the consumers, but within those three components some elements were reducing the balance while others were increasing the balance.

MR. BROWNE, Q.C.: So in 1994, my question was, that was the last time we saw a positive balance, is that not true?

MR. HAMILTON: That is true, that's the last time the total plan was monies owing to consumers.

MR. BROWNE, Q.C.: And when the plan was put forward it was anticipated that there would be positive balances there, it would be fluctuating, one year negative, the next year positive?

MR. HAMILTON: Certainly they would fluctuate over a period of time, positives and negatives and ... yeah, it wouldn't be necessarily from one year to the next positive and negative, but over a period of time that it would average out.

MR. BROWNE, Q.C.: And what we're left with today, therefore, is the prospect of $100 million owing, and when do you see a positive balance now coming, can you forecast that for us, when will we see the next positive balance in the Rate Stabilization Plan?

MR. HAMILTON: The positive balance hasn't been in the forecast time period. I think the furthest out is 2004, I think the projection has been done. All those balances are assuming, however, when you project out, that all the forecasts, those, the forecast weather, that everything is exactly as forecast.

MR. BROWNE, Q.C.: So if we luck out and everything mixes together, the dollar, the price of oil, the forecast, if everything works out perfectly and after we get the debt paid that's in there, the 100 million, you're saying somewhere down the road we could see a positive balance, is that what you're telling us?

MR. HAMILTON: Could be sooner or later.

MR. BROWNE, Q.C.: Sooner or later?

MR. HAMILTON: Depends on how accurate the forecasts are.

MR. BROWNE, Q.C.: Thank you, very much, Mr. Hamilton, these are our questions.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Browne. Thank you, Mr. Hamilton. We will break now until 2:00 and we'll return with counsel's questions.

(break)

(2:00 p.m.)

MR. NOSEWORTHY, CHAIRMAN: Thank you and good afternoon. Before you start, Mr. Kennedy, are there any preliminary matters?

MR. KENNEDY: I don't believe so, Chair, not this morning, or this afternoon.

MR. BROWNE, Q.C.: I have ...

MR. KENNEDY: Oh, I beg your pardon.

MR. BROWNE, Q.C.: I undertook to provide the excerpt I referenced this morning in my cross-examination of Mr. Hamilton, so I can give that out. It's the 1990 Board decision page 40, and the reference I made was to the Hydro's proposal for the price of Bunker C fuel being a three-tier proposal.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Browne. Do you need to ...

MR. KENNEDY: Yes. An undertaking, I guess we should call it U-CA No. 1.

<u>EXHIBIT U-CA NO. 1 ENTERED</u>

MR. YOUNG: Mr. Chair, we traditionally make an announcement about this time about undertakings, and just for the record there really weren't any yesterday other than the one which Mr. Hamilton dealt with first thing this morning related to a number (phonetic) clarification, so.

MR. NOSEWORTHY, CHAIRMAN: Thank you. Sorry, what was the ...

MR. KENNEDY: U-CA No. 1, Chair.

MR. NOSEWORTHY, CHAIRMAN: U-CA No. 1. Thank you, Mr. Kennedy. When you're ready.

MR. KENNEDY: Thank you, Chair. Mr. Hamilton ... I wonder, Mr. O'Rielly, if we could turn to **CA-70**, the exhibit that the Consumer Advocate had up on the screen?

MR. O'RIELLY: 70?

MR. KENNEDY: CA-70, yes, 70, 7-0, page two. Actually if you'd go to page three first. Mr. Hamilton, I just want to see if I understood this document first. Is this sort of a before and after document? Page three is before the rural deficit allocation, page two is after the rural deficit allocation? If you could just toggle (phonetic) to page two, Mr. O'Rielly.

MR. HAMILTON: Table 2, or page two, which is Table 1, that's the existing rates and proposed rates consistent with the overall proposal and the way the deficit is currently being dealt with. Page three, if memory serves me, is to assume the deficit is not re-allocated.

MR. KENNEDY: Right. So as if they were paying the full shot, so to speak, that would be Table 2 on page three.

MR. HAMILTON: Yes.

MR. KENNEDY: Okay. And then after the rural deficit is accounted for for each of the customer groups, the resulting recoveries or revenue cost ratios are as revealed on Table 1 at page two.

MR. HAMILTON: That's correct.

MR. KENNEDY: The one I wanted to look at actually, if we could go to page two, Mr. O'Rielly, and towards the bottom of page two, and just looking at that for a second, CFB Goose Bay secondary, and the revenue to cost ratio for CFB Goose Bay secondary is showing on this table as being 21.61 or 21.61 times the actual cost to supply energy to CFB pursuant to the cost of service study, correct?

MR. HAMILTON: That's correct.

MR. KENNEDY: And I think that number was subsequently revised in **JAB-1, Revision 2, page 3 of 94**, to come in somewhere around 24 times as opposed to the stated number here of 21.61 times.

MR. HAMILTON: Yes. In the subsequent revision the fuel price forecast had gone up so that increased the rate to them and therefore increased the revenue plus the, they had increased their forecast of purchases from us, so that also increased the ...

MR. KENNEDY: So I think as of the last cost of service filing that we had, that CFB Goose Bay was at 24.14, I think it is, pursuant to JAB-1.

MR. HAMILTON: Yes, 24.14.

MR. KENNEDY: Okay. Just keeping that in mind, I wonder if we could turn to **page 14 of your pre-filed evidence**. The first evidence, Mr. O'Rielly. And this was actually a follow-on page from the one again I believe the Consumer Advocate showed to you this morning, and then it continued on with, "Are you proposing a secondary rate for Labrador at this time?" And I'm wondering if you could ... here, I'll read it actually. Maybe ... it's already been adopted, so. It says, "Yes, Hydro is proposing a secondary energy rate to apply to customer service from the Labrador interconnected system that can avail of fuel switching and can purchase a minimum of one megawatt load such as an electric boiler when it is available. Currently the CFB Goose Bay has a contract with Hydro for secondary service for their electric boiler plant. In developing the rate for this service, we use the greater of 90 percent of the value of the customer's avoided fuel cost or Hydro's opportunity cost based on the revenues we could receive by selling it elsewhere. CFB Goose Bay has the alternative to meet its heating requirements by burning oil in their boiler plant. The net revenue from this customer estimated to be $2.8 million has been applied against the overall 2002 revenue requirement for the Labrador interconnected system to reduce firm service rates." The first question I had was, the $2.8 million that's referenced in that paragraph, is that the same number that in effect is what derives the 24.14 revenue to cost ratio? Is it this $2.8 million that's actually driving the substantial portion of the overcollection, if you will, of revenue to cost for CFB Goose Bay?

MR. HAMILTON: Yes. That would be the amount of revenue in excess of cost.

MR. KENNEDY: Okay. Now, I have to admit this paragraph to me was gobbledygook, and that's no disrespect to yourself. That's just my ignorance of some of the terminology that's used in the paragraph. I wonder if you could just put this into a layperson's perspective or language. What exactly is going on here with CFB Goose Bay and why is there a number on the revenue to cost ratio so anomalous as compared to the rest of them?

MR. HAMILTON: Okay. Where it's a secondary rate, it's on as available basis and to the extent you're not even sure if they're (unintelligible) covering the cost of providing that service, that there's no burden on thermal customers.

MR. KENNEDY: Okay. Just, if I can just slow you down. When you refer to secondary rate, what do you mean by secondary rate?

MR. HAMILTON: It's non-firm sales.

MR. KENNEDY: Okay.

MR. HAMILTON: So it's if and when they want it and we have it available.

MR. KENNEDY: Okay.

MR. HAMILTON: Okay. And so in that context the cost of service doesn't assign any firm load requirements to them so therefore there's no demand cost assigned to them. They just use the system to the extent it's available and they would cover any operating cost in providing the energy to them. In Labrador the major operating cost would be purchase power from Churchill Falls. It's not thermal energy that we're selling them. It's through the hydraulic from Churchill Falls. So the purchase power cost is quite low, so in trying to come up with a way to price that kind of a rate, the, it was decided to look at what was the value of it to the customer, in this case DND, if they couldn't buy it from us they'd have to use fossil fuel, and given that we could sell the power elsewhere then there's an opportunity cost to us if we sold it to them. So in this case the opportunity cost is higher than our purchase price from Churchill Falls, so that sort of became our floor price. The upper end in terms of what they'd be willing to pay, they would, you know, see no benefit in paying full cost of fuel, that they could ensure (phonetic) themselves, so in between those two numbers would be sort of a way to cover the rate for them. Historically there was a, they were treated as an industrial customer, I guess, on a contract under the old system, they agreed to pay 90 percent of the cost of oil in their tanks and so we retained that 90 percent level (unintelligible) basically saved ten percent on an operating basis plus they'll save wear and tear on their oil-fired boiler plant, and unless the oil price drops significantly, the floor will not kick in till somewhere down the road. If oil prices drop precipitously, then the bottom price could get more expensive to buy secondary then to burn their own oil.

MR. KENNEDY: So this is energy that CFB Goose Bay may decide that it wants to purchase from Hydro. That's what's meant by secondary, that it's non-firm, that they may or may not purchase it.

MR. HAMILTON: That's right.

MR. KENNEDY: And if they do, they pay a certain rate for it and the rate being determined on the basis of an upper and lower values, alternatively either 90 percent of their avoided fuel cost or Hydro's lost opportunity.

MR. HAMILTON: Right. That's (unintelligible) right now, that's what we're proposing.

MR. KENNEDY: So is there any other mechanism that's employed by Hydro similar to this for setting the price of energy sold to a customer?

MR. HAMILTON: Not in our regulated rates. It's similar to the secondary contract we have with IOCC.

MR. KENNEDY: Which is non-regulated sale.

MR. HAMILTON: That's right.

MR. KENNEDY: Okay. But inside the regulated operations of Hydro, is there any other customer that's treated similarly to CFB?

MR. HAMILTON: No.

MR. KENNEDY: Okay. And to ask perhaps a foolish question, why would this determinant be used for the revenue achieved on the energy sales as opposed to just a straightforward cost of service methodology or why isn't it based on the cost of the, you know, a cost plus scenario?

MR. HAMILTON: The difference with this customer is that it's provided from hydraulic and non-firm sales on the island, in case of the industrial customers, is supplied from a thermal plant. A thermal plant, you can usually measure what the incremental cost of providing the energy. In a hydraulic plant the incremental cost of energy is virtually zero because it's all capacity cost. So in that context you recover virtually no energy charge and currently (phonetic) the customer in this case is deriving a great benefit and so trying to look at other ways to price the incremental sales. An approach used in some jurisdictions would be, we get that kind of luxury item as in you got extra water, (inaudible) power to sell, would be use a market base price. If you could sell it to a customer here for ten cents why would I sell it to him for two cents? In Labrador that, a proxy is the sales to Hydro-Quebec. We can sell it to them for 2.7 odd cents, so therefore that becomes our cost (inaudible), so that's now the cost for that power, and given that they are deriving a benefit from that, that there's a value to them, so if you can come up with a value that's to them that's above the minimal cost that you're willing to forego, then it becomes a bit of a share the savings win-win situation for both. Their cost is lower, our revenue is higher, that revenue gets passed on to other customers so the system benefits, so in that case our other customers are happy, they're still saving money so they're happy.

(2:15 p.m.)

MR. KENNEDY: That sounds dangerously close to a marginal cost base pricing system for CFB, doesn't it?

MR. HAMILTON: In a sense that it's a market reflection, a value price ...

MR. KENNEDY: You look at the value to the ...

MR. HAMILTON: It's priced well ...

MR. KENNEDY: You look to the value of the buyer, the value that this commodity represents to the buyer of it, ensuring that the value of it exceeds what they have to give up to get it, and you're looking at the cost to produce it and therefore ensuring that you receive more than the cost that you are expending to produce it.

MR. HAMILTON: There's marginal pricing involved, not marginal costing.

MR. KENNEDY: I understand that CFB Goose Bay has retained consultants to advise them on the electrical rates that they enjoy from Hydro, is that correct?

MR. HAMILTON: I understand they've got a consultant retained to evaluate their whole arrangement up there in terms of (unintelligible) load, whether to keep their oil-fired system or what to do with it.

MR. KENNEDY: And have you had any discussions with CFB Goose Bay in that regard yourself or your department?

MR. HAMILTON: There's been ... we met with them in Labrador. I gather there's been some meetings, one or two, between the consultant and people from the System Planning area. I haven't met with them further since Labrador.

MR. KENNEDY: If we could just go back to **CA-70**, Mr. O'Rielly. The isolated systems, Mr. Hamilton, because I believe you had indicated the current revenue to cost ratio of the domestic diesel customers is as revealed in that second last column of basically 16 cents to the dollar or 16 percent of the cost, is that correct?

MR. HAMILTON: Under existing rates, yes.

MR. KENNEDY: Under the existing rates. And under your proposed rates you're bumping that up by a penny to 17 cents to the dollar, correct?

MR. HAMILTON: Yes.

MR. KENNEDY: And you state on page five of your pre-filed that the long-term objective is to move to 20 percent?

MR. HAMILTON: Yes.

MR. KENNEDY: Okay. And I believe your testimony was that the reason that Hydro couldn't contemplate moving to a higher number than that over the long-term was that it was constrained by the, in effect the operation of the lifeline block, is that correct, and that the lifeline block in effect puts sort of an economic constraint on just how much of a percentage you can obtain from this particular customer group. Is that right?

MR. HAMILTON: Yes, the 20 percent would be consistent with the lifeline block at 700 kilowatt hours, so proposing a 700 kilowatt hour block continues, so given that, that's 20 percent, and if 20 percent is considered adequate then some (unintelligible) be addressed (unintelligible) lifeline block, either the size of the it or the pricing of it.

MR. KENNEDY: Just a curiosity actually, something that struck me. The lifeline block rate is, as I understand it, tied to Newfoundland Power's rate, correct?

MR. HAMILTON: That's correct.

MR. KENNEDY: So, and we know that if Hydro was to obtain a rate increase, that a portion of that presumably would be passed on to Newfoundland Power, correct, that if Hydro is, for instance, granted its proposal pursuant to this application in its entirety, there's some six or 6 1/2 percentage increase that would be passed on to Newfoundland Power?

MR. HAMILTON: That's correct.

MR. KENNEDY: And then I understand that Newfoundland Power would come forward with its own application seeking a bump up in its own rates in order to be able to pass that increase on to its customers, correct?

MR. HAMILTON: That's correct.

MR. KENNEDY: And it's not one for one because Newfoundland Power generates some of its own electricity, so it's closer to about 60 or 70 percent of that increase actually would roughly get passed on to the customers?

MR. HAMILTON: Approximately 57 percent.

MR. KENNEDY: 57 percent, so let's say 60 percent. So is that number then put back into your figures?

MR. HAMILTON: That's why it moves from 16 percent to 17 percent, cost ...

MR. KENNEDY: 17 percent.

MR. HAMILTON: That's what the proposed rates is ...

MR. KENNEDY: And so this 17 cents on the dollar, if you will, is presuming that Hydro gets its full rate increase and that the full 57 percent of that is passed on through to Newfoundland Power's customers and reflected in the customer rate?

MR. HAMILTON: That's correct.

MR. KENNEDY: Okay. The Government domestic diesel customers, the current rate shows that your, have a revenue cost ratio of 19 cents and that you're proposing to move to 23 cents and then you have churches and community halls, current rate 25 cents, proposed rate 26 cents to the dollar. One of the questions I had was that, as I understand it from previous evidence, there is currently under the preferential rates, and I'm presuming that these form part of the preferential rate scheme, is that correct?

MR. HAMILTON: Yes, preferred rate, yes.

MR. KENNEDY: Okay. And that under that preferential rate there is a total shortfall, if you will, from what's collected as compared to the cost of roughly $2.6 million, I think it was.

MR. HAMILTON: $2.6 is a ... a portion of that from the preferential rates and a portion, larger portion of that is from Government agencies being on/beyond (phonetic) the normal domestic diesel or domestic general service rate.

MR. KENNEDY: So this Government domestic diesel, is that the rate that contributes to that $2.6 million?

MR. HAMILTON: The Government domestic diesel and the Government general service and the Government street lighting, all those accounts that the Government agencies are on, those combined contribute approximately $2 million of the $2.6, I believe.

MR. KENNEDY: Right, okay. So it's Government diesel, 1.2 G?

MR. HAMILTON: 1.2 G, 2.5 G, 4.1 G.

MR. KENNEDY: Okay.

MR. HAMILTON: All those Government agencies combined, there's approximately $2 million of the deficit is related to those customers at the existing rates.

MR. KENNEDY: Okay. Now I believe it was, you can correct me if I'm wrong, I thought it might have been Mr. Osmond gave some evidence about what's actually in the Government grouping, if you will, of customers that would fall under these customer groups, and he indicated that many cases, it would include hospital boards and community hospitals and the like.

MR. HAMILTON: Yes.

MR. KENNEDY: Okay. Now, that wouldn't fall under 4.1, would it, the Government street and area lighting, would it?

MR. HAMILTON: No. That would be street lights ... well, it could be street lights for the parking lots for some of those facilities.

MR. KENNEDY: Okay. So they would get this Government street and area lighting rate of the ... okay. I wonder if we could just turn to **Schedule 2 of your pre-filed, page one**? Do you have that before you there, Mr. Hamilton?

MR. HAMILTON: Yes.

MR. KENNEDY: Okay. So reading this chart, this is a chart which shows the percentage of the customer class that, as a result of the proposed increase, would receive, how much they would receive in an increase in absolute dollar terms. Is that right?

MR. HAMILTON: Yes, the dollar increase resulting from these rate changes.

MR. KENNEDY: And so under the proposed increase for that domestic diesel 1.2 G rate, which is, right now I think it was ... we just had it up there. It's at 23 cents on the dollar, I think it was. Can we just ... it's at ... yeah, it's proposed to go to 23 cents on the dollar from the current 19.

MR. HAMILTON: Yes.

MR. KENNEDY: Okay. And that, just going back to page one of three then, Mr. O'Rielly, thank you, that the, if I'm reading this correctly, 73 percent of that, of the customers that fall in that 1.2 G grouping would receive an annual increase of anywhere from 50 to $400, is that right?

MR. HAMILTON: That's correct.

MR. KENNEDY: Okay. And then a further 17 percent would receive an annual increase of $400 to $750, is that right?

MR. HAMILTON: That's correct.

MR. KENNEDY: Okay. And so roughly 90 percent of the customer class in this 1.2 G grouping as a result of that four cent jump, if you will, in the rate that's being proposed, four cent, on the revenue cost ratio, four percentage ...

MR. HAMILTON: Four percent. Four percent, yes.

MR. KENNEDY: Sorry. Would receive no more than a $750 annual increase.

MR. HAMILTON: That's right.

MR. KENNEDY: Okay. Would you agree with me that even in the case of, well, certainly in the case of a Government department first, a pure Government department, not a hospital board, that a $750 annual increase is not likely to cause, well let's start at the high point, not likely to cause rate shock, is it?

MR. HAMILTON: It's a ... it depends on how big a portion of the budget this constitutes. $750 itself doesn't sound like a lot. You keep (unintelligible) Government departments are large budgets. This is ... how many of these houses or domestic accounts they would have and what department it falls under. It's a 20 percent increase on that portion of the cost.

MR. KENNEDY: Sure. And so does Hydro have that kind of detail about what the budgets are for these particular customers and how much of a jump it would be for them as pursuant to their budgets? You wouldn't have that kind of detail, would you?

MR. HAMILTON: No.

MR. KENNEDY: No. So can you tell me how the determination is made about only to step up the domestic diesel 1.2 G rate by the proposed amount of four percent as opposed to moving much faster than that?

MR. HAMILTON: They're looked at in the (unintelligible) of a total impact and I guess how long it would take to move to 100 percent and to allow them some lead lag (phonetic) time to plan for it in future budgets by having a first step and recognizing that soon it will be an ongoing process for them so that the key part would be to make sure that they allow for it, I guess, in the future.

MR. KENNEDY: Okay, but there was no ... since Hydro doesn't have any detailed information about the size of the budgets of those individual customers, it has no idea of knowing whether this constitutes even in and of itself a lot of money or not a lot of money as compared to their overall budget, correct?

MR. HAMILTON: I have no idea of their budgets, no.

(2:30 p.m.)

MR. KENNEDY: And if we just go to **page three of three of that Schedule 2**, similarly the Government department and agencies general service diesel of the 2.5 G group, now could you just explain to me the general service diesel, how does that differ from the domestic diesel rate for Government departments and agencies? Who would fall under 1.2 G versus who would fall under 2.5 G?

MR. HAMILTON: The domestic rate would be for residential accounts and for houses. This would be for non-residential, commercial type operations.

MR. KENNEDY: Okay. So non-residential commercial operations.

MR. HAMILTON: (unintelligible) offices.

MR. KENNEDY: Okay. And just going back then, Mr. O'Rielly, to **CA-70** again for a second, the 2.5 G general service diesel is right now at 28 percent on a revenue cost basis and you're proposing to move to 34 percent collection of the total cost to service that group, correct?

MR. HAMILTON: Yes.

MR. KENNEDY: Okay. And just going back to **page three of three of Schedule 2**, under that proposal 91 percent, over 91 percent of that customer class will receive an annual increase of anywhere from $40 to $2,500, is that correct?

MR. HAMILTON: That's correct.

MR. KENNEDY: Okay. And again do you have any or does Hydro have any information about whether that constitutes a large increase for this particular customer class in comparison to the budget or their ability to sustain a higher increase?

MR. HAMILTON: I have no information on that, no.

MR. KENNEDY: On **page 13 of your pre-filed testimony**, Mr. Hamilton, I just have a quick question. You indicate at the bottom of page 13 there, "In addition, the prompt payment discount has been expanded to all rate classes and is the same as on the island interconnected system. Minimum monthly charges and alternate energy rates similar to those on the island interconnected system are being proposed for all general service rates." And pursuant to the schedules that you filed with your testimony, I see that the early payment discount is 1.5 percent.

MR. HAMILTON: Yes.

MR. KENNEDY: And there's some maximums placed on that. The minimum is $1 and in some cases there's a maximum placed of $500, correct?

MR. HAMILTON: The maximum ... in all cases most rates don't ... those aren't large enough to reach the $500 level.

MR. KENNEDY: Sure. And now when is a Hydro bill normally payable in the case of it being rendered to a customer? It's 30 day terms or is it due on rendered or ... - overlap

MR. HAMILTON: The account payment discount period is typically ... the account payment discount period is shorter than the late payment charge period. I think it's ten days after the bill is issued, it's the prompt payment purposes.

MR. KENNEDY: So I understand it that under the proposed wording, and this was, I believe, a question received by someone concerning the change in language that Mr. Bowman is proposing to your ability to collect interest on overdue accounts and that it would move from a may to a should. Do you remember that?

MR. HAMILTON: That was regarding late payment, late payment charges, interest charges, for late payments, sorry.

MR. KENNEDY: And that kicks in after 30 days, as I understand it.

MR. HAMILTON: When the next bill is issued.

MR. KENNEDY: Next bill is issued.

MR. HAMILTON: Yes, which is on average around 30 days.

MR. KENNEDY: 30 days. So a person normally has 30 days to pay their bill, in other words, before they would normally be subject to an interest charge for a late payment?

MR. HAMILTON: For late payment, yes.

MR. KENNEDY: Okay. And under your proposal you're granting a 1.5 percent early payment discount if they pay the bill within ten days of receiving the bill?

MR. HAMILTON: That's correct.

MR. KENNEDY: Okay. So in effect then Hydro is paying 1.5 percent to get its money about 20 days earlier than it otherwise might get its money, is that a fair statement?

MR. HAMILTON: 20 days earlier than the late payment charges would come in, I guess. Somewhere between those two numbers when the average person would pay the bill, I guess.

MR. KENNEDY: Right. So do you have a number when the mean is for, or a mode, I guess, of when you would expect a payment from your average customer?

MR. HAMILTON: No, I don't.

MR. KENNEDY: So, but it's anywhere from zero to 30 days presumably.

MR. HAMILTON: That's right, depends with the customer, yes.

MR. KENNEDY: Okay. So has Hydro calculated how much it's going to have to forego in revenue as a result of offering this 1.5 percent early payment discount?

MR. HAMILTON: There hasn't been any special calculation on it partially because trying to determine how many customers are going to change their payment pattern because of it. Until you have some history on which to base the ... it's hard to know. Right now the time of payment, or the payment pattern is fairly evenly spread. There's not a lot in one period or another, last time we were looking at that.

MR. KENNEDY: Okay. In effect though, by offering an early payment discount, Hydro is paying the customer to receive the money earlier than it would otherwise expect to receive the money, correct?

MR. HAMILTON: In effect, yes.

MR. KENNEDY: And that could be anywhere from zero to 20 days earlier than it's normally receiving the money.

MR. HAMILTON: That is correct.

MR. KENNEDY: So you're paying potentially 1 1/2 percent to get your money, anywhere from zero to an extra 20 days earlier than you would otherwise get your money.

MR. HAMILTON: You might say that substantially sooner in that some customers might have lapsed and gone into late payment terms, so there's that element there too, and the other, I guess, benefit of a payment discount, it's a positive item as opposed to waiting until the 29th day and all of a sudden you're going to be billed a late payment charge. One is an incentive and the other is a penalty and it has a more positive aspect to it.

MR. KENNEDY: Sure, but if I'm a typical customer and I usually pay my bill on the 29th day of the month and now I'm offered an early payment discount that says if I pay it on the 10th, on or before the 10th day, that I'll receive a 1.5 percent discount, and I take advantage of that and I pay the bill on the 9th day, you've received the money 20 days earlier than you otherwise would have from me.

MR. HAMILTON: That is correct.

MR. KENNEDY: And you've paid 1 1/2 percent to get that money 20 days faster than I normally would have given it to you.

MR. HAMILTON: That is correct.

MR. KENNEDY: And so annualized that's a particularly high interest to pay on money, is it not?

MR. HAMILTON: It's a good return on the investment.

MR. KENNEDY: For the customer.

MR. HAMILTON: For the customer.

MR. KENNEDY: And so that's revenue foregone by Hydro.

MR. HAMILTON: It's a change in its cash flow and there's expected to be some other benefits involved with it.

MR. KENNEDY: And the 1 1/2 percent, that's not being offered to Newfoundland Power, is it?

MR. HAMILTON: To Newfoundland Power, no.

MR. KENNEDY: No. *(laughter)*

MR. HAMILTON: They pay on the 20th day anyway, I understand.

MR. KENNEDY: Whether they like it or not. Just a last question, Mr. Hamilton. **Schedule 5 of your pre-filed on page two**, the disconnection of service, paragraph (c), "Hydro may, in accordance with its collection policy, disconnect the service upon prior notice to the customer if the customer has a bill for any service which is not paid in full 30 days or more after issuance." Is there a written collection policy that Hydro employs for this purpose?

MR. HAMILTON: There are internal procedures ... there has been ... there's no (unintelligible) policy approved and documented by the Board.

MR. KENNEDY: Okay. By the Board, meaning this board.

MR. HAMILTON: By this board.

MR. KENNEDY: But if I'm gathering correctly there is a policy that Hydro follows in the, in pursuing customers for the collection of its accounts.

MR. HAMILTON: It has a series of procedures for ...

MR. KENNEDY: Progressing ...

MR. HAMILTON: ... first notice, second notice, that type of thing.

MR. KENNEDY: Okay. I'm wondering, Counsel, whether we could just have that filed, the Hydro collection policy?

MR. YOUNG: Sure. We can undertake to file that.

MR. KENNEDY: Thank you. That's all the questions I have, Chair. Thank you very much, Mr. Hamilton.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Kennedy. Thank you, Mr. Hamilton. We'll move now to Hydro redirect, Mr. Young, please.

MR. YOUNG: Thank you, Chair. Mr. Hamilton, when Mr. Hutchings was discussing with you the transformer losses issue, what I seem to miss from the conversation was dollar amounts coming from them, what it really meant. I wonder if I could ask Mr. O'Rielly to go to **IC-227**, please? Mr. Hamilton, could you explain what this table is and what the dollar effects are of the transformer losses impact as shown in this table?

MR. HAMILTON: It's showing the impact of the current treatment and the proposed treatment of the billing of transformer losses, and what you see there is that total dollar amount is not that great but the amount on individual customers is fairly large in some cases, so that Newfoundland Power will have a reduction of perhaps 5., $5,276. The industrial customers as a class, their costs will go up $6,600. Within the industrial class there are some customers that will see that increase. Abitibi Consolidated Stephenville will have an increase of $29,531, Grand Falls, $10,447, Corner Brook will see a reduction of $41,405, and North Atlantic, $8,027.

MR. YOUNG: Mr. O'Rielly, could you go to the next page, **page four of four**, please?

MR. HAMILTON: The other approach that was suggested in this RFI was the concept of having all the losses above 66 treated as common and applied on an average basis to the customer served at that level. To do that would result in an increase in cost to Newfoundland Power of $104,571 and a reduction in cost to the industrial customers totalling approximately $112,000, and the other $11,000 would be assigned to Hydro rural.

MR. YOUNG: So I guess on average it's a shifting cost from industrials to Newfoundland Power, correct?

MR. HAMILTON: Yes, or transfer costs from the industrials to Newfoundland power.

MR. YOUNG: There's been a fair bit of discussion about the RSP. I don't mean to belabour it but I do have to ask one question I think for clarification, perhaps a series of questions on that. I wonder if you could refer to your **Schedule A in your pre-filed evidence**? I think it's page 5 of 27.

MR. HAMILTON: That's in the application.

MR. YOUNG: It's in the application, that's right. It's not your evidence, it's the application. Mr. Hamilton, this what we're looking at is the proposed RSP going forward, correct? It's in our application, as you just indicated. I wonder if you could indicate whether the components on these pages are different or the same as those which are in the present RSP?

MR. HAMILTON: The components outlined in this attachment, page five, six and seven, are the same components that are in the existing Rate Stabilization Plan. There are the three components and they're outlined here and they're showing a formula style, the first component being hydraulic production variation and shows components there being a test year cost of service hydraulic production versus the actual hydraulic production, and using the conversion rate for Holyrood to convert that to barrels and then the test year price. And then you have the load variation component, which has two elements to it, the fuel components, that's the extra fuel consumed related to the change in sales, and on the next page the revenue component, any additional revenues arising or a shortfall of revenue arising from actual monthly sales being different from forecast and unconcluded (phonetic) in the test year, and then there's a fuel cost variation which has actually just the monthly test year fuel cost versus the actual fuel cost times the quantity concerned, consumed for firm sales. So those are the basic three components that were originally in the Rate Stabilization Plan and then the one that was added subsequent to that was a rural rate alteration and that is in Item 4 there, the fourth component, and that's tracking any change in revenues arising from a rate increase due to Newfoundland Power that wasn't allowed for in the test year.

MR. YOUNG: So I understand that the components you just described to us, they're in the present plan and they're in the plan going forward also, correct?

MR. HAMILTON: That's right. Those are the same four.

MR. YOUNG: So earlier today you made a comment indicating that it would be perhaps a good thing if we could (inaudible) this further going forward, which got a reaction. I'm wondering if you could indicate what the difference is in the way ... if these components are the same now as going forward, can you please indicate the difference in the way the RSP is going to be administered and what difference that will effect?

(2:45 p.m.)

MR. HAMILTON: The primary difference between past and future is basically outlined on page seven in terms of the calculation of the cost allocation. The activity is recorded the same basis but there's a split between that and the customers. On a go-forward basis it will be using a 12 (unintelligible), the actual kilowatt hours for energy. In the past it has been used, we've used the cost of service model to actually perform that activity, and that really is, relates back to the cost of service methodology that was used that in the past the average and excess (phonetic) demand methodology, by changing the actual kilowatt hours, it impacted other elements and was felt to be (unintelligible) handled properly the cost of service was used to do the customer splits.

MR. YOUNG: Just to clarify this point, is it the load variation component that's in both the present and the future plans or the cost of service step which appears to have been causing the misunderstandings?

MR. HAMILTON: It would be the customer split that was used in the cost of service study, not the load component. The load component as a revenue variation is in both plans.

MR. YOUNG: And I'm sure Mr. Osler may have something further to say about that. The ... he has already to some extent. I have to distribute, if I may, this is available in hard copy. It's just easier to distribute it than it is to provide it ... the extra time it will take to dig it out of the binder because it's not available electronically. What I presented Mr. Hamilton is an excerpt from **NP-27**. It's actually an excerpt from a customer survey document, and there was a question asked to you this morning by Mr. Browne about information on bills and (inaudible) DSM and I just wanted to clarify. First of all, could you identify what this page is that we're looking at?

MR. HAMILTON: It's the summary table out of the customer satisfaction survey that was conducted in 2000 by Hydro.

MR. YOUNG: And there were some questions asked about what was on the bill and what might be on the bill. I'm just wondering if you could identify the ones on the bottom there? It says education or information about electricity use.

MR. HAMILTON: On the relative ranking of priority by consumers, in both years education or information about electricity use was the least important of the items asked of the customers.

MR. YOUNG: Thank you. Those are all the questions. Thank you, Mr. Hamilton.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Young. Thank you, Mr. Hamilton. We'll move now to Board questions and I'll ask Commissioner Powell to begin, please.

COMMISSIONER POWELL: Thank you, Chair. Good day, Mr. Hamilton.

MR. HAMILTON: Good afternoon.

COMMISSIONER POWELL: I only have a couple of items. Looking last evening and I was going through your evidence again and through my notes, I noticed that your professional qualifications, you've 18 years' experience. Am I to presume that your work experience is in Newfoundland Power and Hydro?

MR. HAMILTON: Yes.

COMMISSIONER POWELL: So your whole work experience has been in this sort of environment.

MR. HAMILTON: Yes, it has.

COMMISSIONER POWELL: Okay. For better or for worse. Might I ask how do you heat your home?

MR. HAMILTON: Electric heat.

COMMISSIONER POWELL: All electric, hey? Baseboard or ...

MR. HAMILTON: Baseboard, yes.

COMMISSIONER POWELL: Is that common pretty well throughout the group, deals with your section in Hydro?

MR. HAMILTON: I really don't know.

COMMISSIONER POWELL: It's not something you sit down and talk about?

MR. HAMILTON: No.

COMMISSIONER POWELL: You don't look at advantages of oil-fired heat as opposed to electric?

MR. HAMILTON: I don't know what others do but I know what I did when I had my house built.

COMMISSIONER POWELL: So it's a recent home?

MR. HAMILTON: No. It's 20 years old.

COMMISSIONER POWELL: Oh, okay. So you got those old appliances gobbling up all that electricity, huh? The thing that struck me when I was reading everything, and I don't want to appear to be cynical but sometimes when you're looking at things you have to throw it up in the air and look at it at all sides, and I was thinking that there's a good chance that everybody or the majority of people in around Hydro are electric domestic consumers, and you're sitting down and you're doing all this rate design and that. It sort of comes across on sort of an appearance of a bias against the industrial customers because you sit down and you crunch the numbers and you say, oh, there goes my bill again, I wonder what I can do about that, because when I got the application, I'm an (inaudible) user myself. Then when I got the application I went down the, after I read it, I sat down and figured out what the impacts on me going forward and I said, oops, so I'm, I have some question about being biased and being here, but then I sat down and realized that I live in a town where a large industrial user, and if he gets indigestion or they get indigestion from their electricity bill, my rate increases, that's not the least of my worries because I have some other concerns, so I feel very comfortable sitting here. So when you do your design, your rates, do you have any consultation with the industrial customers once you get the numbers crunched out?

MR. HAMILTON: I'm hesitating in the sense that this year because of the ... historically there was always a contract involved and there was a different arrangement, and this past year there's been a new contract being discussed, so there have been ongoing consultations with the industrial customers in the context of the actual rate design that we are proposing here, I guess, given that certain elements are included in the rate, in the contract, the approach was dealt with in those discussions in terms of a firm, non-firm component. In terms of the level of the rate, they wouldn't have known that until the application was filed, so I guess some structural issues were discussed in the course of the contract discussions but not the actual levels, I don't think, but I wasn't actually in those meeting so I, some things I haven't discussed about that.

COMMISSIONER POWELL: On **page four, line nine, ten of your pre-filed evidence**, you state that, "Generally the cost of service study results provide an indication of the approximate level of cost recovery from each rate class." So that sort of surprised me with the use of the word "indication" because I was sort of thinking that with all the sophistication and everything we have that it was going to be a lot more precise. So then when I looked, I guess, stand back and look at what we're doing here, I mean, Hydro really only has two classes of customers, is the industrial customers and Newfoundland Power. The rural customers' rates are driven by what Newfoundland Power has, the Labrador is unique onto itself, and the isolated systems are, as we just found out, that the, or we know from evidence, recovery very small portion of their costs, so most all ... and those costs can be identified. So the bulk of your costs are the two classes. Then we give thought to extracting those costs applicable to the, your Labrador and your isolated and then saying the rest of the costs, saying to Newfoundland Power and the industrial customers, this is what we need to recover, you fellows go to one side and figure out how much you want to do yourselves rather than going through this process, because Newfoundland Power's health is dependent upon the industrial customers' health, because there's a large portion of their customers depend upon the health of the industrial customers, so rather than going through the exercise of designing rates and almost a confrontational type of an approach, you take that and I'll take that sort of thing, letting them come back. Any thought given to that approach?

MR. HAMILTON: Yes. The ... usually the cost of service tries to make it as objective as it can and in the context of cost of service study, Newfoundland Power's rates and the industrial rates do flow directly out of those. Usually what will transpire and probably why you still need some kind of mediation process, whether it's this or another one, are issues such as the plant assignments that drive the cost, and, you know, in the case of some of these items, as we've heard questions on, for the most part if it's to one customer's benefit it's to another's disbenefit *(sic)*, so I think ultimately several items would still have to come to some place for adjudication on it.

COMMISSIONER POWELL: Wouldn't you think those two classes would be better to adjudicate that amongst themselves as opposed to a forum like this?

MR. HAMILTON: Some elements probably could be handled in a different setting but I think ultimately some items would require adjudication at a, some kind of a tribunal or unbiased body.

COMMISSIONER POWELL: Well, having the rates, having them brought towards a panel like ourselves to approve after they agreed on all the issues, if not most all the issues, would be a lot simpler process than what we're doing now in terms of cost.

MR. HAMILTON: Yes.

COMMISSIONER POWELL: Because the process we're doing now is fairly expensive in terms of cost of service.

MR. HAMILTON: Very expensive.

COMMISSIONER POWELL: From everybody's point of view.

MR. HAMILTON: That's right.

COMMISSIONER POWELL: Any discussions, thoughts to that approach? Has it been (inaudible)? Has Hydro ... internal Hydro ...

MR. HAMILTON: Yes. There's general discussions without being very specific. There's so many issues on the table, being the first time for Hydro to be on a rate of return basis that I guess to the extent that certain items have to be addressed for the first time to get some better benchmarks. A lot of items first time around would be inevitable, but certainly if there's a way to shorten the process for the next time around, I can think of numerous people that'd be quite happy to do that.

COMMISSIONER POWELL: You've had no preliminary discussions with Newfoundland Power and/or industrial customers about some sort of a mediation process versus this, to your knowledge?

MR. HAMILTON: I haven't been involved in any.

COMMISSIONER POWELL: Page 12, we're into the Labrador system. Line seven, you said, "As indicated earlier, Hydro is proposing to move to one set of rates for the Labrador interconnected system consistent with having one cost of service for the system." That cost of service, you're talking about the Labrador system?

MR. HAMILTON: Yes.

COMMISSIONER POWELL: Okay. On page seven, line six, you propose to integrate the 24 existing rates in Labrador into a set of 6 uniform rates. I'm not sure I really can grasp why you want to go from 24 to 6.

MR. HAMILTON: Currently in Labrador you have, for example, three different domestic rates. You have ...

COMMISSIONER POWELL: That's ... could you tell me where the three separate domestic rates are?

(3:00 p.m.)

MR. HAMILTON: There's one for Happy Valley-Goose Bay, there's one for Lab City and one for Wabush. The structure is different for Lab City. They have ... it's four blocks, declining (phonetic) block rate. Wabush is more similar with Happy Valley-Goose Bay, and Happy Valley-Goose Bay, the same structure is on the island, but there's three different structures there, the general service ... the groupings of customers is different. How you determine what rate qualify, what customer qualifies for what rate, varies within those three geographic areas, and then the rates themselves are designed differently. For example, in Lab City it's a function, it's single (unintelligible) three phase regards to size of customer. Wabush has small electric rates, electric heat rates, so you have very much a variety pack of what rate applies to a given customer.

COMMISSIONER POWELL: Who does this inconvenience?

MR. HAMILTON: It's ... from an administration point of view it's confusing and difficult. From a customer dealing with them, they, like, compare themselves with another comparable customer elsewhere and try and understand why they're on this rate versus that rate, that causes confusion for the customer, so (unintelligible) with the customer explaining, for example, the impact of like a rate change or change in approach, it gets confusing for dealing with the customer. Given that there's different structures involved raises issues of equity amongst similar customers. If you got two similar customers billed on totally different set of rate structure, is one being billed correctly or incorrectly, more fairly than the other, so it's, it raises a variety of those types of issues.

COMMISSIONER POWELL: When we were in Wabush we had a presentation from the people there and they didn't find any inconvenience to them, existing pattern, and they were very adamant that Hydro is proposing to take away one of the uniqueness, one of the opportunities that they were able to provide to people wanting to move in the area, was their low residential rates, and they felt that, I don't want to be putting words in their mouths, but they left me with the impression that they didn't think reducing the rates or combining the classes from 24 to 6 would be in their best interest. So what would you say to them?

MR. HAMILTON: I guess the domestic rate in Wabush is, right now it's higher than Lab City, which is four or five miles down the road, so that is confusion for them.

COMMISSIONER POWELL: It's probably the people in Lab City spoke to me. I'm the one confused here.

MR. HAMILTON: Generally speaking at any rate structuring, customers that perceive the rate will go up will be against it, those that expect the rates to go down will be in favour of it, and in the case of Lab City and Wabush, looking at the cost recovery levels that, even without combining the rate classes, that domestic rate class is being heavily subsidized by the general service rate classes in those areas and that they're currently at 70 percent or less of their cost recovery, so they would be over time receiving large increases without even worrying (phonetic) about the Labrador interconnected rate, so in that context they would be not happy about that either. The integration for the whole of Labrador, there's benefits and disbenefits to that.

COMMISSIONER POWELL: One of the questions raised was that they didn't think there was any relationship between what went on in the Goose Bay area versus what went on in the Lab City or Wabush area, and even though the power is coming from the same source there was no common cost other than that which is fixed (phonetic) and they didn't think they need to. Do you have any comment on that?

MR. HAMILTON: Well that's typical of any type of interconnected system, that, you know, people on the west side of the island versus the east side of the island, they have somewhat different economies and issues to deal with and those, for example, close to Bay D'Espoir would say I just want Bay D'Espoir power, I don't want the expensive thermal. Let that be for St. John's, let them pay for Holyrood and don't send my bill, thermal to me, so you get those same kind of perceived equity issues around the island, should a customer in Port aux Basques, Corner Brook, St. Anthony, St. John's, Grand Falls ... it would easy to assume that the cost would be different because of the very different locations and arrangements and things, expect some of those people are higher or lower, but to try and differentiate the kind of costs to have, a wide range of precise costs, would be hard to identify who drives what cost and it's part of whole (phonetic) averaging that'd be typical of any electrical system.

COMMISSIONER POWELL: But the Labrador system is a little different than the island's system though, is it not in terms of that? I mean, it's very easy to define your costs in Labrador.

MR. HAMILTON: Any costs of any system associated to a wide range of allocations of any cost of service study, you cannot identify for St. John's what portion of Holyrood goes to St. John's versus elsewhere or Bay D'Espoir goes one place or another, and somebody in Labrador. It looks simpler because it's not as many different points on it but you cannot track all costs precisely and if you did you'd end up with very volatile items because it's peaks and valleys (unintelligible). If you have a storm on one side that affected Lab City one year and they paid all their costs, well then their rates will go up the following year. And if next year there was no storm or there's a storm in Happy Valley-Goose Bay, then it would constantly move around, but if you got staff there dealing with all common items, you've got common plant, various elements of different costs involved. Similarly over in Happy Valley-Goose Bay you have, for example, the secondary customer, DND, and the benefit that they are putting into the Labrador system and that three and a half million dollars significantly would reduce the cost of service in the Happy Valley-Goose Bay area, and right now that benefit is being shared all across Labrador, so there are many pluses and minuses with any system, and if you're only trying to take all the good things and leave all the bad things to someone else then you'll have other problems.

COMMISSIONER POWELL: Do you think you've done a very good job communicating the idiosyncrasies of the detail that goes into the rate design to your customers, especially some where there's a significant change now in your Labrador area?

MR. HAMILTON: It's very difficult to explain the intricacies of the rate design process to people in general.

COMMISSIONER POWELL: Not so much the rate design but, you know, the things that go into it, you know, some of the things you've just mentioned to me.

MR. HAMILTON: When we went to Labrador, right after we made the application and did presentations to the various councils in Happy Valley, Wabush, and Lab City, we invited the Chambers of Commerce in each of those areas. We had, I think, one representative in Happy Valley-Goose Bay and one attended, I believe, in Lab City, and that was the level of interest that was created. There wasn't a lot of advance notice, I grant you, and there was some timing conflicts. We subsequently went back to Happy Valley to meet with the Happy Valley Chamber of Commerce, but it's difficult to get everybody together to explain things to them. It's, as we see, a very involved process. It doesn't lend itself to easy explanations to customers.

COMMISSIONER POWELL: But it's an ongoing education as opposed to once the fire gets started, trying to put it out.

MR. HAMILTON: I agree, it's an ongoing process, but to the extent that there's no burning issue to attract your attention, it's difficult to get people to come to listen to such a presentation. It's not, you know, a lively and thrilling topic.

COMMISSIONER POWELL: One other question, it's not in your, probably directly in your area, and it was sort of touched on this morning, and I meant to ask Mr. Osmond about it with his Rate Stabilization Plan, is that, it was mentioned the prior application that Hydro had put in a multi-tiered specific rate for the price of oil changing each of three years. Any thought to when you're doing the price of fuel, to do an annual price of fuel adjustment, based on some sort of a formula so you don't get locked in as you did before with the $12.50, so if you had three or four years based on the average price over a period of a specific time in the year, and use that? Does that complicate the things?

MR. HAMILTON: I don't think there's been formal discussions about the possibilities to deal with it, nothing ... (inaudible) time spent looking at it, other than brief discussions and points in time are difficult. In the last two months we've seen several (inaudible) changes in direction. To pick a point-in-time price is very difficult, so trying to come up with a, I guess, some kind of time period to use as a reference point, that would be the difficult part, but certainly such an item could be investigated.

COMMISSIONER POWELL: You didn't (inaudible) any scenarios to see what would happen if you did change your base each year given the certain amount of complications in reworking the plan, did you ...

MR. HAMILTON: The analysis could be performed to look at various timing options. The problem with, I guess, one of the aspects we kept bumping into is how do you change your base rate that ties in with it without having a hearing process, but ... so it could be, it would be hard to keep it very simple, but again, there wasn't a whole lot of time spent at it, just, I guess, semi, informal kind of discussions about other ways of doing it, and there's nothing obvious that came to mind, so we kept our attention on the hearing prep as it was.

COMMISSIONER POWELL: Thank you, sir. That's all, Mr. Chair.

MR. NOSEWORTHY, CHAIRMAN: Thank you,

Commissioner Powell. I understand that between us we have a very few number of questions so I'm going to try and conclude the Board questions before the break. Mr. Saunders, if you would please?

COMMISSIONER SAUNDERS: I just had one question, Mr. Chair. Going to **CA-70**, Mr. Hamilton, page 2 of 3, and it was arising from a question that Mr. Kennedy asked, and I guess it was arising as well from questions that the Consumer Advocate asked this morning. As I understand it, the, what I'll call subsidized government rates all appear in the isolated systems heading, under the isolated systems heading, is that correct?

MR. HAMILTON: Yes.

COMMISSIONER SAUNDERS: The question that arises in my mind is there are government facilities similar to what you have under isolated systems located in other parts of your service area ... for example, St. Anthony, which I would assume now appears under island interconnected.

MR. HAMILTON: That's correct.

COMMISSIONER SAUNDERS: Are there any government subsidized institutions that appear in these headings outside the isolated systems?

MR. HAMILTON: Not that we know of in the sense that all the general service classes are covering their costs in the island interconnected rural system. There would be probably some domestic customers ... in the same way on the isolated systems there are domestic (inaudible) for government agencies, and the domestic class isn't *(phonetic)* 100 percent cost of service, so that would the be only item I could think of.

COMMISSIONER SAUNDERS: So there's no other subsidies, if we can call it that, the government institutions or buildings or agencies or departments outside of what appears under the isolated systems heading and which are identified as government domestic diesel, government general service diesel, government street lighting.

MR. HAMILTON: The only other item would be possibly that 1.3 special category and that's a library in Burgeo, and I don't know if that would be classified as a government agency or not.

COMMISSIONER SAUNDERS: How about the subsidy, if we can call it that, to the town of Bay d'Espoir?

MR. HAMILTON: Street lighting.

COMMISSIONER SAUNDERS: Street lighting, yeah, where would that appear, or does it appear here?

MR. HAMILTON: Municipal governments are not treated as provincial government agencies.

COMMISSIONER SAUNDERS: So when you, I understand that ... so, okay, go back to my original question. To your knowledge are there any other examples of subsidized government agencies or departments appearing anywhere in your system outside of the isolated system?

MR. HAMILTON: Unless there's some in L'anse au Loup which is isolated but using the island interconnected rate, that would be the only other location.

COMMISSIONER SAUNDERS: You're not certain. Can you take it upon yourself to find out the answer, if you're not certain, as an undertaking, Ms. Greene.

MR. HAMILTON: Yes.

COMMISSIONER SAUNDERS: Okay, that' all I had, Mr. Chair.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Commissioner Saunders. Commissioner Whalen please?

COMMISSIONER WHALEN: Good afternoon, Mr. Hamilton. I just have one question. Actually I think it's two. You just mentioned that 1.3 special rate that was ... it was a library in Burgeo. Why wouldn't you have in this application collapsed that into one of the other rates? Is there a reason why that continues to be special?

MR. HAMILTON: It's a long-standing rate that was ordered some years ago, and we just decided for this hearing not to really address preferential rates in general, with the exception of the ones for government agencies, so we left that in the category that it was a preferential rate set up for a special reason.

COMMISSIONER WHALEN: Okay, the only other question I had was relating to your discussions with Mr. Kennedy, and also to some extent, Mr. Powell, in relation to the secondary sales in Goose Bay. I just, I understand that there is a $3 million, it's about a $3 million benefit, or I guess revenue over costs that accrues from those sales.

MR. HAMILTON: Yes, in the original filing it was about $2.8 million, and the revised filing is about $3.7 million.

COMMISSIONER WHALEN: Okay, so you had just said that that revenue goes in to reduce the overall revenue requirement for the Labrador interconnected so the benefit accrues to customers in Goose Bay, Labrador City, and Wabush.

MR. HAMILTON: Yes.

COMMISSIONER WHALEN: I guess my question is because that reduction is resulting in an average overall decrease for those retail rates of about, well I think it's 4.9 percent, would you be violating any rate design principles if you took that three and a half, or $3.7 million and applied it against the rural deficit and didn't apply it to produce a decrease in revenue requirement in a system that already enjoys low rates?

MR. HAMILTON: No, it's sort of a reverse subsidy in the sense that it's excess revenue and who do you apply it to ... so I guess, we've kept the revenue (inaudible) from the island portion on the island and the Labrador portion in Labrador, and that's the course we have used. It's certainly being used in a broader sense.

COMMISSIONER WHALEN: So it isn't, it isn't cast that it needs to be applied to the interconnected system because it's derived from the interconnected system?

MR. HAMILTON: It's ... you could make the argument to apply it to the whole system in the sense that there's already portions of the rural deficit being assigned to Labrador and they aren't incurring the deficit in Labrador, and therefore there's revenue credits from Labrador the island could be put into a pot similarly and allocated the cost of the two systems on some basis, so in that context, but the difference being the deficit, there is a substantial portion of the deficit created in Labrador, so a portion of the deficit therefore is allocated to Labrador.

COMMISSIONER WHALEN: I guess that's where my question is coming from, that the origin of the deficit is on the systems in Labrador.

MR. HAMILTON: There's a fair portion there, yes.

COMMISSIONER WHALEN: The people who pay for the deficit are primarily customers on the island, is that right?

MR. HAMILTON: There's a higher proportion coming to the island than that's incurred in the island, yes.

COMMISSIONER WHALEN: So it's ... okay, I'll just leave it at that.

MR. HAMILTON: Yes, yeah.

COMMISSIONER WHALEN: Just looking at it from a rate design principle perspective, that's all. That's all the questions I have, thank you, Mr. Hamilton.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Commissioner Whalen. Good afternoon, Mr. Hamilton. Up until a minute or so ago I didn't have any questions, but there's one that was prompted by Commissioner Powell, and I probably made the wrong decision here, I apologize to the coffee drinkers and the smokers, but I certainly won't keep you much longer. It relates actually ... the lifeline block, does that apply to municipalities in the Labrador diesel system?

MR. HAMILTON: It applies to the general service diesel accounts so if they have a general service account then they would benefit from the lifeline block.

MR. NOSEWORTHY, CHAIRMAN: So the street lighting and that, I thought I heard you indicate that the street lighting, the government service street lighting generally didn't apply to municipalities.

MR. HAMILTON: The street lighting rates are right now in the diesel areas the same as on the interconnected rates, but the government street light rates would be going up, but that's for, it's area lighting, but the municipal street lighting is not considered a government account.

MR. NOSEWORTHY, CHAIRMAN: The origin of my question really, I can recall when we had the public participation days in Labrador, there was some people there, municipal councillors and mayors, I believe, representing municipalities and in certain instances, I know their electric bills as a percentage of their budget would have been quite high and I think part of it was due, in the municipalities that I recall, was where they would have had sewage treatment and water treatment plants that would probably in relation to consuming electricity, consume a fair bit. I don't know how it would compare to street lighting, for example. Has there ever been any consideration given to a rate associated with that or any discussions ever occurred with the municipality, or have they approached Hydro on that at all, do you know?

MR. HAMILTON: Not that I'm aware of.

MR. NOSEWORTHY, CHAIRMAN: It just seemed to relate, the areas where the, the communities where there were high electric bills, again, as I say, it seemed to be where they had treatment plants of some sort. In other areas I think they were more in line, and that was just an impression that I got at the time, but anyway, I'm sorry ...

MR. HAMILTON: A treatment plant would be considered a general service customer and they would fit in the rate class according to, because they're on the interconnected system, depending on the size of the treatment plant, small, medium, large, general service.

MR. NOSEWORTHY, CHAIRMAN: So in relation to if the lifeline block applied there, presumably that would be on a marginal basis and they would be paying considerably higher rates?

MR. HAMILTON: In the isolated areas?

MR. NOSEWORTHY, CHAIRMAN: Yes.

MR. HAMILTON: Yes, they would get the first 700 kilowatt hours at the interconnected rate, and then they'd swing into the higher rate.

MR. NOSEWORTHY, CHAIRMAN: Sure, okay, thank you very much, we'll break now for 15 minutes, thank you.

(break)

(3:45 p.m.)

MR. NOSEWORTHY, CHAIRMAN: Thank you, we'll move now to questions on matters arising, Ms. Butler, please.

MS. BUTLER, Q.C.: No, Mr. Chairman, we have no questions arising, thank you.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Hutchings.

MR. HUTCHINGS: Nothing on behalf of the Industrial Customers, thank you, Mr. Chair.

MR. NOSEWORTHY, CHAIRMAN: Thank you, sir. Mr. Browne or Mr. Fitzgerald.

MR. BROWNE, Q.C.: Yes, just one. I wouldn't want something left on the record there which may be inaccurate. The counsel for Newfoundland Hydro asked you concerning your survey and the importance factors of 2000 versus 1999, concerning education or information about electricity use, and you stated it was the last in the ranking of the last two surveys, is that accurate?

MR. HAMILTON: That's what I said, yes.

MR. BROWNE, Q.C.: And what is the question that consumers are being asked there?

MR. HAMILTON: It's a, I guess a category of questions that were asked. I don't have the questions in front of me.

MR. BROWNE, Q.C.: Yeah, they're asked concerning their education or information about electricity use.

MR. HAMILTON: Yes.

MR. BROWNE, Q.C.: Now what are consumers being offered there? Are they being offered a biography of Thomas Edison, is that what they're being offered? How would you know what you're being asked based on that category?

MR. HAMILTON: I don't know what questions are asked in that category.

MR. BROWNE, Q.C.: I would suggest that the question is put consumers education or information about electricity use which could save you money, if they're asked that question that you might get a different response. Would you agree that you mightn't find that ranking so low in that instance?

MR. HAMILTON: I'm not aware what question to actually ask, so I ...

MR. BROWNE, Q.C.: Okay, it's just something I didn't want to leave on the records, to suggest that the consumers are not interested based on the telephone survey. Thank you very much, sir.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Browne. Mr. Kennedy?

MR. KENNEDY: Nothing arising, Chair.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Young, any redirect?

MR. YOUNG: Nothing arising.

MR. NOSEWORTHY, CHAIRMAN: That concludes your work for today, Mr. Hamilton. Thank you very much. I appreciate your testimony. We have 40 minutes, Mr. Hutchings. Are you in the position to introduce Mr. Olser at this point in time?

MR. HUTCHINGS: Yes, Mr. Chair, we're in a position now to begin with Mr. Olser's evidence and I'll have a number of questions by way of direct examination and I would think we'd be able to get through those before 4:30 and allow Mr. Young to commence cross-examination in the morning.

MR. NOSEWORTHY, CHAIRMAN: Thank you.

MR. HUTCHINGS: I'll call Cam Olser.

MR. NOSEWORTHY, CHAIRMAN: Good afternoon, Mr. Olser. Do you swear on this Bible that the evidence to be given by you should be the truth, the whole truth, and nothing but the truth, so help your God?

MR. OLSER: I do.

MR. NOSEWORTHY, CHAIRMAN: Thank you sir, you can be seated. Would you care for a couple of minutes to get your binders sorted out and that, Mr. Olser?

MR. OLSER: I'm fine, thank you.

MR. HUTCHINGS: Would you state your name and address for the record please?

MR. OLSER: Cam Olser, Winnipeg.

MR. HUTCHINGS: Okay, Mr. Olser, you have pre-filed in this proceeding, evidence dated August 15th, 2001; supplementary testimony dated September 12, 2001; and second supplementary testimony dated November 25, 2001, do you adopt these three items as your evidence for the purpose of this hearing?

MR. OLSER: I do.

MR. HUTCHINGS: I note that Attachment A to your evidence of August 15th, 2001, contains your resume and reports you to be the Founding Partner and President of Intergroup Consultants Limited of Winnipeg, is that correct?

MR. OLSER: Yes, it is.

MR. HUTCHINGS: The resume goes on to describe your various, a number of various assignments that you've had and activities that you've undertaken, without getting into the detail of that could you just characterize for us the classes of clients for whom you have worked in this field?

MR. OLSER: In the utility regulatory field, which is not the only thing I do in life, I have worked with industrial customers in Ontario, Manitoba and Saskatchewan, and with the Crown utility in Yukon. Our company currently works with the Crown utility in the Northwest Territories and from time to time we have probably done a few other things with industrial or the representatives of some other jurisdictions, but that's the focus of my experience since roughly the late seventies.

MR. HUTCHINGS: Okay. In respect of this particular matter, what was it that you were requested to do by the industrial customers who have retained you here?

MR. OLSER: As set out in the testimony, to identify and evaluate the issues relating to the two aspects of the Hydro filing, taking into account normal regulatory review principles and procedures appropriate for Canadian electric power utilities, and the two aspects were first, the revenue requirement for the test year 2002 as submitted by the Applicant; and the second question is the cost of service and rate structures, particularly insofar as these affect the island industrial customers.

MR. HUTCHINGS: Okay, and could you briefly outline your approach and the testimony that was pre-filed initially, dated August 15th, 2001.

MR. OLSER: Yes, I'll do this by referring to the third section, starting at page 4 of that testimony. Essentially we reviewed with the industrial customers some of the issues and concerns that they had, because frankly coming into this assignment, we had no prior background in this jurisdiction and those were set out in the second section of that first submission, but in the third one having looked at the application and discussed some of the issues of industrial customers, we set out, if you like, certain issues arising under Section 3.2. First of all, it seemed to us that the context of the application needed to be examined under 3.2(a) because there'd been a fair amount of time since the last hearing on these matters and there seemed to be a fair number of things in terms of legislation that had occurred, and that was addressed in this first submission of August, in Section 4. We secondly thought that pursuant to our terms of reference we should be examining the revenue requirement and the overall rate increase and that's addressed, and I guess talked about in Section 5 of the August 15th submission. Thirdly, the cost of service and rate design matters which was the second major heading that we were asked to look at. Obviously, there were a number of matters we should address there. We started off in the early days, in the August submission, by putting down what could be called, I guess, a listing of issues, because we didn't think we had enough information to do much analysis yet.

The September 12th supplementary evidence utilized information we had by then received and addresses primarily the cost of service and rate design matters. The, at the time we did the initial review of issues, as you see here in August, we had a fourth category called Rate Stabilization Plan. Probably at that stage it was more of a mystery to us than something, that we thought might take a little time and so we set it aside at the end of the exercise as something to pay attention to and it's addressed in Section 7 of the initial evidence. It was addressed in further detail in the September 12th supplementary evidence, particularly with respect to what I will call the go-forward program as proposed in the application, 2002 and beyond, but we still had some significant questions outstanding with respect to the history of the program to that time, to the date of the application and the test year, and when those questions were answered at the start of this week, I think we filed the third supplementary evidence, the second supplementary evidence dated November 25, and that frankly just focuses on the RSP up till the time of the test year and issues relating to that.

MR. HUTCHINGS: Okay, so with regards to RSP the primary go-forward focus is in the September 12 evidence and the historical focus is in the November 25th evidence.

MR. OLSER: Correct.

MR. HUTCHINGS: Okay. Alright then moving along then to Section 4, can you just summarize for us your review of the context of the application as it was presented to you.

MR. OLSER: The bottom of page 6, top of page 7, we summarized certain things that we thought were important, based on a review which is in more detail in the Attachment B to this August filing, essentially some of the key factors seemed to us to be things that we thought we should pay attention to are listed at the top of page 7. Regulation of industrial rates by the Board for the first time in a general application proceeding, that seemed to be a contextual matter of some importance. Redirection of industrial customers, redirection in the sense of the law and the regulations of this jurisdiction are not to be allocated any of the charges required to subsidize rural customers. This would be the first time that rates would have been thought through with that direction. Thirdly, the new questions about Hydro's fair and reasonable level of return and ability to maintain a sound credit rating in that context seemed to be a new direction, at least the Applicant was suggesting that this flowed from the changes that had occurred since the last time they were before the Board on this matter, and finally a change to the rate base approach to adopt, if you like, a rate base approach to regulation which would involve, of course, the test of the usefulness and prudent acquisition of assets that go into the rate base. So it seemed to us that there were, those four were very fundamental new contextual matters arising from the changes that had been going on.

We reviewed the legislation, which I won't take up here, but if I go to page 9, Section 4.1.2, we distilled, distilled the thought with respect to the implications arising from the legislation on the application and in the second paragraph our review effectively, to me anyways, indicated despite all the changes that Hydro in many respects had not substantially been changed as a corporation or been placed in a substantially different financial position as a result of the changes in legislation and there are a whole bunch of things listed that seemed to us to still apply, and I listed them thereafter, in terms of risks or the services they have to provide, or the monopoly environment in which they are working, the security of the revenues they would receive, the likelihood that they would be able to meet their debt obligations, the extent to which they continue to operate or to act as an instrument of government policy, at least in certain respects, the government continued guarantee of their debt and no indication that it was going to be removed, and to a certain extent the continuation of the close relationship, if you like, with the government for the benefit of the corporation and the ratepayers. So there are a lot of very, continuations, is what struck me, despite other things. There was a fundamental change overall which is now the Board, this Board, would be regulating the rates and determining the rate of this Corporation. That was, in the Manitoba jurisdiction which I live that fundamental change took place in the late 1980's and it is a fundamental change and it has lots of implications, once you get through the first hearing.

(4:00 p.m.)

MR. HUTCHINGS: Okay.

MR. OSLER: and I could well understand we might have some interesting issues arising from that. So, in summary, there's lots of detail there because we had to try and get familiar with things that are very familiar to you, but that's what I would highlight.

MR. HUTCHINGS: Okay, so that Section 4 then deals with the contextual issues and we move then to Section 5 of your evidence which deals with revenue requirement and overall rate increases. Could you just highlight the principle points that struck you with respect to the application at the time of filing the August 15th evidence under these headings.

MR. OLSER: I'll deal with it, sort of in a summary fashion. The very beginning of that section, in a very high level review, there seemed, if you look at the revenue requirement section of the review, you would be looking at the things that affect the company's revenues and costs, and the extent to which the operating environment or the issues they're dealing with are different than the last time you were looking at them. There seemed to be in the application itself an assertion of two fundamental changes, one was relating to the oil price and the other one was related to a new legislative regime that would require a rate of return quite different than what it had before, and what struck us on the first review of the material was that in many respects neither of these fundamental changes were going to be fundamentally reflected in this application, less than half of the oil price would be passed through to the new rates and the fundamental changes that were talked about, if they really existed with respect to rate base regulation, are certainly being deferred until the next hearing. So it was interesting and certainly indicated that this was a first step in a process that had maybe some more steps to come, in both cases.

MR. HUTCHINGS: In your reference to the oil price I think you referred to less than half of the oil price being put in was less than half of the change in the oil price.

MR. OLSER: Right, from the base of $12.50 to the prediction of 28 something. Only 20 bucks was put into the new rates as applied. So we looked at it a little bit more deeply than that obviously in Section 5.1 in terms of reviewing the revenue requirement materials, the predictions for the test year relative to what was forecast to have happened to the previous year, or indeed forecast ... what had actually happened in 1992, just to see what had really changed and how many places there seemed to big issues and the fundamental conclusion of that was that, yes, oil prices were indeed a driving factor. There were some other things that were interesting in depreciation and interest but they didn't really drive our attention and in terms of a number of other cost factors. We went through them at least at the global level as one would do in my line of work. There weren't things that leaped out at us that would require a lot of our attention. We assumed others would probably look at those matters in more detail if (inaudible) more experience here.

Overall, as stated on page 13, after the bullets, what struck me was the extent to which that this would very much likely be an investigation that would look beyond the test year on one hand to see how you would plan to move forward. Certainly from an industrial customer point of view, given their interest in the long run, it's very important to them to encourage a process that looks forward, at least in the jurisdictions I've worked in elsewhere, that has been a fundamental interest of industrial customers given that they have a stake in the jurisdiction in the long run, they want to know where the rate is going, but in this case, aside from looking forward beyond the test year, there would be, I thought, some interest in the last ten years or so, because given the time period since the last time you were all before the Board and some of the issues that seem to be arising from that. So those are the key points that I would emphasize from that. In terms of the balance of the review that we did on revenue requirement matters, I think the only one I would emphasize at all beyond what's already written here in Section 5.3, return on the equity and debt equity levels. We did answer a question from Newfoundland Hydro in No. 93, to make it very clear that we are, I'm certainly not appearing as a cost of capital expert, and any comments I've made in this testimony are not in that vein. They're in the vein of trying to look at revenue requirement issues and see from, at least my experience, where there might be some need for discussion and the question of the extent to which the new regime requires a totally new approach, it struck me was a question at the appropriate time to be discussed. Whether this is the hearing or it's the next hearing is an interesting question on that which I didn't get into, but fundamentally in the jurisdiction in Manitoba, Manitoba Hydro is still not regulated as a rate based utility but it just purchased Central Gas which is a rate based utility and they're having some interesting discussions with the Board and themselves as to how to go through that transition.

In dealing with that utility, Manitoba Hydro, for a long time now, the issues of trying to increase its debt equity in order to be a little bit more secure, and the issues of financial soundness have always been there, and if I read your legislation correctly they're very much have been in your jurisdiction before and after the changes, and I took it from reading the application and I take it from having listened or read some of the evidence, that it's still very much an issue, as to what level of debt and equity, what level of return, what level of interest coverage, whatever you want to say, is sufficient to protect the financial soundness of the company to achieve and maintain a sound credit in the financial markets of the world, if you like.

So I know that in the jurisdiction of the Yukon, when the Yukon Energy Corporation was established by the Yukon Government by purchasing the assets and undertakings of the Northern Canada Power Commission, at the outset it was established and funded with a 60/40 debt equity ratio and when it first appeared before the Yukon Utility Board there was a directive form the government, as a matter of policy pursuant to that legislation, so it sounded very clearly that the government was directing the utility and the utility board that it wanted, and I don't remember the exact words, but it wanted for the sake of not being precise, a commercial return on the equity of that company, notwithstanding the fact that it wasn't a privately owned utility, and that was amended as time went on to say that type of return, less half a point. I wouldn't want to get into the history of that one, but the point was that it wasn't a matter of debate or doubt, it was a matter of direction and I'm wondering in this case whether one really knows for sure what is required in the absence of such a similar direction. Other than that, I wouldn't focus on much more than what's already written there, in terms of that section.

MR. HUTCHINGS: Okay, so those are the principal issues that arise under the heading of the revenue requirement. The next section of your evidence deals with cost of service and rate design and perhaps you could briefly summarize the points that came to your attention there as issues that needed to be dealt with.

MR. OLSER: Well, I think, rather than dwell on this section of the August testimony, it might be, I may well jump to the September testimony and come back to the next section, in light of the hour. The September 12th testimony dealt fundamentally with the issues in this area, given the cost of service and rate design matters required some more information than we had in August, so if I go to page 2 of the September testimony, a broad overview was provided of the rate changes, the tables, the page there is now out of date, if we had more time I'd give you the changes, but I frankly think you could spend the time, you could put in the changes that come from Mr. Hamilton's evidence and Mr. Osmond's evidence. Just to give the key ones, the NP base rate is now 6.4 percent, its RSP number is 6.7 percent and the overall is about 13.1, rather than 6.7, 5.9 and 12.6. The industrials rather than being 10.4, is now 10.0, the RSP is 6.1 and the overall is 16.1.

There is a summary there with a footnote on the various rate changes and I think as your discussion with Mr. Hamilton indicates the non-firm rate percentage is very sensitive to whatever load forecast the customers are giving to the Corporation. So I mean it changes depending on what forecast they're providing. You've reviewed with others, Mr. Hamilton I think, the expected rate changes. After we had gone through all of this we did sit down to look at these numbers and say what would one have expected if you went back and looked at the situation. Is this what you would expect to have emerged, and the conclusion I came to was no, and the reasons for that are laid out on page 3 and subsequent pages, focusing on factors that were there from 1992 versus the 2000 test year, the three key ones being the rural deficit as reflected in the NP rates would be a new change that would tend to put upward pressure on NP, Newfoundland Power; secondly, the interest coverage and margin of equity, to the best of our knowledge, the rates that were in place reflected a higher interest coverage for the industrials than would be the case for the rates as proposed; and thirdly, the cost of service methodology in moving from what you'd call interim to what you call generic or proposed. As we read the evidence available to us, that would lead to a significant reduction in the order of a million and a half dollars in the test year, in the industrial cost of service.

So those factors, it seemed to us, would tend to lead to a different result than what was emerging, and I just I thought it would be a useful question to pose, which I don't have any better answer for, frankly, than the time I wrote this as to why it came out differently. I don't think, in light of the time, we should dwell any more on that section.

Going to page 9 of the September testimony, we then focused on the cost of service and rate design issues as such, and again in light of the time, I think just to summarize, the very beginning of page 9 there is a very brief comment on what you would call principles. We are looking at an embedded cost approach. We are looking at something in this case that acknowledges the fundamental principles for rate design costing, relating to cost tracking, a fair apportionment of costs and also efficiency with respect to trying to give effective price signals, particularly, I suggest, when you're dealing with variable cost items such as fuel, so given that we all come to the table with these things in mind, what type of issues emerge and cost of service or allocation of a revenue requirement types of issues that emerge I dealt with first. I think, in general, the application and the material in it is generally consistent with the accepted utility practice in other jurisdictions. It seems to meet the bulk of the recommendations from the Board's 1993 cost of service report and to accurately track cost to the Hydro system and the customer classes to which it relates, costs relate with a few exceptions, and items where debate seems to be merited and I identified the new non-grid issues relating to that particular allocation issue, the Great Northern Peninsula issue, which is addressed in this material, September, in Section 5. I identified a discussion which has been going on about 2-CP allocated for generation demand related costs which is addressed in section 3.4. What I call dispatchable reductions in demand and you've been discussing it with various people in your questions, relating to on the one hand the Interruptible B that is a contract with one of the customers, and on the other hand the treatment of credit for Newfoundland Power's generation. That matter is addressed in section 3.5 of this material.

(4:15 p.m.)

The rural deficit, the design of the subsidy allocation and the issues arising from it, Section 3.6; frequency converters Section 3.7. I thought there was some additional issues arising from some of the intervenor expert testimony, classification of transmission plant as energy is one and that's in Section 3.8. Classification of non-utility generation and industrial purchases as demand and energy, Section 3.9, and finally some rate design matters, one you've been talking about of some length, the use of the energy only rate for Newfoundland Power, and the inclusion of non-grid transmission expenses in the establishment of the wheeling rate. I did say at the bottom of page 12 that the conclusion I came to was that we really were not trying to redo what you had done in 1993, and the overall, I would recommend an overall approach with caution towards trying to do overhauls from that particular report process, but there were some issues outstanding and some new ones that have arisen.

MR. HUTCHINGS: So the basic position was that the large cost of service issues had essentially been decided in 1993 and there were a number of residual issues that had arisen in the meantime or needed clarification.

MR. OLSER: Right, and some of them arise because of the changes in the framework and the context. Some of them arise because industrials are no longer bearing the, directed not to be bearing the cost of the rural deficit. Some of them arise because this whole process, as an integrated process, is now regulated by this Board, so that issues that might not have been there before have to be addressed. We reviewed cost characteristics because I think those can be important, and the interconnection versus non-interconnected systems, on pages 13, top of 14. Again, in light of the time, I won't dwell on it, but from experience in other jurisdictions of this type, especially in the Yukon, I can, I think there are issues that arise as to how you address some of these matters, so I'm open to discussion on that. The only other thing I would, rather than identifying, I'm sure, which everybody to the extent of their interest asked questions about the various issues, the one I'd like to, just to make sure is up to date is the matter of the ... 3.5, starting at page 17, of dispatchable reductions in demand. Since this has been written there has been an answer to a question IC-251, which, if you like, provided the type of analysis that we thought would be helpful and therefore cut through, if you like, our attempted to try and analyze this absent such information *(phonetic)*. That information essentially pulls together the impact of the credit and removes it from the current cost of service for the test year. The impact of removing the credit's impact, if you like, affects all of the things that we talked about in this evidence. It affects the allocators used for allocating 2-CP and it affects the system load factor used for classifying demand and energy for the purposes of the generation. The effect of that, the analysis in that particular answer says is to, you had questions on it, to effectively decrease, it's about a $1.3 million impact is what it shows to the effect of removing, to Newfoundland Power. Effectively, if you took it out of the application the way it is right now you would increase the cost to Newfoundland Power by $1.37 million and you've reduced the cost to the industrials by about $1.2 million. But I think you have to note that that really takes you to a point, if we could call a, we took the impact of that out of the situation, we haven't put anything back in, such as an interruptible rate for Newfoundland Power, okay, and I think there are various ways you could do that, but just to give a point, a focal point for discussion. The interruptible rate offered at the moment to the industrial customer (inaudible) megawatts is about $28.00 a year per kilowatt. If the 78 megawatts that are assumed to be a credit to Newfoundland Power would have provided at that price, it would a cost to the application of about $2.2 million. You would then assign that cost to the parties pursuant to the methodology. You would automatically have the type of load factor assignment that we were saying is relevant, and the impact in the end would be still some reduction to the industrial rate and some increase to Newfoundland Power assignment. There are other ways you could do the same thing. An alternative way of talking about it, is simply to say if the industrials paid the same amount as they paid in the application, how much of a credit would that imply to Newfoundland Power. How does that compare with the credit that the industrial customer is getting for offering interruptible power. Our assessment of that was that it would end up being a credit worth over $100 a kilowatt, which is a lot more than is being paid to the industrial customers. So our point was that there is an issue here of consistency, transparency, etcetera, and that we're moving down the road of dealing with it, but it doesn't complete it by the answer to that question. I think that's all I would deal with on that.

MR. HUTCHINGS: Okay, so the answer to the question basically gives some more specific numbers than the ones that you are able to generate at the time of writing your evidence

MR. OLSER: Right, it would effectively provide numbers to the last sentence of that section, as distinct from numbers we estimated.

MR. HUTCHINGS: Okay.

MR. NOSEWORTHY, CHAIRMAN: Excuse me, Mr. Osler, what would that question, what reference number would that question be?

MR. OLSER: That question was IC-251.

MR. NOSEWORTHY, CHAIRMAN: 251, thank you, sir.

MR. OLSER: 251(e) to be precise.

MR. NOSEWORTHY, CHAIRMAN: Thank you.

MR. HUTCHINGS: Okay, alright I think that takes us back then to Section 6 of your original evidence. You dealt with the revenue requirement issues, or the cost of service and rate design issues from Section 6 of the original evidence and you took us through those issues as they are laid out in the September evidence. Briefly then the next heading in the original evidence is 7, the Rate Stabilization Plan and that also, I think, is dealt with in both of your supplementary pieces of evidence?

MR. OLSER: Right, so to deal with that one from respect of the August evidence very broadly stated in the first page there that the whole concept or rate stabilization as applied in other similar jurisdictions ... my view, that it is indeed relevant and appropriate when properly conducted, particularly in systems that are not interconnected. The issues that arise though in this instance, because unlike the experience I've seen elsewhere, the other systems are designed to not just to stabilize, but to smooth out fluctuations and go to where we got to go to. I've never seen a system designed under regulation as distinct from under subsidy, where you would deliberately not at the time you've set down the next package, design it to move towards where you expect the price of oil to be, and the other fundamental feature that I found distinctive was the introduction of a load component in the RSP. So those matters were commented on in August, but not dwelt on.

MR. HUTCHINGS: Okay, but the first of those items relates to the notion of putting $20.00 in the RSP as opposed to $28.00 in the proposal.

MR. OLSER: Or any other number that you think is where the oil is going, but when the application says we don't think it's going to $20.00, but we want to put the plan to $20.00. That is not my experience elsewhere.

MR. HUTCHINGS: So okay, that's where you were with that in August, and how did time treat you with respect to the RSP?

MR. OLSER: Punishingly but essentially the evidence in Section 4, I think it is, of the September evidence, dealt with a more considered review of that issue, those issues. We did not have adequate enough information on the historical material up to the test year to comment on it in any depth, but we did deal with the, under Section 4.2 and following, on page 33, we did deal with the matters for the go-forward plan and essentially we thought we could work through the plan by that stage, given the answers we received, it seemed to boil down to, as you have said, loads used to allocate various accounts, the process of dealing with the hydraulic and the price variance, and the load variance and then the process of reallocating the rural deficit between those parties to whom it would still be applied. On page 34, looking at some of the questions we had answered, you could see how on a go-forward basis they would integrate the Granite Canal into this process, how they would deal with fuel price changes relative to the forecast and how they would deal with load variance in the next several years, and so all of these things helped to give clarity to, at least, how the mechanics would work through and to emphasize the extent to which you're creating a plan that has all these elements to it. On page 35 we summarized some of the answers we got on the impact of different oil prices, just to clarify that top table, or to explain it, at various ... the forecast price for fuel in various dates as put into the answer we received is shown there in Canadian dollars at $28.43 in the year 2002, going all the way down to $23.24 forecast in 2005. What is the impact on the RSP balance if the base price put into the plan in the test year is the $20.00 as applied for, which in the mechanics of the plant translates to $21.20 per barrel, or if you had a higher one or a lower one, $25.00 or $15.00, so it shows you that in the year 2002 you have a variance on the fuel price only, this is not the hydraulic and not the load, $25 million under one option. If you have $25.00 fuel price as your base, it would only be $10 million, if you had a $15.00 fuel price it would be almost $41 million, and it just traces through on a year-by-year basis what the impact is. Down below is a summary when you put together all of the accounts, the price, the hydraulic, and the load, what happens if you adopt a different base price for oil, and it just shows you the numbers of the impact on the account. Given the time of day, I think I'll leave it at that. Those are questions we thought would be relevant to summarize, comes from various answers to various questions. Obviously, it doesn't tell you, you've got to remember, if you jump the price up to $25.00 per barrel, you may help the RSP, but you will have a few customers that will notice it. It will affect rates, so that's the trade-off to be dealt with.

Going forward from there in this section, we dealt with the comments on the RSP approach. We provided comments in terms of what we thought of the approach and effectively raised certain issues. On the load variance, I'm not persuaded that that is a good thing to continue with and it was dealt with in more detail, if you like, in an answer to Newfoundland Hydro in No. 99. The fuel price variance, yes, it makes sense to have a plan to deal with fuel price, but there many different ways to look at doing it to make it more current or to plan for it to get to where you want to get to. And finally the concept of caps, I wasn't persuaded that it was necessary to change the cap, if the cap's only role is to bring you before the Board to get it dealt with. And finally, I guess I could add to all of this, one might look at recovery mechanisms as the thing from the discounted, declining balance method, you might look at other ones. But essentially my testimony is that there's a role for RSPs, there's a need to look at options and implications very carefully and there are certain items that I think merit discussion.

MR. HUTCHINGS: Okay, your second supplementary evidence as well deals with the RSP and perhaps you can very briefly give us the thrust of that while we're on the subject of the RSP generally.

MR. OLSER: The November 25th supplementary dealt entirely with the RSP, trying to understand the RSP up till this point in time. It has an attachment that works through the month of December 2000 in some detail for those who would like to share with us the experience of learning about it. I agree with the fundamental evidence that's been offered that the complicated issue relates primarily to the allocation mechanisms between the customer classes, and that's the one that took us the longest to find out, and it is because they used the AED, average and excess demand method on an ongoing basis to do this allocation which is a fairly complex assignment. My testimony in pages three and four focuses on elements of what was going on. I guess the load variation certainly has protected Hydro from the various errors or changes in load forecast. It has also though kept in the forecast companies that no longer exist in this jurisdiction, Albright & Wilson Americas and Royal Oak Mines, as customers of Hydro, continue to be assigned to the industrial class and I do not think, looking at line 19, page 4, there appears to be any basis to operate the RSP assuming the continuation of customers that no longer exist. Reviewing the allocation mechanisms to make customer groups, which is really what we're doing here, Newfoundland Power and the industrial group, there's a summary bottom of page 4, top of page 5, of the key issues that arise from effectively continuing to apply matters that do not flow from fuel, namely demand adjustments, capacity adjustments, load adjustments on the capacity side into what is supposed to be a fuel energy relating RSP mechanism. I think the results historically have been inappropriate and the change the company is proposing to use only energy in the future is appropriate and provides a test of fairness to assess how reasonable it has been with changes to date.

The allocation of the rural deficit has continued to be an issue in the allocation formula, and frankly, one of the last items that we could understand in this process. Now the industrial customers are not assigned this any longer and the adjustments have been made in the course of this year, after, beginning of 2000, but it's still an issue for all the other years before that and it seems to have merit, to be reviewed on its own merit and I know the industrial customers have raised issues about phasing down of the rural deficit in the time period leading up to the year 2000. In summary we reviewed, on pages 6 and 7, the apparent initial intent based on material recently filed by the

Corporation in a letter that has been found from the mid-1980's that quite clearly, I guess, laid out at that time certain mechanisms. I think in principle, the conclusion I reached is I looked at the 1985 Board order, I looked at what's happened in practice, I don't think that it was necessarily understood the extent to which the RSP would in fact deal with load variations. It had nothing to do with the earnings of the company, namely demand and capacity. I don't think ...

MR. HUTCHINGS: It's the 1985 order?

MR. OLSER: Yeah, well the '85 decision and the framework. As far as I can determine we're working with a mechanism that was put together then and not substantively reassessed until now, and I'm not sure that anybody understood that it would be as un-transparent or as difficult to deal with, when you have to go back and look at it so many years later. The basic recommendations on the final page, just to cut through all of the details, in order to address the significant inconsistencies, and in my view, improper operation for the reasons I've given you of the RSP, since the Board last reviewed Hydro in '92, I suggest it is necessary to recalculate and restated the RSP back to '92 making certain adjustments, namely do not allocate production demand or transmission demand related cost between the various customer groups since these have nothing to do with energy, and nothing to do with changes in the earnings of the company; two, remove Albright & Wilson Americas and Royal Oak Mines from the load forecast for all the months they've been disconnected; and three, assign a rural deficit based on a PUB rural deficit allocation ratio form the '92 cost of service rather than recalculating the process and address any other issues that relate to the industrials when you're doing that.

MR. HUTCHINGS: I note, Mr. Chair, we've gone over the usual closing time. If we had probably five or ten minutes more we could probably complete the direct. I'm in your hands.

MR. NOSEWORTHY, CHAIRMAN: I think we've allowed for some flexibility here. We said if there's a completion, a satisfactory completion that would end between 4:30 and 5:00, we're prepared to move on, so if you will be completed in 10 minutes or so, that will be fine.

MR. HUTCHINGS: That's fine, thank you, Mr. Chair. I think, Mr. Osler, we've gotten to the point of reviewing the August 15th evidence, and the parts of the subsequent evidence that deal specifically with the issues that are raised there. If you could just briefly then in turning to your September 12th evidence, I know you've reviewed parts of this already, but just confirm for us the focus of that evidence and highlight any of the other sections that have not already been spoken to.

MR. OSLER: The only matter we haven't spoken to in this process has been Section 5 of the September 12th evidence dealing with, starting at page 37, dealing with issues to do with the interconnections to the island system, which was a final section of that evidence. It was an issue that grew in volume and significance, it seemed, as we worked on it, so we gave it a separate section all of its own. The, excuse me, there is a lot of material filed here, and there's been more material filed since it was written by Mr. Budgell. I think the issues are still there on the table, and I'd like to just clarify and make sure that at least the intent of what I'm saying is as clear as possible.

This has been a major change since the last time rates were set. You've connected people to the main system that weren't connected before, and it does raise several interesting issues, and it does affect your revenue requirement and your cost of service allocations, so the issues that arise from your previous orders and from just common sense are how prudent was this project, in light of regulatory principles and practices, if you like, and anything else you want to throw on the table. Assuming that it is prudent, a second question is cost of service treatment of prudent costs because it will raise issues as to the fair treatment of different customers, and it raises these issues regardless of the legislated changes since the last time you sat, but in particular, given the legislative direction to not make rural deficit costs assignable to industrial customers. There's an underlying, overlying question here about how to make sure that one doesn't do indirectly what you're not allowed to directly, so it poses some interesting challenges.

We tried to address both of the two questions separately, and pages 38 and 39 summarize an assessment of prudence that takes up most of the rest of the attached material including some appendices. There is also an assessment of allocation of costs assuming that they are prudent, so both issues are addressed, and I'll just deal with the summary. In terms of assessing the prudence, two key perspectives that need to be assessed, I think, and with the onus on Hydro being to satisfy the tests, are first of all the overall utility financial cost implications of the project. Does it, in fact, result in lower overall utility costs than would be the case if you hadn't done the interconnection. In looking at that issue our review as written in this testimony indicated concerns with respect to insufficient consideration to alternatives, what appeared to be material errors or omissions in some of the financial and cost assessments, in the sense that some material that was identified to be important didn't seem to be utilized in the 1994 work, and the test itself of if it can meet 25 years on the assumptions set there that that would be a good indicator, and we had some concerns about that test being applied in this instance.

Our conclusion was that at best it seemed to be a very marginal project, close to the bone, if you like, and it may be, it could be possible that a thorough investigation would indicate that substantial portions of the costs should be disallowed as being imprudent, but we have no ability, given the information base that's there, to decide or offer further comment as to quantity. In order to do that you would need a lot more information, none of which was asked and not offered.

A further prudence issue, I would also look at rate and revenue requirement implications as well in the sense that it's not, in the practice I've seen people looking at this, they don't just look at the overall cost and cash flows, they tend to look at the implications to ratepayers by working through the two alternatives to show how ratepayers would be affected, how the costs actually flow into rates over the ten or fifteen year time periods to see what issues might arise in a rate context. I didn't see evidence that that had been done and that caused concern. I would have thought it would be relevant if you had to review it before a Board to have that type of information.

So in terms of trying to grapple with the prudence question, my key conclusion at the top of page 40 was, I recommended that for this particular project at least Hydro be required in the current hearing to provide an analysis needed for the Board to address each of these above issues.

On the cost of service treatment, assuming that we do have prudent assets, prudently acquired assets, there are some interesting issues, and they are addressed on page 40 under item two, and through the balance of this summary, and I guess to try and summarize it, there are certain facts that one should have in front of one. One of them is that the customers who used to be on the isolated system have received a substantive reduction in their rates. They're paying, we gather, some $3 million or so less now than they would have paid before because their rates automatically reduced when they went on the interconnected system. So if you have a marginal project, the point is that when you finish the project, the ratepayers paying money, you've just given back a bunch of money to one group of them, which raises questions, I would think, automatically for the people that were on the system before as to what's going to happen to them.

Then you get into the assignment issue and, of course, the Board has been seized, and everybody has been seized with do we call these common or not, and is the test, is there substantial benefit to more than a few customers, one customer. What does substantial mean, etcetera. My conclusion was that the evidence in the current hearing confirms that the development with the transmission costs assigned to common, which in the original situation meant that the industrials share in the assigned costs, increases the 2002 costs charged to the island industrial class by about three percent, or about $1.5 million in the test year, compared to what would occur if these costs were not assigned, were assigned to rural as in the 1995 cost of service analysis, and the number by itself is open to a lot of debate because it comes from answers given by the Applicant.

I conclude that there is no evidence that the industrial customers get any benefit from this that would justify that type of an assignment, and that one should be looking very carefully at the rules therefore, in light of those facts.

The only type of benefit that's alleged they could get would be some generation benefit, and the evidence is that the only available access for the customers that were on the system before to generation benefits would be during the time periods when the system is not at its peak, during the load time periods, or the summary time periods, and frankly, given the amount of generation capability on the island system, without access to anything on the GNP system, there isn't an apparent need for such a benefit, so on an economic basis, it doesn't look as though there's any practical value to any theoretical benefit, and there certainly is a very material cost assigned if you treat it as common. So with those in mind, it struck me in conclusion that one should amend the ground rules to reflect the type of considerations I'm talking about rather than just trying to see whether a kilowatt hour, or a few kilowatt hours escape the system and become part of the main system, but get to something a little more substantive than that ... looking at whether you're dealing with, if you're in the key peak months of the year when it's of value, or any other evidence that can be offered that this can be translated into economic value rather than theoretical discussion. That would be eligible too, but we haven't had that, so in my mind it doesn't qualify as a common cost, and I think, although I didn't dwell on it, I didn't even raise it here frankly, but it struck me subsequently, regulators in the case of natural gas have had a similar issue, an analogous issue, in deciding when they would authorize expansion of service from the main systems to more rural customers, and they put tests more like five years on ... they want to see some ... we don't want to see the main customers being exposed to a whole bunch of costs beyond a very short time period, we want to see some benefits flowing to the main system. Tests like that in these contexts I think are relevant, not just overall economic tests of somehow does the thing make sense in 15 years.

Whether or not one agrees with me on that, it seems to me that the legislative intent in this jurisdiction, page 42, in the second paragraph, we do have an issue of the industrial customers being assigned costs that would have otherwise been rural deficit costs, and I think that is a very pertinent issue for this jurisdiction and this Board to address, and I cannot see a rationale that I could support as to why in this instance that isn't all that's really happening. And if that's the case, I think you have a legislative direction that that isn't what we're supposed to be doing here.

So based on the available information and including the relevant rural deficit impacts, I conclude that the specifically assigning the GNP, Great Northern Peninsula transmission assets to rural remains reasonable, even if the, even if the GNP generation is to be treated as common, and the detail of this testimony it says there could be a rationale for treating the generation as common, at least for the short term until certain things are addressed in terms of certain studies that the Board has requested have been addressed, without making a long-term determination, so I think ... there's a lot more detail in here but given the hour, I think that's where I would close.

MR. HUTCHINGS: Okay, I think with that then, Mr. Osler, we've reviewed the three pieces of testimony in their totality and we can leave it there. Those would be all my questions on direct examination for Mr. Osler, an we can commence with the cross in the morning, Mr. Chair.

COMMISSIONER SAUNDERS: I have one question if I might, Mr. Chair. Mr. Osler, I'm wondering if, and it may come from the fact that after you sit up here for a number of days, I think probably you get some lightheadedness, you know, from the lofty height, but have you discovered the cause of the aggravating uncalled for space that you have in your presentation?

MS. GREENE, Q.C.: We noticed that as well, Commissioner. I had to get my bifocal contacts changed.

MR. OSLER: I have not found the ... I suffer from the same problem when I get my copies of it, so I don't know what the reason is.

MR. HUTCHINGS: I think it's somewhere between P, D, and F, Commissioner Saunders.

MR. NOSEWORTHY, CHAIRMAN: Thank you, Mr. Hutchings and Mr. Osler, we'll reconvene at 9:30 in the morning with Hydro's cross-examination please. Thank you.

(hearing adjourned to November 30, 2001)