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November 13, 2003
(9:18 a.m.)
CHAIRMAN:
Q. Good morning, thank you. Apologize for the delay which was unavoidable. Good morning, Ms. Newman, is there any preliminary matters before we get started?
MS. NEWMAN:
Q. Yes, good morning Chair and Commissioners. I believe that counsel for Newfoundland Hydro would like to speak to a matter.
CHAIRMAN:
Q. Good morning, Ms. Greene.
GREENE, Q.C.:
Q. Good morning, Mr. Chair, Commissioners. At this time I would like to address the issue of the Rate Stabilization Plan and I am happy to report that the parties have reached agreement and are prepared today to submit to the Board for its review and consideration, proposed changes to the current rules for their Rate Stabilization Plan.
I have here a document that I would like to circulate at this time to the clerk. The parties have already been provided with

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copies. I don't intend to speak to the actual proposed changes in the Rate Stabilization Plan at this time. Hydro will be filing supplementary evidence from Mr. Banfield that will address the proposed changes that we are asking the Board to consider and to approve. However, I would like to point out that the Rate Stabilization Plan as proposed does contain the same four elements as currently the load component, the hydraulic component, the fuel component and the rural rate alteration component. However, there are changes to each of the elements with respect to how the balances will be assigned and collected.
The intent of filing this today is to-- before the experts start is to advise the Board that the parties have reached consent with respect to the proposed rules. And as I mentioned, we will be filing evidence through Mr. Banfield to explain what the changes are. So at this time I believe the document should be marked as a consent document.
MS. NEWMAN:
Q. Consent document, Consent No. 2.

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EXHIBIT ENTERED AND MARKED CONSENT NO. 2
GREENE, Q.C.:
Q. I also have--I should point out first that Consent No. 2 the document that just has been circulated are the proposed changes to the current rules that are existing in the rate schedules, but it doesn't address the issue of the recovery of the historic balances in the current plans. I call them the old plan where the balance was frozen as of August 2002 and the new plan which commenced on September 1.
The second document that I have to distribute outlines a proposed change with respect to the recovery of the historic plan balances. The second document is consented to by Hydro, the Consumer Advocate and Newfoundland Power. The Industrial Customers are taking no position on the second document. Hydro, the Consumer Advocate and Newfoundland Power have reached agreement to extend the recovery period for the new RSP from the current two years to four years. And this document sets out that proposal for the Board's consideration. This document would also need to be marked and as I mentioned it

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has been--and the parties can indicate, Newfoundland Hydro, the Consumer Advocate and Newfoundland Power are consenting to this document with respect to the recovery of the historic plan balances and the Industrial Customers are taking no position with respect to this issue.
MS. NEWMAN:
Q. I guess we could file it as an information item if Industrial Customers would rather not have it filed as a consent document.
HUTCHINGS, Q.C.:
Q. I have no problem with it being filed as a consent. I mean we can consent to the filing of the document.
MS. NEWMAN:
Q. Perfect.
HUTCHINGS, Q.C.:
Q. The contents of it, we take no position on.
MS. NEWMAN:
Q. Consent No. 3.
HUTCHINGS, Q.C.:
Q. We neither object nor consent.
EXHIBIT ENTERED AND MARKED CONSENT NO. 3

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GREENE, Q.C.:
Q. Mr. Chair, it is the party's position that the new rule should come into effect as of January 1, 2004 because as you know the Industrial rate adjustment starts in January. So even though there may not be an order arising with respect to the base rate increases, the parties have agreed that the proposed RSP rules, if acceptable to the Board, should commence on January 1 of 2004 and should apply to the Industrial adjustment that would flow in January. And rather than take time to go through each of the components now and explain them, I believe it's preferable that we will do that through a witness and that will be Mr. Banfield and we will pre-file supplementary evidence to explain the proposed changes in the plan that we are happy to say that all the parties have agreed to. And with respect to the recovery of the balances that three of the parties have agreed to and the other party has taken no position on at this time. Thank you.
CHAIRMAN:
Q. Thank you Ms. Greene, very much. We certainly look forward to the evidence on this and

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certainly in consideration of the matter, I would like to commend the parties. Once again, I think the work in terms of mediation, work in terms of agreement in principle on this is really quite commendable. It's a progress I think that we, in the course of a hearing, like to see the parties come together on, I think it moves things forward in a more efficient and streamlined fashion and the Panel looks forward to hearing the evidence and considering the matter further. Thank you very much.
Any other items, Ms. Newman?
MS. NEWMAN:
Q. No, Chair.
CHAIRMAN:
Q. Call upon Mr. Hutchings. Good morning, Mr. Hutchings, if you could introduce your witnesses, please.
HUTCHINGS, Q.C.:
Q. Good morning, Mr. Chair. Mr. Osler and Mr. Bowman have taken their places to give their evidence and we'd ask that they be sworn and we can then proceed.
CHAIRMAN:

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Q. Thank you very much. Good morning, gentlemen.
MR. CAMERON OSLER (SWORN)
MR. PATRICK BOWMAN (SWORN)
CHAIRMAN:
Q. I note, Mr. Browne, as well you have somebody joining you at the table, if you could probably care to introduce this gentleman.
BROWNE, Q.C.:
Q. This is Mr. Doug Bowman, you all know from his previous appearances here since 1996. He's joining us today.
CHAIRMAN:
Q. Good morning, Mr. Bowman, welcome sir. When you're ready with your direct, Mr. Hutchings, please.
HUTCHINGS, Q.C.:
Q. Thank you, Mr. Chair. Would you please initially state your names for the record?
MR. OSLER:
A. Cameron Osler.
MR. BOWMAN:
A. Patrick Bowman.
HUTCHINGS, Q.C.:
Q. Pre-filed evidence has been placed on the record in your names in this proceeding dated

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September 2, 2003. Do you adopt this document as your evidence for the purpose of this proceeding?
MR. OSLER:
A. I do.
MR. BOWMAN:
A. I do.
HUTCHINGS, Q.C.:
Q. Mr. Osler, does the resume, included as Attachment 1 to your evidence accurately present your professional qualifications and experience in the field of utility regulation and the other fields referred to in that resume?
MR. OSLER:
A. Yes.
HUTCHINGS, Q.C.:
Q. Mr. Bowman, does the resume included as Attachment B to your evidence accurately present your professional qualifications and experience in the fields of utility regulation and the other fields referred to therein?
MR. BOWMAN:
A. Yes.

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HUTCHINGS, Q.C.:
Q. Can you tell us initially how long InterGroup has been associated with the Industrial Customers of Newfoundland and Labrador Hydro and for what purpose?
MR. OSLER:
A. We became involved with the Industrial Customers in 2001 in the summer with respect to getting evidence prepared for the last hearing of this Board dealing with rates of this utility. Our involvement has been--it was through that hearing I gave evidence. We were involved recently when you started preparing for this particular hearing, as well as the Capital hearing I had earlier in the summer, I gather.
HUTCHINGS, Q.C.:
Q. Can you, for the convenience of counsel and others who may be asking questions, indicate to us initially as between you, the division of labour relative to this piece of evidence and the questions that maybe asked today?
MR. OSLER:
A. The overall evidence we prepared together but in terms of preparing for testimony today, I will deal with the overall context sections of the evidence which would be Sections 1 through 4. I'll deal with the revenue requirement comments in Section 5. Updates relating to that, Patrick Bowman will deal with because he's been involved with the detailed reviews that I haven't been able to deal with recently. Cost of Service, which is Section 6, I'll again set the context, in particular Section 6.1 and 6.2. Mr. Bowman will deal with the Cost of Service allocation issues from Section 6.3 through to the end of the Cost of Service, Section 6.6. And then the final section dealing with overall rate design issues, I will deal with that, although a lot of that section has now been addressed through the consents that have been filed today.

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HUTCHINGS, Q.C.:
Q. Thank you. Mr. Osler, then can you indicate for us initially the major issues of concern to the Industrial Customers arising out of the present General Rate Application?
MR. OSLER:
A. In our evidence in Section 2 we review the general interests of the Industrial Customers. The fundamental interest and concern relates to the level of the rate increases. As it's noted in that section at Page 5, the Industrial Customers who consume upwards of, I think 20 percent of the energy produced by this utility see a slight reduction in their forecast energy use but a significant increase of some 30 percent when they saw this application and the cost that they were to pay. So, the overall level and magnitude of the rate increases, of course, I'm aware is a compelling concern to them.

When you look at the factors that relate to that rate increase, they cover a number of different elements. They include the revenue requirements as such of the utility, not just the cost increases that come from some of the growth elements but other cost increases that relate to management controlled issues and also some policy issues relating to Rate of Return. Also, the rate increase is affected by cost allocation issues as between and among customer classes. It's affected by the firm rates and how they are set with those cost allocation issues and the Industrial Customers have a concern that they do not end up paying rural deficit contrary to the legislative directives. The cost allocation issues also carried over in the initial application to the RSP, the Rate Stabilization Plan and how that affects the outcomes as to how their actual consumption may vary from what's forecast in this rate application.

The rate increases are also affected by and the overall effect on the bottom line of some of these customers is affected by the removal of the Interruptible B as a rate option. Beyond the sort of immediate rate effects and the factors that explain them, the customers have an interest in the long run because as Industrial Customers that's their focus and there are a lot of issues arising with respect to how this particular hearing fits into that long run, how this particular Rate Application fits into that long run, where are we going, how do we get there, how do we manage the process, where is this hearing fitting compared to the last one and any ones in the future and there are a number of issues that are noted in here that relate

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MS. OSLER:
to that sort of thematics. In Sections 3 and 4 of our evidence we give an overview of the Hydro application and the context in which it is set, particularly noting the hearing that took place in 2001 and how it started the process of regulating this utility and saw, in the Board's words, have its own order coming out of it, that as a first step and saw a lot of interest in what's the second step and what are the future steps on that road.

HUTCHINGS, Q.C.:
Q. Can you advise the Board from your analysis what additional revenue Hydro is actually seeking to achieve by the rate increases proposed and what appears to be driving the increased revenue requirement?

(9:36 a.m.)

MR. OSLER:
A. Yes, and I'll turn to Section 5 starting at Page 13 in doing this. I will address it in the context of our evidence as filed and then Mr. Bowman will comment in terms of the updates that have recently been provided to the participants.

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In general, the overall application talked about an increase of some 55 million dollars over the approved 2002 test year revenue requirement. This 55 million dollars though isn't all to do with a rate increase, because some of that increase in revenue from the 2002 test year revenue requirement occurred simply because of growth and increased revenue from--due to charging the growth at the current rates. So when we were focusing on our analysis on this, we focused on that segment of the system relevant to our customers, namely the Island Interconnected section. And at page 14, Table 5.1, we summarize the type of effects, the 2002 final revenue requirement test year and the 2004 proposed for that portion of the system, the Island Interconnected and the bottom line there, is that although the revenue requirement increase is 50.9 million in the application, the actual increase to do with rate increases proposed in this application of that was some 39.7 million.

The analysis as to why that increase which is some 13 percent measured against the

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base, why that increase is there is the subject of this section of the evidence. At Page 13 in particular, it's sort of summarized. The applicant has stated that the primary factor explaining this increase is the new generation purchase power costs and the Granite Canal, the increase in these new facilities or these new agreements.

Our analysis is that these factors account for some 15 percent of the rate revenue increase that we just referred to and a further 35 percent of this total increase relates to increases in fuel prices and other factors relating to purchased power. So then in summary, about 50 percent of the overall increase for the Island Interconnected does not relate in any way to Granite Canal, the new purchase power agreement or the cost to supply load growth since 2002 or indeed to any other fuel cost or purchase power factors. It relates to a number of other factors which we've analyzed which are factors relating to the cost of the company and the escalations relating thereto, or the cost of equity relating to the policy proposals in this

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application to shift from a 3 percent return to a 9.75 percent return, on equity.

The analysis that sort of explains this is at pages 16 and the Table 5.2 at page 17 and I'll just summarize it very briefly. If we look at Granite Canal effectively, in service of Granite Canal by 2004 results in an increase in energy being produced by hydraulic generation, rather than Holyrood. The construction of this facility resulted in test year costs of some 11.8 million return on equity and debt and new hydraulic O&M. But it also saved some 10.48 million of Holyrood fuel and something around one million of Holyrood variable O&M. Hydro has also proposed to remove or eliminate the Interruptible B program as a result of this new generation, which results in a further saving of 1.297 million in purchased power costs. So the overall net effect, based on the original application as filed, of the Granite Canal in our analysis is a saving of some .95 million per year in the test year. Similarly, that type of approach taken with the Purchase Power Agreements shows a net increase of about 6.2

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MR. OSLER:

million dollars. And looking at load growth itself, if we were to supply that load growth with Holyrood it would cost some 13 million dollars. But if we look at the revenue you can collect from that load growth at existing rates, it's about 12.3 million. So the net effect is about .71 million. That's all at Page 16.

Page 17 the actual table summarizes those points in the table showing the overall change to revenue requirement for the Island Interconnected as we go from one year to the next year, 2002 approved versus 2004 revenue requirement proposed in the application as filed. And you see there a difference of some 52 million dollars but 12.3 of it is accounted for by load growth and revenue at existing rates. So the net increase due to rates proposal is about 39.7 million. And columns D and E talk about the Granite Canal effects with a negative .94 effect as you can see by looking at the two bottom columns, two bottom rows at row 15, for columns D and E. The analysis for purchase power agreements is

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similarly at columns F and G and the load growth effects at H and I. So the overall effect is that some 5.959 million of the 39.7 million increase due to rates is due to those three factors; Granite Canal, purchase power agreements and load growth which is 15 percent of the total, as I said a few minutes ago. The balance, 85 percent is due to other factors. The other factors are reviewed at Pages 18 and 19 and I've summarized them already. So that sort of is the world as we saw it. At the time reviewing the application I'd ask Mr. Bowman if he could just sort of tell us the extent to which this picture has materially changed or not changed as a result of the updates.

MR. BOWMAN:

A. The information filed October 31st updates a number of the revenue requirement items as well as the loads, so it changes the assumed revenue at existing rates to a small degree, looking at Table 5.1 specifically at page 14. For 2004 proposed, it had said that the revenue requirement calculated by the Cost of Service for the Island Interconnected system

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had been 327.9 million with a total amount to be collected by rates charged to Island Interconnected customers at 345.3 million. Revenue at existing rates at 305 is there to leave a shortfall of about 39.7 million. Those numbers have updated slightly. The net effect was a reduction in the revenue requirement of some 4 million dollars such that it's now more in the order of 323.6 million. The rural deficit and revenue credits have not changed materially but the revenue to be collected through rates therefore is down again by slightly over four million dollars to 340.8 million. And that number would come from the revised Banfield evidence. Revenues at approved 2002 rates are now set at 305.9 million so the shortfall instead of being closer to 40 million is now 34.9, 35 million range. Measured on the base revenues at existing rates of 340 million the increase is now somewhat less than had been in there before, it's slightly over ten percent. It's not possible with the information that's filed to do a full update of table 5.2 and it would be a bit of an exercise to go through

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that now but the significant conclusions within that haven't changed to the extent that a few of the line items have changed. The drivers of the rate change in regards to number 6 fuel and depreciation are somewhat lower than had been before and the driver of the rate change in regards to general operating maintenance and administration costs are somewhat higher by about $200,000. So then instead of the O M & A, the top line, row 1, column K which had been listed there at 5.4 million, that's now about 5.6 million. While number 6 fuel has come down by some 000, and depreciation has come down by some 200,000, the overall conclusions are not materially different.

MR. OSLER:

A. The one thing I'd add at the end is that all of this does not include some things. It does not include, as noted at page 14, any change to the method of the assumptions used to include the hydraulic energy at lines 14 through 18 at this point is noted. There's about 5.97 million dollars in costs, largely related to fuel that would arise if the Board

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MR. OSLER:
had, and the applicant had adopted for this purpose, the Acres recommendations regarding long-term normal hydraulic plant output rather than a 30-year period assumed. We note that if you were shifting from the 30-year period as we saw it in the 2001 application and final decisions, through to the Acres long-term numbers that we see in this evidence, that this application itself though because of just reductions in the 30-year numbers has already moved about one-third of the direction in the distance towards this type of an objective of a long-term normal hydraulic output as per the Acres report. But that's still a fairly material distance left to go is the 5.97 million and indicates--and that would be the type of thing that one would like to--one might have concerns about in terms of where are we going and when will this type of effect take effect. So that's not in these numbers but it's a sign on the road that says there's a bump coming.

HUTCHINGS, Q.C.:
Q. Moving on then to Section 5.2 of your

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evidence. You have some discussion there on the issue of return on equity. Perhaps you could indicate for the Board whether from what you've seen in your analysis of this application and the evidence filed in support of it, there is at the present time any statutory or evidentiary foundation for regulating Newfoundland and Labrador Hydro in the manner similar to an investor owned utility.

MR. OSLER:
A. In summary, no, we've not--I testified in the last hearing that we didn't see any basis on either legislative or evidentiary information for taking an investor owned approach to setting the return on equity. And our evidence, Section 5.2 starting at Page 19 simply reviews what we said and the Board said, coming out of the last hearing and really notes that there has been no material change from what we were saying or what the Board was looking for. If anything, the issues with respect to achieving a financial target and a financial plan don't seem to have been any more resolved than they were a couple

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of years ago or have we moved any closer than we were talking about then to some of the targets such as an 80/20 debt equity ratio.

Meanwhile, the guarantee fees continue to be paid to the government with respect to the debt. The financial security and the sound credit rating matters with the legislation and the Board both noted, continue to be seemingly addressed. So on all those reasons we don't see any rationale for progressing towards an investor owned Rate of Return at this time or this hearing for this utility.

HUTCHINGS, Q.C.:
Q. Moving on then to Section 6 of your evidence. This deals with a number of Cost of Service issues. Can you just initially outline what purposes this Cost of Service Study should serve and what concerns are raised from the point of view Industrial Customers and the manner in which the Cost of Service Study is proposed to be implemented in this hearing?

(9:48 p.m.)

MR. OSLER:
A. What I've just been referring to in terms of revenue requirement issues are not

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specifically the sole interest of Industrial Customers, they're presumably the interest of all customers. As we move into the Cost of Service issues though, we now start to talk about cost allocation matters as to how we take the revenue requirement, whatever maybe approved and to sign it and allocate it among customer classes. So the fundamental principles involved are fair and equitable assignment or allocation principles. And the fundamental interest of the Industrial class or the extent to which that is in fact has been achieved or other issues arising from some of the allocation matters that cause them concern.

In terms of sort of setting the stage for it, Page 25, 26 we reviewed the relative changes in rates emerging from the initial application as filed. These changes in rates were provided by the applicant based on the revenue requirement just talking about but they did not include all of the cost allocations that seemed to be in the discussion. The Cost of Service analysis, for example, that the applicant filed does not

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MR. OSLER:
include assigning the Great Northern Peninsula, the GNP, generation in the manner that the applicant is now proposing. So there are things that are in this that--there are things that are talked about that we will talk about that are not necessarily reflected in these numbers. But what the information at Table 6.1 and 6.2 showed was that from the point of view of Industrial or other customers, they are the rates that emerged from this hearing in terms of firm rates and the increase is 12 to 13 percent of the type we've just been talking about. And there also are the increases in cost to customers that occurred from the RSP which is also approved as a rate form in essence and has an effect on customers to do with the outcomes of the situation both respect to fuel and respect to hydraulic and in the way it was put into the application initially, the load variations from what was necessarily forecast here. So the overall increase isn't just affected by the firm rates we're talking about here. It's affected by the RSP. In fact, the application

Page 26

that's filed, the major effects or the largest share of the effects on the Industrial Customer group was coming from the RSP as shown in Table 6.1.

I would note that the percentages used in our table are calculated a little bit differently than the way some other people use these percentages. They're calculated against an overall base of costs, both RSP and otherwise that the customers face in the base year. So the percentages are slightly lower than you typically see. We show a 12. 0 percent firm rate increase for Industrial Customers with the applicant looking just at firm rates alone and not firm rates against the base of firm less RSP showed 13-1/ 2 percent. The numbers are equivalent, they're just using a different base. They're not talking about a different type of cost in terms of a firm rate increase. In terms of updates, these numbers have all changed slightly as the applicant has noted rather than a 13.5 percent firm rate increase, using their numbers, it's now 12.2, given the changes that have been recently updated. So

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these numbers have changed both in terms of the firm rates and of course the consent, the material filed today has a material impact on the RSP numbers that you see on these two pages and elsewhere on this material. It changes the RSP principles and approach such that the effects that we were concerned about in this evidence are significantly moderated and then the allocation over four years of the Consent No. 3 again spreads the effect of RSP recoveries over a longer time period which again moderates the effects that you see in this evidence.

In table 6.2 looking at the material as originally filed, we had shown the trend line for rate increases overall, RSP and firm, not just for the test year 2004 but as far as we could see from the evidence, for the next three years. And we raised a concern that there was a big bump for Industrial Customers of some 28 percent in the initial test year with a slight increase the next year but then a 10.8 percent reduction from the numbers in the application in the next year. This seemed to be an unstable type of a rate future and

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not one that one would normally want to see happening. I'm advised that looking at the effect of the updates, particularly with respect to the RSP in Consents 2 and 3 today that this type of effect is significantly changed. I wait for the evidence to be filed by others as to the hard numbers, but my understanding is that rather than seeing this up and then down, you will see an up that stays very stable.

The questions that then still remain are if you've having an increase of that nature, should it all be pushed into the beginning, should it be spread out over time, where are we going, why are we doing this today rather than gradually smoothing it in over time. But the particular things that we talked about here which were largely derived from the RSP on page 26 have, I believe and understand to have been addressed materially in the two consents filed today.

The other element of sort of context setting here is pages 27 and 28, the supply conditions. The last time we had a hearing on these matters the utility's evidence was that

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MR. OSLER:
there was a shortfall in its capacity relative to its load. The evidence in this hearing is that with the new facilities, Granite Canal and the new purchase power agreements, there is not a shortfall and in technical terms there's more capability than there is a need in order to meet the criteria. That's laid out in Table 6.3 and the criteria I'm talking about are the loss of LOLH. You can see that the number of years needed to a next plant being required are five years in the 2002 test year and 2004 test year it was six years either being required or planned. Nowadays we're talking about not needing new requirements until after 2010, 2011 type of time period. This is a material shift in situation. It comes together with the fact that the last rate hearing was a first step in the regulatory process for this utility. It opened, both of these factors opened the door to dealing with some of these cost allocation issues today in a way that wasn't possible before or in a way which the Board simply said the decisions they had put on the table before

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were interim and now the time comes to make them final with some of these cost allocation issues.

In terms of actual rate setting and Cost of Service issues, the surplus that I've just referred to has had only, as far as we can see, one material impact on the application, and that is the removal of interruptible B, a contract opportunity with Abitibi Stephenville. And we will address that. An interesting question is the extent to which that is a short-term measure that is not consistent with long-term interests, or alternatively, are there other short-term or other longer term interest measures that should be addressed in this Application similarly flowing from the change in capacity relative to requirements.

So those are two context setting issues in terms of the RSP and the update to do with that and the situation respecting capacity and supply and requirements. But, overall, looking at the allocations, Cost of Service allocations, we're looking at those principals I talked about and the allocation of the cost

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as among the customer classes.

Q. Do you want to deal now with some of the specific Cost of Service issues that are of particular concern to the Industrial Customers?

MR. OSLER:

A. Mr. Bowman will go through the specifics from the Application, the issues arising there from and the Cost of Service Study in it. I'll just make one comment though because of some other evidence has been filed since then from EES which raises again the questions that we thought were put to bed with respect to the GNP transmission allocation.

Pages 31 and 32 we did review the background from the last hearing on this matter. In the 2001 proceeding Hydro had proposed that any radial transmission line that had generation in place as well as the cost of the generation itself should be allocated to all Island Interconnected Customers as being of common benefit so long as the generation could, even what we talked about as light load conditions, that is not the time of the system peak is at issue or the

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summertime specifically exceed the radial load. The Industrial Customers disagreed and the evidence that I provided addressed that, and that's at the top of page 32. We said there was no basis to assign a transmission line as being of common benefit if the generation could only exceed the radial load under such conditions, light conditions of load such as summer conditions and that generation was not simply required on the main grid. And we also raised questions about the pudency of that particular capital cost. We indicated from the evidence that a proper project review would have addressed issues to do with pudency. And the Board, in effect, didn't really get into that in its order, but did determine that Hydro's proposal to classify the GNP transmission and generation as being of common benefit was not acceptable at that time. It asked and required Hydro to do a study, which it did, and it's been filed in this hearing as Exhibit JRH-3. So, that study confirmed with respect to the GNP assets that the GNP transmission is not of any common benefit to the Island Interconnected grid and

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MR. OSLER:

so Hydro has determined it is appropriate to retain the transmission line itself as specifically assigned Rural. And that's sort of, I think, a significant part of story where we thought we'd got to the end of it.

EES has looked at this and said, not having been--had the privilege of sitting through the 2001 hearing, I guess, they noticed an inconsistency in the Hydro material because it was removing the transmission from being common, as the EES sort of saw it, but it was going to propose that we put the generation in as being common. So we're treating the generation in the GNP, the EES noted, inconsistently with the transmission itself. The thrust of their point seems to be that they should be treated consistently, and I'll leave that for them when they come to explain it in more detail. But I think from our perspective being here in 2001 there is a material resolution to the grid, grid transmission itself and we did raise questions as to the consistency and the wisdom of the dealing with the generation differently, which

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in our evidence and I'll ask Mr. Bowman to now address. But the context as we see it is that there was a debate, there was a study and there was a conclusion on the grid and it's soundly based, in our opinion.

Now, let's look at the generation aspects which seem to be a new issue as well as some other issues that relate to some other allocation matters.

(10:01 a.m.)

MR. BOWMAN:

A. In terms of the specific cost allocation issues that are raised within Section 6, within this section we're talking about cost allocation not specifically the requirement, so these are not changing the dollars to be recovered by Hydro, they're changing which customers would be paying those dollars. And in that--once we're into that realm the type of test that one normally uses to look at what is a fair and equitable assignment of the assets. And the costs among the various custom classes, the types of tests that normally talk about relate to ensuring that the rates paid by the various customer classes

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track the costs that they impose on the system and where those costs follow the benefits that arise from various assets.

In that regard there's three Cost of Service related items that we've highlighted here that I'll speak to. They all relate to assigning the costs related to supplying the capacity or the peaks on the system.

There is not a lot of debate in terms of assigning costs related supplying energy, that would be the sort of large hydraulic system, Bay d'Espoir, Holyrood or indeed on the backbone transmission. These are all related to smaller units that are simply there to cover the most extreme conditions of winter peak.

And the three that I'm going to highlight are the GNP generation, which Hydro now proposes to charge as being of common benefit to the Island Interconnected System, the Burin Peninsula transmission system which is now being proposed to be assigned as common. It has been assigned as common in the last hearing as well, but there was some discussion of how it would be treated in terms of

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consistency with the GNP transmission at that hearing. And I'll spend a bit of time on that. And the last is the concept of the generation credit to Newfoundland Power, which addresses their peaking units, their small turbine units to address the same sort of peak conditions.

In this proceeding most of this, the GNP and the Burin, two of the three items are generally dealt with in Exhibit GRH-3, which is filed in the third binder of the Application. And it sets out a new test that Hydro is proposing to use that updates the types of tests that were previously used and rejected by this Board in regards to the GNP transmission. The types of tests would go to--that are acceded in this Application go to do the various assets provide substantial benefit to the Island Interconnected System and if the assets pass that test of providing substantial benefit, therefore they should be assigned as common. We're not convinced that that test is determinative on terms of cost allocation. It's one thing to do a test a to whether it provides substantial benefit, but that seems

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MR. BOWMAN:

to ignore questions as to what are the relative allocations of the cost to ensure that it tracks those benefits and what are the relative impacts on each customer group in terms of the benefits that they receive. And on that latter point I would note when we're talking about costs of capacity. Page 31 we set out that the bench mark that Hydro uses and seems to be defensible in terms of capacity is that new, brand new peaking units that could be installed on the backbone 230 kV system have a--are quoted at about $100 per kilowatt per year as sort of a normal cost of that. Industrial Customers in the Cost of Service pay about 12.6 percent of the costs of peak related unit so that as a bench mark new capacity that is very clearly installed for peaking purposes which costs Industrial Customers about $12.64 for each installed kilowatt. There's not a lot of basis to be talking about other units that provide capacity that end up charging the Industrial Customers more than 12.64 for each kilowatt provided considering that they do get a higher

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quality unit in terms of that type of bench mark cost.

Going to the GNP specifically. There are three key facts in regard to the GNP Interconnection and the GNP generation that are key to assessing the degree to which these assets should be assigned as, as being of common benefit. And in reviewing this issue it's relevant to note that the customers that are served by the GNP transmission line are Rural Customers, so costs that are required to service Rural Customers, by legislation, are not to be included as part of the Industrial Customers' Cost of Service.

So with that as background, the interconnection of the Great Northern Peninsula had a couple of impacts on the system. The first is that it reduced the rates that Great Northern Peninsula customers paid because they were switched from being Island Isolated Rates to being Island Interconnected Rates, and in the final decision from the last hearing that was cited as being something like 2.75 million a year in benefits. Outside of that, though, the

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interconnection of the GNP, the evidence in this hearing at IC-399, and we review this at the top of page 33 of our evidence, indicates that overall the GNP Interconnection and the--page 33. The GNP interconnection, overall reduces the quality of service that is otherwise available to Island Interconnected Customers. There is less generation on the GNP than required to service those loads. In other words, in terms of someone sitting on the backbone 230 kV grid, from their perspective their service quality would be higher if that interconnection never occurred. If you snipped the line today, their LOLH would go down and there would be more availability of power on the system, the reliability would be higher. So, simply from that perspective it is--the project is simply not one that's undertaken from the perspective of benefitting the grid.

But in the end, as a result of that interconnection, Hydro's new proposal is that the customers on the Interconnected System will pay a share of the cost of the generation that's out on the GNP in the St. Anthony and

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area as well as at Hawk's Bay. And the evidence in GRH-3 indicates this was about $200,000 to do the Island Industrial Customers, $191,000 and it's a substantial cost to Newfoundland Power as well in the first step of the Cost of Service before we get into allocating the rural deficit.

Q. The $191,000 you mentioned, is that an annual figure?

MR. BOWMAN:

A. That's an annual figure, yes. That's in GRH-3, Appendix B. So, what we're got is an interconnection, an asset for this line running out to service the customers on the Great Northern Peninsula. That's a long radial line. The evidence is in those cases Hydro would normally take the diesels out of service once it connected the line, but in this case it kept it in, in order to keep the power quality out in that area higher. The diesel units that are out there have run primarily to support the customers in that area. Something like 99 percent of the times it's dispatched, is to support the people in the local area. And in the end, the customers

MR. BOWMAN:

sitting on the Island Interconnected System would rather it was not interconnected, quite frankly, from the perspective of their power quality. So putting those pieces together it doesn't leave one to immediately say, and as a result Industrial Customers should also pay $200,000 because there's some generation out there that benefits the grid. That's the core of the concerns that we have with the Great Northern Peninsula, that based on that set of facts it certainly seems apparent that these are properly costs to serve Rural Customers, they're not costs that are properly charged to the Industrial Customers when in the end they're seeing no benefit, they're actually seeing a detriment from the project of Rural.

The second--sorry. I would also note just in terms of the end mathematics of the proposed common allocation, because the Industrial Customers and Newfoundland Power make up effectively 94 percent of the allocation of demand related costs, in the end the diesel units that have been retained out on the GNP under a common allocation would be

paid 94 percent by Industrial Customers and Newfoundland Power and six percent by the Rural Customers, despite the fact that the evidence is that in most cases they're used and were retained for the benefit of those customers out on the Great Northern Peninsula. So it's an example of an asset that simply is not passing the cost tracking benefits type of test.

The Burin Peninsula is somewhat different. In this case we're not talking about generation, we're talking about a transmission system. In the case of Burin it's a fairly large load at the end of a-- effectively at the end of a long peninsula that Hydro has two transmission lines running to the southern terminus to service the customers in that area as well as Newfoundland Power has a gas turbine unit. Hydro has a small hydraulic plant, Paradise River, 8 megawatts, a part of the way down one of those lines.

In terms of the allocation of transmission lines, the review of this process of allocating transmission lines to common or

to being specifically assigned to one customer, as Mr. Osler noted, was some time was spent on this in 2001 and it's actually also reviewed in the GRH-3, the Exhibit GRH-3. And in the end the conclusion with regards to the GNP, and Mr. Osler noted, was to the extent that there is generation out on a radial system, if that generation can't even carry the local loads at times of peak, never mind make it back onto the core 230 kV grid, there's not a lot of basis to be saying that transmission line is providing beneficial support or increased power quality to the people on the 230 kV grid at the times when it really matters.

In terms of the Burin Peninsula, Hydro sets out two tests as to why these assets should be assigned common. One is because it services both Newfoundland Power and Rural Customers. We don't dispute that. However, it's something like 99.5 percent of the load is Newfoundland Power and half a percent is Hydro Rural, so it doesn't seem to be determinative on that point, even if one views it as providing services to both NP and Rural,

it doesn't give any basis to talk about assigning it to Industrial Customers. There are other allocations in Hydro's system that allow costs of an asset to be assigned to two customer groups, but not a third.

The other point that they make is that it connects significant generation. In viewing that system what we've seen is that there's an older transmission line, transmission line 212 that, TL-212 that connects the Paradise River 8 megawatt plant and it also allows for connection of the customers down the southern end, the Burin Peninsula, and in fact, Newfoundland Power's turbine is at that southern end which leads to a total of somewhere in the order of 33, 35 megawatts of generation.

Our issue is not with TL-212, it's with the second transmission line, TL-219 which says that even if one determines that Paradise River needs to be interconnected because of obvious benefit to the grid and perhaps even Newfoundland Power's peaking unit provides benefit to the grid, which we don't agree with because it's smaller than the peak loads out

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MR. BOWMAN:

on the Burin, there's no basis to be talking about a second transmission line, quite an expensive transmission line at that, just for that purpose. The only basis for the second transmission line is because there's lots of Newfoundland Power customers out there, quite a large load. And in that regard that doesn't lead to one saying that that second line is providing any benefits whatsoever to Industrial Customers.

Even on this point Hydro reviewed the Burin in 2001 and at the time they were proposing Great Northern Peninsula be common, Great Northern Peninsula be common and that Burin Peninsula transmission be common. There was a question that was put to them in the 2001 proceeding as to--which said suppose Great Northern Peninsula transmission was not to be treated as common, but was recognized as being providing service only to Hydro Rural, would there be other assets that needed to change classification. And Hydro said, yes, Burin would need to be assigned directly to Newfoundland Power. As I have it noted here,

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that was in the 2001 proceeding. So we haven't noted that in the evidence here. On the NP generation credit, what this refers to is Newfoundland Power purchases most of its requirements off of Hydro, but it supplies a small amount of its own requirements with its own hydraulic generation. It also maintains for the same type of local benefits that Hydro maintains the GNP generation, it maintains its own thermal plant which is a couple of gas turbines, one is 25 megawatts, one is 15, as well as a number of diesel engines. Similar to the GNP, these are located at various radial points around the Island and the locations of them is set out in our evidence at page 35 in a footnote there. And these units end up, these thermal units, specifically end up resulting in NP incurring a cost of about 1.691 million. I'm now at the middle of our page 37.

(10:16 a.m.)

So, at Line 18 there, it's noted that NP's General Rate Application will include the cost of these thermal units to be recovered from their customers at an annual cost of

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1.691 million.

In the end, the approach that Hydro proposes for dealing with NP's generation credit results in NP receiving back from Industrial Customers and Rural customers somewhere in the order of $995,000 as a result of keeping those units in service, or about 60 percent of the annual cost of those units.

I'm not going to spend a lot of time on the technical points about how one deals with the generation right now, but looking specifically at the end mathematical result, when Hydro has peaking units installed on its own system that are clearly a benefit to all customers, such as the gas turbines, Industrial Customers and Rural pay a total of about 20 percent of the cost. When Newfoundland Power maintains these gas turbines, the net effect is that Industrial Customers and Rural end up paying 60 percent of the cost, even though they're not the ones that are primarily served by these units. Those units are primarily there for the service to the local loads. So the end mathematical result simply doesn't result in

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cost tracking benefits in any way.

On the specific merits of the technical arguments that one should net these amounts off of the peaks that NP otherwise sets on the system. There seem to be two arguments that float about in that regard. One is that as a result of having the thermal units, NP somehow can shave its peak. So you're not really supplying them with firm load. That argument doesn't seem to carry a lot of weight and this is discussed at the bottom of page 37 and to the top of page 38 of our evidence. That evidence doesn't seem to carry a lot of weight, given that this load is firm load. It's charged at firm rates. It's equally reliable and available as any of Hydro's supply to Newfoundland Power. It's very different than, for example, the Industrial Customer non-firm load, which is maybe available and maybe not. The price is not guaranteed. It's on-- you know, it can be a very high cost per unit at certain times. So we're not talking about a non-firm load here. A non-firm load would be netted off of the cost of service. They do that for the loads

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MR. BOWMAN:
up in Labrador provided to CFB. We do that for Industrial Customer non-firm, but this is not a non-firm load. So that argument for netting it off the peak doesn't seem to hold a lot of water.

The other argument that's put forward is that if you don't give Newfoundland Power the credit as if they ran the units, the other alternative is they just might run the unit so that they do lower their peak. Assessing that argument, again it does not seem to carry a lot of weight. This is, again, on page 38 of our evidence. The fact of the matter is that there's a power policy in this province that says units should be dispatched in a way that is most efficient and result in the lowest costs being allocated to customers and there doesn't seem to be a lot of basis in an argument that one customer could gain the system by increasing the overall costs, but decreasing the costs that are allocated to them. That doesn't seem like something that that legislation is designed to allow to occur. So the thought that we have to put in

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some cost of service methodological approach to prevent that seems unnecessary, given that the legislation already effectively prevents that.

Those are the three plant allocation issues that are highlighted going through Section 6 of our evidence. There's also a section at the end of Section 6, 6.6 here starting at page 39 which discusses the NP's load factor and load forecasts. We spent some time there setting out some concerns in regard to the NP peak demand that was used as a forecast for the 2001 hearing versus the 2002 test year. At the time it seemed high. There was some--or the load factor seemed high, meaning the peak load seemed low. There was some argument in this regard. As time has come to pass and the results have come out, it was in fact low and as a result, the costs that were paid by Industrial Customers were well above the actual cost that they imposed on the system. We're not pointing this out in regards to any sort of redress or suggestion that there should be some form or retroactive rate making.

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It's just filed in regards to saying that there is a need for some form of principle basis to address the number that comes in, in particular for Newfoundland Power's peak demand. And the reason I highlight that is in all of the load forecasts filed with Hydro, and the Industrial Customers submit their load forecast and Newfoundland Power submits its load forecast, the Industrial Customer load forecast for peak loads are something called power on order, which means that they're under a take-or-pay contract for the peak that they submit. So if an Industrial Customer submits a peak of saying they would hit 50 megawatts, they send that in to Hydro, they're going to pay for 50 megawatts whether they use it not, and 50 megawatts is all of the supply that they will be guaranteed. If they intend to go above 50 megawatts, there's no guarantee of that supply and it can be very expensive. So there's a lot of incentive to make sure that that forecast is done correctly, and there is negative repercussions if that forecast comes out wrong.

In regards to Newfoundland Power's peak,

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in the absence of some form of demand energy rate that likewise puts a ratchet or some form of power on order, take-or-pay type of provision, the only effect that that peak number has is in determining the total amount of dollars that will be allocated to Newfoundland Power. There's no after-the-fact reconciliation regards to that peak versus actuals, and so what we've said is that given that, the number that's put in is--the rates that are to be charged is very sensitive to the Newfoundland Power peak that is put in and as time goes forward, after that peak, rates have been approved, there's no cost tracking in regards to that peak, in the absence of demand energy rate and in the rate structures that are in place. In a situation where that exists, it means that one would want to be very careful in looking at the peak that's submitted and the extend to which its defensible. That's what that Section 6.6 is addressing.

Q. Okay. That's all the cost of service specific issues that we need to speak of now. There are a number of rate design issues dealt with

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HUTCHINGS, Q.C.:
in Section 7 of your evidence. Some of those are no longer relevant but you comment briefly on the issue of the two-part rate for Newfoundland Power and the issue of Interruptible B.

MR. OSLER:
A. Generally, as we note at the beginning of this part of the evidence at page 42, we're now shifting from the overall revenue requirement where all the customers are interested in trying to keep it as low as possible. We've just dealt with the cost allocation issues that are done for the purpose of testing, whether rates seem to fairly allocate costs in the first instance. It's a benchmark really, the cost of service for that, and we were effectively asking questions about the adequacy of the benchmark.

When we get to rate design, we're looking at actual cost tracking through rates. We're looking a efficiency objectives, in terms of price signals to customers so they will behave with incentives to behave efficiently, and we're dealing with the issue of what happens

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if the forecasts are different than what happened in reality. Does the rate allow the cost tracking to still occur, or do we get into problems? Against that backdrop, the issue of the two-part rate for Newfoundland Power has been before this Board many, many times and it is one of the classic issues of discussion under rate design in Newfoundland. There are other issues that are raised in our evidence, but I think have been settled by Consent No. 2, with respect to firm rates to the Industrials.

The Newfoundland Power energy-only rate, as it currently exists, clearly doesn't purport to track demand or capacity costs and doesn't purport to track the difference that may occur if Newfoundland Power's actual capacity load differs from the forecast that Mr. Bowman was just talking about. This particular application sets out assessments of options and our evidence simply reviewed this material in the context of the discussions and the issues and made some comments with respect to the desirability of the price signal and sort of the links to DSM and efficiency. The

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longer term perspective that we're trying to give people incentive in Newfoundland and in the system, there's a lot of electric heating in the Newfoundland Power system, to think about capacity effects and to give price signals for down the road, so that the system evolves in an efficient way.

The evidence comments on some very specific mechanics around Option B in the Hydro filing, as to different ways to do a Newfoundland Power two-part rate. Whether we deal with weather normalization issues with respect to the hydraulic component going into the rate, obviously if you're looking at the peak that Newfoundland Power imposes on Hydro, you're looking at the effect that is net of what their actual peak on their system is net of their own generation. So how do you effectively plan with that in mind. The suggestions are that you look at some weather normalization in order to get around issues as they vary from year to year just to do with the weather, and secondly, that you look at issues of normalizing the hydraulic and standardizing the hydraulic component so that

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you're not worried about how they actually run their hydro plant, but you're using a stable standard that makes sense. And in our opinion, you don't get into their thermal dispatch at all, so you don't get into the issues of them having any incentive to gain the system, as Mr. Bowman was just talking about.

So, we deal with some of these technical matters, but from the point of the view of the Industrial Customers, any interest they may have in this issue is one of long-term evolution of the system, rather than short-term interest of the Industrial Customers. It makes no difference in the short run to the Industrial Customers as to how you charge Newfoundland Power. It may make a difference if it helps the system evolve more efficiently through time and thus we've provided some comment on that subject.

At the end of the evidence in this section, because most of the other material in this section has now been addressed through Consent No. 2, so it's not something that we are dealing with today. But at pages 69 and

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MR. OSLER:

79, in Section 7.3 of this section, the one other issue that is still alive, Interruptible B.

Interruptible B is a rate option that has been traditionally offered to the Industrial Customers and taken up by Abitibi Stephenville, I believe, and it effectively says this customer is prepared to accept a lower quality of power, a non-firm element to its capacity use and in return for that, it gets a lower rate for that power or gets a rebate, and effectively, the terms and conditions of this have been talked about by the Board and have been set out in the history and set out in a number of answers to Newfoundland Hydro questions 31 through 36 to the Industrial Customers. But it is a rate that's been around. It is a rate that has been used by the system to help meet capacity requirements in situations where there's a need to cut some load in order to supply--keep the system firm.

(10:30 a.m.)

It is a valid DSM measure. In fact, in

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response to Newfoundland Hydro 30, question 30 to the Industrial Customers, they asked did we file evidence that I'd given in some other hearings, and we did file the evidence that I provided in a 1998 hearing in Manitoba where we were dealing with curtailable rates as they call them there, which is the same as Interruptible B here, in principle. And we made the point in that evidence, page three if anybody's ever interested in looking at it again, that this is viewed in Manitoba as a DSM measure. It deals with load-related initiatives such as DSM. It's one of the bigger DSM programs in the Manitoba system. It differs fundamentally from initiatives that relate to incremental generation improvement. If you're going to cut somebody's load, you know for sure you've cut it. Either you've cut it or they've cut it, but it's cut. You don't have to worry about building a new generating unit and making sure it works. You have to have a reserve for it. You don't have to worry about the transmission losses. In fact, it provides all of these types of benefits with a high degree of certainty and

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if you back up it's benefit to the total system, you got to take account of the extra benefits you get from transmission losses saved and from reserve you don't have to hold.

So in the Manitoba system, we haven't been stressed to capacity, close to the peak of the load. We don't have to build new plant in our system for a long time. We don't have to build it, I think the latest information is until about 2020, the information that's been filed recently. It doesn't mean that we're yanking interruptible service or options to Industrial Customers. We're keeping them in that system because they have long-term benefits, and the long-term benefit approach is the one that Manitoba Hydro and the utility board there has focused on when looking at the retention of this option.

So in short, although there may be a surplus today compared to two years ago on this system, and it may be there for a few years, until 2010, '11 or '12, it seems remarkably shortsighted to yank Interruptible B and all the implications that come from it. And these are not things that can be stopped

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and started just like that. Our experience in dealing with Industrial Customers in Manitoba is it took a while to get it and it takes experience with the plant in order to maintain it, and if you don't keep it up, people lose that experience and lose that knowledge and lose that information. So it's in your interest to--if you think it's going to be of long-term interest, and the evidence would suggest that it should be when capacity issues return to the system, that you keep the customer--keep the program, keep the plan. So that's essentially what's being addressed at pages 69 and 70 and it's one of the elements of the application which is--and it's a rate issue, rate options issue which is still very much alive.

Q. Okay. Just to clarify the balance of the items. 7.1.2 of your evidence dealt with the rate form for Industrial Customers, and that, I understand, was dealt with in the mediation process and is no longer an issue at this stage?

MR. OSLER:

A. My understanding, it's addressed in the

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MR. OSLER:
Consent. That's right.
HUTCHINGS, Q.C.:
Q. Yes, and the rate stabilization issue, of course, from 7.2 have been dealt with in Consent 2 -
MR. OSLER:
A. Right.
Q. - which was filed this morning.
MR. OSLER:
A. That's my understanding. That would also apply to Attachment C, D, E and F of our evidence would effectively relate to some of the same things we're just talking about.
Q. I'd just ask you then, in conclusion, Mr. Osler, to summarize, and perhaps a convenience reference would be at page three of your evidence, the recommendations that you're now putting before the Board, and you can note those that are no longer of relevance in light of the earlier proceedings.
MR. OSLER:
A. Starting at line 17, the summary of our recommendations throughout are: number one, the material effect of increases in certain

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categories of revenue requirement since 2002, in particular operating and maintenance expenses, depreciation, return on debt which may have been addressed in the updating, and return on equity which is still a live issue, reflect the need for a more thorough assessment, in our view, of Hydro's operating costs and capital investment pace as they related to rates.

Secondly, there does not appear to be reasonable basis at this time for Hydro's rate payers to be faced with higher rates to reflect progression towards Hydro, treating Hydro as equivalent to an investor-owned utility.

Three, the assignment issues that Mr. Bowman referred to in the Burin Peninsula transmission assets and the GNP generation common assets seems to be a matter to be addressed in the manner that he discussed, and we think the allocations, as proposed by Hydro, are not consistent with the relative benefits that these assets provide to the various customer classes, and in particular penalize the Industrial Customer class.

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Four, the NP load forecast need to be reviewed further, and they have been updated since we wrote this, to assess the extent to which the NP's peak demands is currently forecast result in a reasonable allocation of demand costs and we talked there about the issue that Mr. Bowman just referred to, the big variation that we saw last time.

The next item, number five, I pointed out talking about longer term rate stability objectives and the extent to which they seemed to be causing a trouble. As I point out in my comments, that has been adjusted as reflect Consent No. 2 and Consent No. 3 to do with the effects of the RSP. So that we're not getting the fluctuations that we originally had seen and as noted in number five, we just have the ongoing issue of how to plan over time.

Number six, the NP two-part rate should reflect Option B of Exhibit RDG No. 2-2 or the revised definition of generation credit to normalize hydraulic generation. Items number seven, eight and nine are addressed, as I understand it, through the Consents and through the settlements.

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That leaves item number ten, Interruptible B, which I just spoke to and our recommendation is the program should be continued status quo and Hydro should be directed to study possible benefits arising from expansion of this program to other Industrial Customers.
Q. Thank you, Mr. Osler, Mr. Bowman. Those are my questions on direct, Mr. Chair.
CHAIRMAN:
Q. Thank you, Mr. Hutchings, Mr. Osler and Mr. Bowman. We will take our 15-minute break now so we will reconvene at five to, please. Thank you.
(BREAK AT 10:37 A.M.)
(RECONVENED AT 10:57 A.M.)
CHAIRMAN:
Q. Good morning, Mr. Young. When you're ready, please?
MR. YOUNG:
Q. Good morning, Chair. Thank you. I probably should introduce Mr. Robert Greneman, who is with me on my right. Mr. Greneman is our rates and cost of service expert. He's helping us with this Application.

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CHAIRMAN:
Q. Welcome, Mr. Greneman.
MR. YOUNG:
Q. Mr. O'Reilly hasn't returned yet, and I don't know if he's going to be due in a moment.
CHAIRMAN:
Q. Only goes to show you how much we depend on Mr. O'Reilly.
MR. YOUNG:
Q. Yes. The very first question I had is going to relate to a document. And if we start fumbling for paper, it's going to take at least ten minutes, for sure.
CHAIRMAN:
Q. See if we can track him down. Only goes to show you how important you are, Mr. O'Reilly, we're here looking at each other for one or two minutes. When you're ready, Mr. Young, please?
MR. YOUNG:
Q. Thank you. Good morning, Mr. Osler and Mr. Bowman. I don't have any specific questions for either of you individually. And I understand from this morning how you've broken out in, as Mr. Hutchings said, your division

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of labour. So any answer either of you wish to give is fine, fine by me. The first thing I'd like to bring to your attention is an RFI just to clarify a point this morning, because most of your testimony, both written and your summary this morning, is on Cost of Service and Rates matters, but if I could please bring your attention to NLH-46 IC, please? Some of your evidence this morning dealt with this kind of a Rate of Return on Equity issue. I just want to confirm that you don't hold yourself out as an expert in this are of Cost of Capital, is that correct?
MR. BOWMAN:
A. That's correct.
(11:00 a.m.)
Q. Thank you. Most of the areas I wanted to deal with this morning are the issues that you've identified as those which are still outstanding. And the first I'd like to deal with is one of the assignment of plant issues, it's the GNP generation issue you spoke about. I wonder, Mr. O'Reilly, if we could first seen J.R. Haynes, Schedule 2, please? Thank you. And just for clarification, when we were

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talking about the GNP generation, we can go about, I guess, it's about a third of the way down that page, just above the line which says, "total thermal", and you see the entry for Hawke's Bay, St. Anthony and Roddickton diesel is 14.7 megawatt. And that's what we refer to is the GNP generation, correct?
MR. BOWMAN:
A. That's correct.
Q. And I wonder, Mr. O'Reilly, if you could bring us to the next schedule, Schedule 3 of Mr. Haynes' evidence? This is a map showing, well, primarily--we'll stick with the island, because that's the part of the province that we're interested in. And you'll see that there are a number of generating stations and they're situated all around the island. Now, I suppose you would agree with me, it not being something of controversy, that the hydroelectric stations essentially are where they are because of geographic necessity of having to drop water from a large height. But, and we won't go into those. But the thermal plants are situated, and you can see the one there on the west coast of

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Stephenville which is a gas turbine; of course, in the far eastern coast where we are here; and there's one at Hardwoods; and the large thermal station at Holyrood, correct?
MR. BOWMAN:
A. Those are the large thermal stations as I understand it.
Q. Yes. And also I think you're probably aware, as you mentioned this morning, down in the very bottom of the Burin Peninsula there's gas turbines owned by Newfoundland Power?
MR. BOWMAN:
A. That's correct.
Q. They're not shown, but they're there. And you may also be aware that there has been a generation relocated to Wesleyville, which is in the northeast coast there that's also not shown. And of course, we have the GNP generation up at the far northern end there?
MR. BOWMAN:
A. Yes, that's correct. I have Wesleyville indicates a 15 megawatt gas turbine. There's also apparently a--I do have Port aux Basques thermal generation of Newfoundland Power's.
Q. Right. And just for--perhaps the

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MR. YOUNG:
Newfoundlanders here would know this without thinking about it too much. But Wesleyville is situated pretty close toward the Atlantic Ocean there, but of course, I was thinking on the Northeast coast, and Doyle's, the other part is in that very south, southwest coast extreme?
MR. OSLER:
A. Yes. It took me awhile to look those up. Yes, that's my understanding.
Q. There you go. To your knowledge, are there any advantages to customers that are served from the electrical system in having these generating stations sprinkled or spread out around, geographically around the province?
MR. BOWMAN:
A. Well, you would normally think about planning a system in terms of making sure that there's sufficient capacity to meet the system as sort of a first test. A second test would be if one then decided there wasn't sufficient capacity. And if you were adding capacity, a second test would be for hydraulic, where does it end up needing to be and for thermal is

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where might it make sense. And in this case it may have made sense to have it situated so that they both serve a purpose as supplying the firm capacity to the grid as well as being available should there be a transmission outage for local supply. So that can lead to the thought that thermal plants should be more distributed.
Q. Okay. But distributing the thermal plants around, I suppose, load or at the end of radial lines, would those be the sorts of things you were referring to a moment ago?
MR. BOWMAN:
A. That would be probably one consideration that went into a decision if you're adding plant, you know, where it would be located.
Q. Exactly. The paper mills on the west coast of Stephenville and Corner Brook, they probably benefit in that manner to some degree, at least, from the location of the Stephenville gas turbine. Would you agree that may be the case, that having a gas turbine at that load centre may be of some value to those customers?
MR. BOWMAN:

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A. I think we would say that the Stephenville gas turbine in the first instance is there to provide support to the entire 230 kV backbone grid, so that's its primary role. Presumably as a secondary role its also being located out in Stephenville can also address transmission outages or problems that don't relate to the supply of generating plant but the availability to transmit the power. So as a secondary function presumably the Stephenville turbine plays a larger role on the western side of the province.
Q. Okay. We were referring to two different functions and the 230 kV grid. And I assume that what you said about the Stephenville gas turbine would also apply to the Hardwoods' gas turbine and the largest thermal plant at Holyrood, they would provide not only the capacity to the grid but also there's benefits in having them where they are, is that correct?
MR. BOWMAN:
A. It would definitely apply to the Hardwoods. And when--the turbine related to Holyrood, the oil plays somewhat a different role.

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Q. The 14.7 megawatts of generation which is on the GNP, I think you would agree with me that provides a useful role, one of the useful roles it provides is supporting the reliability of service to customers in that area. Would you agree?
MR. BOWMAN:
A. Yes, I would agree. The reason I say that is I understand from the evidence filed that it primarily was retained at the time of the interconnection for that specific purpose and that in most times that it's actually dispatched, that's exactly the role that it's playing.
Q. This is sort of a hypothetical question, but if Hydro or Newfoundland Power were to determine that there was a need for additional peaking capacity, do you have any insight as to where they might choose to locate it based upon your knowledge of the system or do you have any opinion on that at all?
MR. BOWMAN:
A. Well, no. I think it would not be a straightforward exercise to where it would be located. There'd need to be a lot of

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MR. BOWMAN:
considerations that go into it, one being the type of system, things that we're talking about, but I'm not--I can't say at this point, you know, that it should be here versus there.
MR. YOUNG:
Q. Sure. What sort of factors would take into--I think you briefly touched upon. I wonder if you could elaborate on it a little bit more, sort of factors that might come into account as to the siting of such a plant?
MR. BOWMAN:
A. Well, when you're talking about a peaking plant that is not hydraulic, it's not dependent on the location of the rivers. Presumably one would want to be looking at the system type of factors we're talking about as well as where may staff be located in order to provide the support to it without needing to develop a new complement of people and, you know, how may that change sort of fuel resupply requirements or the cost of bringing in fuel for it. I suspect that there may be other environmental considerations. There's a long list of things that one would want to go

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through.
Q. From the perspective of adding capacity to the system, does it matter very much where it's located, aside from the other factors you just mentioned, but just from the point of view of the raw megawatts, if I can put it that way, does it matter where it's located?
MR. BOWMAN:
A. To the extent that one is adding capacity being driven by, say, a capacity shortage on the system, it doesn't matter to any great extent where it's located, except that the reliability of that capacity would be greater to the extent that it's on sort of the backbone transmission grid and not reliant on sort of long radial transmission lines to get that power to the grid so that you don't have an extra factor that you need to assume is going to be up and running at the time of your system constraint.
Q. When you say "up and running", you mean the reliability of the transmission line itself that might bring that generation to the grid, is that the point you're raising?
MR. BOWMAN:

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A. Well, the reliability of the transmission line itself or the losses that might be incurred, you know, on that. Like, I think if we look at the large peaking capacity that's installed on the island, all of it is on the backbone transmission grid, the gas turbines we talked about, Stephenville or Hardwood. Because that's sort of straight into the network of the system the losses would be lower, you're more likely to have that part of your system up and running.
Q. I suppose aside from that, just say another hypothetical, if we're here in the east end of St. John's and if Newfoundland Power or Hydro decided to put a gas turbine in this neighbourhood, it's not what you would normally think of as being on the backbone of the grid because it's in such a far extreme, there's a fair bit of load in this area. Would you agree that would provide a purpose, even though the generation probably wouldn't get out past Hardwoods or Oxen Pond because of the load that would just absorb the capacity? Would you agree with that?
MR. BOWMAN:

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A. Well, if you're talking about adding capacity to address a capacity shortfall, it's not of huge relevance as to where it's located on the grid in terms of the types of calculations that go into the loss of load hours. That would be set out starting from the table in Mr. Haynes' evidence that you took me to and through from that into the calculation towards the 2.8 hour per your target.
Q. If I could just refer you back to Schedule 2 of Mr. Haynes' evidence for a moment, please? And maybe Mr. O'Reilly could get the whole graph on there, the whole chart on the page, that would be useful. That's fine there, thanks. Looking at the net capacity column and at the very bottom it says "Total Island Interconnected Grid" and the number there is 19, 19.1 megawatts, correct?
MR. BOWMAN:
A. Yes, I see that.
Q. And I think you will agree with me that at least a portion of that is there because the Hawke's Bay and the Roddickton diesel is there at 14.7?

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MR. BOWMAN:
A. Yes, that's correct.
MR. YOUNG:
Q. Megawatts, correct? I wonder if I can now refer you to table 8 of page 37 of Mr. Haynes' evidence? And going down the middle column there called "net capacity", you'll see that the 19 point--nineteen, nineteen megawatts is the same number represented there, correct?
MR. BOWMAN:
A. That's correct.
Q. And now, just without looking at this table for too long, I think you'll agree with me that the purpose of this table and the purpose for which these numbers are presented here includes determining when the next capacity additions might be needed. And there's the LOLH calculation shown there as being a factor that might be considered, correct?
MR. BOWMAN:
A. That's my understanding of the purpose of this table.
Q. Okay. Do you disagree with using the nineteen, nineteen in this table for this purpose, any problem with that number being

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chosen?
MR. BOWMAN:
A. No.
Q. And would you agree that it makes sense for planning engineers to include all the capacity that they can get to the grid when they're making this assessment of LOLH?
MR. BOWMAN:
A. Given the grid that is there today, if nineteen, nineteen is the number of megawatts that are available on the grid in order to be able to support the customers that are there today, so it seems to be the sensible number to use in this type of planning consideration.
Q. And I think you've already said that, I just want to confirm this, that given that the capacity is there from the GNP, the 14.7 megawatts and it is used in this calculation and it has a collateral benefit of providing additional reliability, people on that radial line, that doesn't in any way detract the reliability aspect, doesn't in any way detract from the benefit it provides to the total megawatts capacity in the system, does it?
MR. BOWMAN:

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A. You're saying that--perhaps you can repeat the question?
Q. Yeah. I'm just wondering, the fact that the GNP generation is at the end of a radial line doesn't in any way detract from its validity as being here in this table as part of the nineteen, nineteen?
MR. BOWMAN:
A. Well, this table reports a number of different columns. My understanding would be is peak reflects the sum of the loads that are there, net capacity reflects the generation that's there. And then those two numbers, the components of them are taken out and run through some sort of fairly fancy model to come up with the LOLH column. I'm not sure that it treats each megawatt of generating capacity on an equal basis in moving from nineteen, nineteen to 1.1 and I think it would probably be a painful exercise to follow that all the way through. So, there's more going on here than just what is reported in this table. I think nineteen, nineteen is the right number to use there if one is thinking about what capacity is available to supply the

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grid that currently exists today.
Q. Okay. And without getting to deep into that because it's very quickly going to get over my head, but I assume you're talking about there might be things like forces outages ratios and those sorts of issues and losses might factor into those calculations. Is that the sort of thing you're referring to?
MR. BOWMAN:
A. Well, I haven't seen the model, but normally in calculating what something like an LOLH is what you refer to as sort of a probabilistic method which means that it's the sum of a bunch of probabilities multiplied out in terms of what's going to be available when. Forced outage ratios is usually one of the inputs to that. But not having seen the model, I can't necessarily say.
Q. Okay. I wonder if I could move to another issue of plant assignment. This is another one that you raised today. It has to do with the Burin Peninsula transmission lines. Perhaps, Mr. O'Reilly, we could bring up JRH-3? There's a map on page 6 of that document. There we go. Bring this map up just so we can

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MR. YOUNG:
have a quick visual reference for some of the discussion this morning. You referred to TL-121 and TL-219. The print is small, but I think you'll probably agree with me that 212 is the one which is, lies on the eastern side and 219 is the one which is to the west of those two lines, correct?
MR. BOWMAN:
A. That's my understanding is that TL-212 is the one that is on the eastern side and that the Paradise River plant is connected to.
Q. Right. And that one, I think you referred to--thank you, Mr. O'Reilly. That's much better. And you referred also to 212 as being the one which is older in age than 219?
MR. BOWMAN:
A. Yes. I don't have the number in front of me, but there's an interrogatory filed that goes through the age and the year they were built. And more important than that is the sort of value of the plant in service, that TL-212 was built quite a long time ago which it's not a particularly expensive line where the TL- 219 is quite a pricier and new addition.

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Q. Right. I'm just wondering, before we get into the details of some of the issues here, the position you're taking in this Application in relation to these lines, is this a position which is different than the one you chose last time or has there been some difference in Hydro's approach or in Hydro's report to give rise to your position at this time? I can't recall Mr. Osler testifying quite in this manner last time.
MR. OSLER:
A. The last time the focus of our attention was on the Great Northern Peninsula. We didn't get into the issues relating to this line in any substantive way. My recollection, I haven't gone back over it, but I know very much that the focal point was on the GNP.
Q. Okay.
MR. BOWMAN:
A. I would just note on that that we did consider that there was a group of these radial transmission lines. Our focus on the GNP. The Industrial Customers however did file an interrogatory in that proceeding, and I reference it at page 3 which is Attachment H

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to our evidence in noting that the question asked if GNP was not assigned to common but was specifically assigned, what other assets also follow on the same logic. And that's where Hydro's response says the assets on the Burin currently assigned to common would--"The Burin Peninsula shall receive similar treatment to the GNP assets." That's the reference there at page H-3 of our evidence, lines 20 to 26.
Q. Right, okay. And I think you briefly mentioned that this morning, didn't you, also? I'm just wondering if before we get into some of the other questions here, if you can provide the Board with information as to where you understand the gas turbine to be located, the one Newfoundland Power owns, just to put this in some perspective? If I was to suggest to you, just for clarity here, that it's in the vicinity of the Salt Pond Terminal Station, would you--is that your understanding?
MR. BOWMAN:
A. I'm told it's called the NP Green Hill gas turbine and it's near the southern terminus. I

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see a location called Green Hill.
Q. Right. Southern terminus of 219?
MR. BOWMAN:
A. I don't think we've distinguished between the difference once one gets onto NP system, but in the end, it's not connected directly to one of Hydro's transmission lines as we understand it, it's connected to the--there's a separate NP grid that is not shown on this map but is on the map on the wall behind us.
Q. Right.
MR. BOWMAN:
A. That interlinks all of those communities, including a community called Green Hill.
Q. That's right. And so even though that gas turbine is not directly connected to TL-219 or 212, it is on Newfoundland Power's grid, perhaps it's on a sub-transmission level or something so that essentially that power could--if 219 was taken out of service for any reason, that generation could go to 212 and vice versa, is that correct, is that your understanding?
MR. BOWMAN:
A. The first part of what you said, that the

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MR. BOWMAN:
generation is on Newfoundland Power's grid down on that southern end is our understanding. I'm just being cautious about if TL-219 is out of service, if you could go to 212, there's probably some core system operation considerations with that. When we considered this issue, we looked at -
MR. YOUNG:
Q. I'm just wondering, are you speculating about that now or do you have some knowledge as to a particular concern?
MR. BOWMAN:
A. No. What I'm indicating is when we asked the question about what is the sort of peak loads down in that area, and this was in IC-339, it was indicated that the Burin Peninsula's peak is something like 58.7 megawatts and our understanding is most of that is down in the Newfoundland Power area which makes up 99 percent of the load on that system. So the turning on the 25 megawatts similar to the GNP test isn't--doesn't all of a sudden get you electrons flowing back to the grid, if I can put it that way, in the times that matter,

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like winter peaks. At that time it basically just displaces a portion of the NP load, very similar to the GNP issue. That's why I'm saying in terms of whether it could flow back to the grid, our understand is at the time it matter nothing flows back to the grid.
Q. So you're just referring to the peak occasion? Are you suggesting that's the only time gas turbines are ever used, is that -
MR. BOWMAN:
A. No. But in terms of all of that consideration we just did on the Haynes' table 8.
Q. Right.
MR. BOWMAN:
A. We were comparing peak times to availability of supply to supply the peak. The LOLH primarily arises as a result of the peaks in January and February, some information was reviewed, as I recall it, from 2001.
Q. Is it your understanding that these lines essentially form, when you add in the Newfoundland Power portion of the network there, it essentially forms a loop, you know, power travels up and down 219 and 212 and his hooked back to the Sunnyside terminal station,

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is that correct?
MR. BOWMAN:
A. There's some RFI's that indicate that, yes.
Q. Right, yes. I'm just wondering at first glance these lines appear to be redundant. Now, redundancy in the areas of, in the area of electrical planning, it's not a dirty word, it generally means that you have additional reliability. Is the position you're taking driven by the fact that these lines are--both serve in a sense the same purpose and one is redundant with the other or I wonder if you can just expand on that, if that's a factor in your analysis at all?
MR. BOWMAN:
A. What we're saying is that there are two lines running down to supply a fairly large load that also has some generating complement down there. The two lines, as I understand it, do provide redundancy, but redundancy in itself is not a test that is set out to justify the two lines. For example, Granite Canal, which is 40 megawatts, it's more generation than is on the entire southern--that's the Burin Peninsula is connected by one line. So the

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fact that there's eight megawatts at Paradise River and the 25 megawatt Newfoundland Power generation does not in itself trigger the need for a redundancy, obviously. That's where the redundancy question comes in.
Q. Do you have any experience in a situation like this or analogous to this from another jurisdiction where you have what's essentially a radial situation served by two parallel lines that you can share with us as to how those lines might have been treated?
MR. BOWMAN:
A. I'm not aware of any, no.
Q. So you're not aware of any jurisdiction where a situation like this would have differential treatment from one line to the other? Because I think that's one of the proposals you're making, is that correct, perhaps 212 could be considered common but not 219 also?
MR. BOWMAN:
A. What we're saying in regards to the Burin Peninsula is that transmission line doesn't appear to merit any different treatment than the GNP transmission line based on what we've reviewed and what Hydro said in 2001. Given

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MR. BOWMAN:
that, there's no basis to charge these lines to the Island Interconnected System. We're willing to say that there's not a lot of cost associated with TL-212 and if anything, it does interconnect to Paradise River. So we don't need to go whole out and say both lines are not properly charged to the Island Interconnected System, but for goodness sakes, it doesn't switch us all the way over to say both lines should be connected. It seems like a reasonable position to say 212 seems to accomplish, to the extent that anyone can identify Island Interconnected benefits related to this system, 212 more than serves the purpose. The big expensive line in 219 doesn't seem necessary, it doesn't seem to provide additional benefits to the Island Interconnected grid. And in that regard, that's sort of a normal type of Cost of Service test.

MR. YOUNG:
Q. Okay. But it's a judgment you're making coming sort of afresh at this and there's no regulatory precedent you could refer us to, is

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there?

MR. OSLER:
A. Let me just say that if pushed, one would be saying deal with the line 212 it connects Paradise to the system, but not the rest of it. There isn't much cost involved in the whole of 212 and to be pragmatic, we took the position Mr. Bowman laid out. But we're not trying to do some new fangled theory of parallel lines which I hadn't seen before, frankly, markably parallel, going down to serve a load and how one should deal with it. Essentially, they look to be radial, they look to be not serving the basic system. And we're just trying to be pragmatic with Paradise River.

Q. I'd like to change topics and talk, for a moment about a the Interruptible B circumstance. I wonder if I can refer you to page 69 of your testimony at lines 14 to 15, there's a sentence I'm just going to read out and ask you to discuss, in a moment. It says, "in order to enable their operations to utilize this low quality power, there can be substantial required investments in capital,

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development of operating procedures and staff training". Now, you touched upon that this morning. I'm just trying to get a sense of context. You're talking in generalities here, are you, or are you specifically referring to Stephenville or one of the other customers?

MR. OSLER:
A. We were talking in generalities. Our experience is that Industrial Customers involved, some or all of those investments when they take seriously using interruptible power.

Q. In relation to the contract that Hydro had with Abitibi Stephenville Mill, does this apply in the same way? I'm just wondering if you can indicate to the Board--there is an RFI on this--what sort of investments were borne by the Stephenville mill and what sort of actions were taken in order to make itself ready to be able to participate in the Interruptible B contract. The RFI is NLH 39, RIC.

MR. OSLER:
A. Yeah, I believe Stephenville has provided an answer in 39 and I--they can elaborate on it.

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I haven't gone into the detail as to how their particular situation has involved these investments myself. So, I can't give you anything more than what I see here in this RFI.

Q. Okay. I just wonder, I won't take long with this in that case, but just looking at the items here, none of them strike me, except for one on the second page, and perhaps one on the first page, but we'll deal with the one on the second page at Line 4, Computer Modelling,

MR. YOUNG:
sorry, no, Engineering Study for Additional Pulp Storage Capacity, that's the only one that strikes me as having any real element of capital expenditure, would you agree?

MR. OSLER:
A. Well, I let them talk to it, but in terms of hard costs that you would see in terms of studies or investments, that certainly leaps out. My experience has been that there's also, more difficult to quantify, but there's staff, there's management and there's experience. When you don't have the experience, it's hard to get everybody on side

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to do something that intrinsically is disruptive to the plant's operation, but that management looks at as a method to help keep costs under control and keep the plant in existence. Once you've got it on side and got years of experience, and people know what they're dealing with and they pass it on for whatever generation, so to speak, from one group of people to the next. If you lose that, again, what's the cost in terms of hard numbers that you and I might look at? It's hard to quantify, but it's very real.

Q. And I think you make a reference to that, Mr. O'Reilly, if I could, back on page 69 of Mr. Osler and Bowman's testimony, lines--it's about 17, subscription to Interruptible B can require changes to many facets of a large organization in order to optimally respond to the requirement for"--that's obviously what you're referring to there. I'm just wondering if you can provide me with some comments on the nature of the contract that Hydro had with Stephenville in the sense that the contract ran for 10 years, now I know that there was some upfront growing pains and some

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preparation and some staff training and things of that nature, of that sort. I'm sure there would have been of the sort that you just referred to, but the 10 year period, does that strike you as a reasonable period for a company to recover its investment that it makes in the training, in the softer and the harder costs of an capital that might be required? Does 10 years strike you as a reasonable period of time for that?

MR. OSLER:

A. Yes, my comments are not relating to recovery of the investment, at all. They're relating to the fact that that continuity is important. You don't stop and start this type of program. If the idea is that this is of no longer any relevance in the future in Newfoundland, then that would be surprising, I would think. And it shouldn't be just gauged by a short term surplus of the type that exists today compared to two years ago. So, that's the focal point of the comment about investment and getting everybody organized, not the question of fairness and equity as to recovery of an investment made for a specific 10 year

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contract.

(11:30 a.m.)

Q. Well, just on that point, do you happen to know how much lead time was required by Stephenville to prepare itself to enable to provide these interruptions according to this, what's essentially a tariff?

MR. OSLER:

A. No, I don't.

Q. Do you have any information you can provide to us from some other jurisdictions as to how long that normally would take? For example, if an Industrial Customer indicates the willingness to involve itself in Interruptible--something like we'll call here, Interruptible B program, how much lead time would normally be required before its first interruption is ready, to its processes?

MR. OSLER:

A. I can't give you anything that's useful on that. I just know that it took in Manitoba's case, well over a year discussion to bring in the program in general, that one of the plants that uses it has experienced elsewhere in the country and it was very important to them, 50

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percent or so of their costs are electricity, so, it's fundamental to the management and their business plan. It isn't that degree of significance for an operation such as this. It's not the heart of the cost structure. And the issue of my experience in Manitoba jurisdiction is that, if you use the test you're using here in Manitoba Hydro and the Public Utilities Board, Manitoba would have terminated the program that they just finished reinforcing, you know, at the last hearing,

MR. OSLER:

last year, because the degree of surplus that exists in that jurisdiction is considerably greater and longer than the one you're talking about in this jurisdiction.

MR. YOUNG:

Q. Just back for a moment, before we get into Manitoba, I do have a few questions on that, but I'm wondering if we can make any comparisons with the lead time that's required to obtain an arrangement like Interruptible B on both the Utility's part and the customers part, how would that compare to, just say for example, we have 46 megawatts here, that's

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pretty similar to a standard, what I'll call off the shelf, gas turbine at that sort of name plate capacity, around 50, can you given me any indication as to how the lead time preparation would compare? And let me put it this way to you, more specifically, if a Utility identifies a need for some capacity, determines that it can be either obtained through interruptible program or a peaking generating plant, if in fact, the circumstances are such that it's indifferent, would you have any idea how the lead times would compare as to how quickly a company could normally get up a generating plant versus the interruptible program?

MR. OSLER:

A. I don't think I have anything useful. The generating plant, depending on which ones you're talking about, would be quite different, ranging from a hydro to a gas turbine.

A. Just for the purposes of discussion, the gas turbine might be the shorter, it might be the more useful analogy.

MR. OSLER:

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A. I mean, you would think that, if everyone was prepared and ready and willing, that it would be easier to do an interruptible contract than it would be to construct license and get approvals for a new facility, but you don't do these things typically on a spur of the moment and you don't do them for a short time period, as you saw here. There was a 10 year term to the original arrangement. So, I guess the heart of what we're saying is you don't tend to treat this type of exercise as an on again/off again exercise. You tend to have continuity, if you're interested in it as part of your plant.

MR. BOWMAN:

A. In regards to your question, the Manitoba program that was put in place started, as I recall it, in 1993, early '90s, it started as an experimental program and it was in place for a number of years, certainly at least 'til 1998 and potentially 'til 2001 and my recollection is a little bit fuzzy on that, as an experimental program and during that period, there was some periods where the customers were unable to respond to a

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curtailment because they hadn't yet sort of gotten use to the ability to do that. As I understand it now, it's--I know that it's offered on a permanent basis now, it's a permanent part of the rate offering that doesn't expire. So, in terms of lead time, it's one thing to say, after someone inks a contract, how quickly are they ready to maybe do their first curtailment or receive the first call. It's another to say, how long is it before they've got their procedures in place and everything is down pat, so you know that you can rely on that call when you need to make it, which is the type of program this is designed for. And I know--I just can comment that in Manitoba's case, it wasn't turned from an experimental on a permanent program until at least five years, perhaps longer.

Q. Okay. I don't mean to belabour the point about the Manitoba experience, but you raise an interesting circumstance we might look to for a moment. How many customers in Manitoba took it up in the experimental stage before it was decided to be sort of, rolled out, if I

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can use that term. Any idea?

MR. OSLER:

A. I believe there was two, initially, two, yes.

Q. I see. And do you have any idea how many are using it now, are there much larger number?

MR. OSLER:

A. No, there's one using it now that I know of, but there's also some interruptibles to do with fuel heating.

MR. BOWMAN:

A. I believe the last I heard, there may be two

MR. BOWMAN:

in the program now, it's in that range, one to three.

MR. YOUNG:

Q. And I think your evidence is that this program is available those customers who have at least 5 megawatts of load, is that correct? Do you have any idea how much of the customers that you have referred to, what size loads they interrupt?

MR. BOWMAN:

A. It's only one of those customers that I have any specific knowledge of because they were a presenter in a recent hearing there and it's

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in the same order of magnitude that we're talking about, like it's not 5 megawatts and it's not 100 at this point. It's somewhere in the--46 is probably not that far off.

Q. I see. You mentioned a few moments ago and already this morning that Manitoba Hydro's generating system is not capacity constrained, it's several years out before they need new capacity, is that correct?

MR. OSLER:

A. It's several years out before they need new facilities for either capacity or energy.

Q. Okay. Manitoba Hydro is in the wonderful place in history and time where they can, and location, where they can export sales to other provinces and to the U.S., is the correct?

MR. OSLER:

A. That is correct.

Q. Is there any possibility or is there any connection at all between the availability of having a number of customers who can provide interruptible power and opportunities for export sales?

MR. BOWMAN:

A. One of the changes that was made in the early

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2000, as the program was last reviewed, was to change the reasons under which Hydro could call for an interruption and it removed the ability for them to call for an interruption to capitalize on export markets. It's only to ensure availability of firm supplies. So, that answer is different, depending if you're talking about the first program versus -

Q. The first experimental program or the latter.

MR. BOWMAN:

A. - the current. As the program is evolved, they remove that ability to interrupt, just to capitalize on the export markets for that type of -

MR. OSLER:

A. I would just say, from another angle, that the value of the export market, in this sense, to Manitoba Hydro has changed dramatically int he last five years, in the sense of a whole bunch of things. So, thus the attention paid to it today compared to when it was first talked about as a program in the early '90s.

Q. Generally speaking, I'm wondering--not just talking about interruptible programs, but about capacity. I take it you'll agree with

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me that generally speaking, if you're going to acquire or build capacity or do other things to get capacity like an interruptible program, that you normally wouldn't make those expenditures unless it was needed. And you wouldn't--the second part of the question--normally wouldn't make those expenditures, for example, build that plant prior to it being needed, is that correct?

MR. OSLER:

A. That is correct.

Q. If, in a few years, Hydro finds that its forecast changed somewhat and it needs a new a capacity regime and there are a couple of RFIs on this, we don't need to go there and look at those, but these questions have come up, do you see that Interruptible B or that sort of a program could play a role in Hydro's expansion plan?

MR. OSLER:

A. I believe Hydro has confirmed that Interruptible B would be among the items that we consider, to address future capacity shortages. So, I think that again, you've got to keep in mind that's one thing to put up all

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the money to build a facility, the other thing to spend so much a year in order to protect the option of this type of a program. Like, you don't spend--Abitibi, Stephenville doesn't get a big payment at the beginning of the term in order to have a 10 year program. It gets so much per year. It's a pay-as-you-go type of approach compared to building a new facility.

MR. BOWMAN:

A. I'd also note that in regards to system

MR. BOWMAN:

expansion planning, there are two--in simple terms, there are two ways that one can meet the loads that are in the load forecast. One is to build more plants or one is to somehow reduce those loads. That's the whole, sort of, side of the demand side management. The ability to, sort of, build plant to serve load reflects a certain type of timing where you spend the expenditures, so the plant is in service by the time that you need it. On the DSM side, it needs to be a much longer term focus because you can't have a lot of these things turn on and off very quickly. It's the

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same sort of thought process behind putting in a rate for Newfoundland Power that encourages them to control their peak. It's a longer term consideration so that these shifts in load that will change the timing of the next generating plant that may be required on this Island are built into the plan and the ability to respond to that is already built into the plan, not the decision is made at the time "oh my God, we're in a crisis and now we need to curb peak." DSM plans are generally viewed over a much longer term period and Interruptible B, that type of program, fits into the thought of demand side management in that regard.

MR. YOUNG:

Q. Now when you say that about DSM plans in general and taking a longer period of time, I assume that's because normally, you're looking for--I'm talking about them in very general terms now, particularly as they're rolled out to general service and domestic customers. It takes a time for behaviours to change and there's a certain amount of time for the take up of the market to respond to the price

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signals and make the changes they need and it takes sometimes years and perhaps decades to get that sort of a change. Is that what you're referring to?

MR. BOWMAN:

A. That's one aspect, yes. The other is that if someone is talking about DSM type programs that the uptake you might get is not always clear from the outset. So where you might make a decision today that you want to build a gas turbine that's 50 megawatts, you might-- you can make that decision and go out looking for a 50-megawatt gas turbine. If instead you say we want to curb our peak by 50 megawatts, and as a result we're going to put in a program to have people convert from electric heating, you're not sure what the uptake on that program is going to be. So you need some lead time in order to see just how that's evolving. It's not quite as responsive and not quite as cut and dried as the generating complement addition side.

Q. Yes, okay. I'm just curious as to how that fits with the circumstances we're dealing with today, the Interruptible B for Stephenville.

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When you look at the other customers in the class, the oil refinery and the other two paper mills, do you have any sense of what willingness or abilities they have at present or might have within a reasonable period of time and reasonable capital to participate in a significant way in a plan such as this? Have you polled them or discussed it with them?

MR. BOWMAN:

A. No, we haven't. That's the type of thing that one would want to look at as you're moving toward decisions on next plant is can we keep the 46 megawatts from Abitibi and can we maybe get some additional from other people, and as a result defer plant, while we're separately also looking at what can we do on the energy side. Part of our recommendation is to go out and consider what else could be done in terms of offering this to other customers and how much uptake there may be.

Q. I didn't get the impression when we last spoke to the oil refinery representatives that an Interruptible load was something they were terribly interested in. I'm just wondering if

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we can focus on the customers that you're here for that might be willing to participate in the size of load. I realize I'm asking you to speculate and I don't care to ask you to make judgments about their processes, which are clearly not within your knowledge, but I'm assuming you'd agree with me that we can take NARL out of the picture at the present time, as far as which of these customers might be willing to consider this?

MR. BOWMAN:

A. Well, I don't have sufficient specific knowledge about all of their operations to comment as to whether they'd be interested in participating or if they were able to participate, on what portion of their load. What we heard last time from NARL is that some portion of their load, perhaps it's all but I'm not certain, is very sensitive to power quality and they're not prepared to accept lower quality power on that portion of load because it's very expensive. It doesn't mean that another portion of load, they're not willing to accept a lower quality of power.

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What we're saying in regards to Abitibi is that on some portion of their load, they need a higher quality of power. On another portion of the load, they don't need that higher quality of power. They don't want to pay the extra for that higher quality of power, and they're willing to accept via an Interruptible B type contract or Interruptible B type rate a lower quality of power at a lower price that provides them with that benefit and provides the system with the long-term type of benefit that we've been talking about. So maybe there's a distinguishing part in terms of the portion of the load that we're talking about.

MR. YOUNG:

Q. Just perhaps if we can focus on Stephenville, just for a minute. Do you have any sense as to how the 46 megawatt number came about and how that fits in their process?

MR. BOWMAN:

A. I've read in the transcript in regards to how it fits in their process, regards to the different types of machines, but I have no knowledge as to how 46 was calculated versus some other number.

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Q. Okay. So you wouldn't be able to confirm or otherwise if the 46 relates to the pulping operation, if they have a storage, large storage tank there that they happen to have which can hold an awful lot of pulp and they can shut down that part of their process while other parts of the paper making process continue? You can't provide information of that sort, can you?

MR. BOWMAN:

A. Well, anything I would be give in that regard would be only as a result of reading the transcripts in this hearing, so it's already in the record.

Q. Okay. It's a good circular, isn't it, okay. So the comments--I just want to make sure we understand this, the comments you made about the longer-term benefits and the slow take-ups and those sorts of things, I put it to you, it doesn't really apply to Stephenville and I'm not sure how it would apply and perhaps you can help us on this, I'm not sure how it would apply to the other two paper mills either. It sounds to me like you're bringing a generality and bringing it to a very specific

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circumstance for your customers, and there's only four of them.

MR. BOWMAN:

A. Could you repeat the question?

Q. I'm just wondering, you made some comments about ten minutes ago about the importance of continuity and longer lead times that are required in order to see benefits from a DSN program, and I'm just wondering how those general comments--and I accept that they have general applicability, but I'm just wondering how they apply to the circumstances of the Industrial Customers here in the province, on the Island part of the province.

MR. BOWMAN:

A. Well, what we're saying in that regard is that when both customers--both the customers' side and Hydro's side, there is the benefits that come from continuity on this type of program and the type of certainty that arises thereunder, that if a comprehensive plan is put in place that says our system began to get short at, say, 2010, we can address the energy side by doing some things on wind, we can address the capacity side by relying on

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Abitibi, okay, well wait, we'll go talk to them in 2009, it would be a bad time to find out that this time they decided they're not able to do that because they haven't got that type of continuity or they're not sure they want to sign on for an on and off type of program under that type of condition.

MR. OSLER:

A. You know, I think--we haven't addressed the extent to which there'd be uptake from others, beyond Abitibi. We have noted the Abitibi one

MR. OSLER:

and there are certain physical features of that facility which you've osberved (phonetic). The Abitibi operation is facing significant cost increases as a result of this Application. One of the things it is also facing is a loss of the whole Interruptible B process. The objective here is not to make sure there's no Abitibi load whatsoever by the time you come around to your next set of problems, it's to try and maintain a partnership with the people that are here in a long-term basis it's got some continuity, so DSM's objective is not to get rid of the

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Abitibi load in its entirety, it's to provide a solid basis for planning and try and help its ongoing existence, as well as curtailing its load to where it can afford to be curtailed. So, I think all of those things would be in the background of some of the things we're thinking about here. The overall increase in the rates and any amelioration for Abitibi is not just the rate increase, it's the loss of the arrangements with respect to the Interruptible B. It's a remarkable coincidence of timing. And the overall effect that you can well imagine.

MR. YOUNG:

Q. Okay, well that's sort of removed from the discussion we had a few minutes ago. I think I'd like to move on, if I might, to another issue that I know you've presented some testimony on and I presume you have some strong views on, and that's Newfoundland Power demand energy rate structure that's being proposed. I wonder if I could bring you to page 45 of your testimony please. Now you mention there, there's a heading there under "Price Signal" and the last sentence of that I

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think sums it up well, I'll just read it "To the extent that these Industrial rates are appropriate and track valid incremental costs on the system, a similar rate structure seems appropriate for Newfoundland Power." I wonder if you could elaborate on that? I think the reference there is to the fact that the Industrial Customers have a demand energy rate structure and that Newfoundland Power does not, is that correct? Actually, the point I'd like you to discuss, if you care to, is the tracking of valid incremental costs on the system and the dynamics that are followed by demand energy rate structure, as opposed to an energy only rate structure.

MR. BOWMAN:

A. Well I'd just start by noting that this section of the evidence we're discussing at page 45 is a summary of a number of benefits that were actually highlighted in Mr. Greneman's Exhibit No. 2.

Q. Right.

MR. BOWMAN:

A. And some comments that we have on that. In regards to price signal, what it's setting out

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there is similar to what we talked about earlier this morning. Absent a demand energy rate for Newfoundland Power, there is no cost tracking to changes in the peaks it imposes on the system, which is very different than the situation of Industrial Customers where there is some form of cost tracking. It's a striking difference. I'm not sure whether incremental costs is the underpinning for it, as much as just ensuring that rates track cost and relative loads imposed on the system as we go forward. Incremental cost in regards to the demand in regards to changes in peak demand is somewhat of a more difficult concept, but certainly in regards to tracking the costs of the higher peaks and the relative uses by various customers, a demand energy rate would allow for some form of reflection of the peaks that are imposed by Newfoundland Power in the rates that they pay.

Q. Mr. Brockman has, I'm not sure if you're fully up to speed on the point here and maybe it's unfair for me to ask a question about his evidence, but I'll give it a try anyway. Mr. Brockman has made a comment that there is an

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essential difference because Newfoundland Power is the only customer in its class, whereas there were four in the Industrial classes, does that change in any way or have any impact upon the point you just made? Does that matter?

MR. BOWMAN:

A. No, and I think that's underlined by both the type of wholesale rate designs that one would normally see in other places, as well as the thought that in cases like 2002, when

MR. BOWMAN:

Newfoundland Power's actual peak came up considerably higher than had been forecast in the Cost of Service, such that they grew from--the numbers are in here somewhere, but something like 78 percent of the system to 82 percent of the system, there was no cost related--no change in the amounts that they paid as a result of becoming--being a bigger part of the system in that year. The bill at the end of the year did not reflect whatsoever any change in the rates that they paid, despite the fact that they were a bigger portion of the load that had been assumed in

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the Cost of Service.
MR. YOUNG:
Q. The demand energy rate structure that applies to the Industrial Customers is derived from the embedded Cost of Service Study, correct? I'm just wondering if you could confirm that and I'm also just wondering if you had any comments as to whether or not there would be a problem that you are aware of, of applying the Cost of Service Study that we filed in determining demand energy rate structures from that for Newfoundland Power?
MR. BOWMAN:
A. The demand energy rate for the Industrial Customers is derived from the Cost of Service Study, as I understand it, and the rates that I've seen in the rate schedules mimic those that show up once one does the calculations in the Cost of Service Study. So I can confirm that part. The specifics of designing the Newfoundland Power rate go quite a ways down the road, it's sort of technical considerations on a number of factors. I would expect the Cost of Service Study and the relative amounts of demand versus energy costs

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on an embedded part to be a significant part of that, but I'm not sure it quite as cleanly lends itself to lifting two numbers from the Cost of Service Study and putting in the rate schedule as may be the case for Industrial Customers.
Q. Mr. Bowman and I know in particular you had a great involvement with the RSP and you may have a sense of this from your observations, Newfoundland Power's present situation is an energy only rate and it's coupled with a, prior to our application, I mean, the status quo, it's coupled with our RSP and their RSA, the Rate Stabilization Account, would you agree with me that those three elements working together provide a situation which constitutes a high degree of earning stability for Newfoundland Power, higher than you would normally see, perhaps for a distributing utility or is it typical?
MR. BOWMAN:
A. I want to be cautious here because in regards to the type of things we're talking about, the RSP impacts are considerably different under the consent exhibit that has just been filed,

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as opposed to what was there under the previous one, particularly with regards to the load variation component which is the one that we spent quite a bit of time on here, being concerned about the price signal. I haven't looked at burden instability for Newfoundland Power versus other distribution utilities being served by wholesalers, so I can't comment on that issue specifically, but it also may hinge on the RSP filed in the consent versus the previous RSP.
Q. Okay, we won't dig too deep into that one. I wonder if you could make an observation about demand energy rate structures, as opposed to energy only rate structures from the point of view of volatility. Would you agree that it is inherent in demand energy rate structures that there would be an additional or an increased amount of volatility as opposed to an energy only rate structure, or do you have any basis upon which you can make a comment of that sort?
MR. BOWMAN:
A. I think there's a number of considerations that go into answer that question. Demand

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rates are usually cited as being some component of ensuring more stability within the amounts that customers pay and that would be a very general comment, but it's very dependant on how that demand rate is structured. But my comment would more so go to things like rackets or take or pay provisions being very much about stabilizing the revenues to a utility, so in terms of moving from an energy only rate to a demand energy rate, I'm not spending as much time on
MR. BOWMAN:
that as saying the form of the demand rate lends itself to putting in measures that stabilizes the revenues to a wholesale utility.
MR. YOUNG:
Q. Okay, well I realize this is a, the core part of your evidence, but I just have one further question about this. Do you have anything in your knowledge or background that you can provide to the Board as to mechanisms or strategies that can be used for distributing utilities when they purchase power on a demand energy rate structure that might buffer what

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otherwise might be volatility as to their earnings or other untoward effects, I don't know if you can provide any information on that?

MR. BOWMAN:

A. I would think that would go to issues on Newfoundland Power General Rate Application.

MR. OSLER:

A. Just, I mean, generally speaking, the work that we've done, not to be so evasive here, but we've worked on industrial issues where the concerns you're talking about are not the focal point of our attention. While we've worked for major utilities such, as a wholesale nature, such as Yukon Energy where they are the wholesaler and not the distributer and the issue certainly arises in discussion with the distributor, not dissimilar to what we're talking about here. On the other hand, from the point of view of the wholesaler, these are costs that go with the provision of the generation of transmission and to the extent that somebody is planning a system around the load, the capacity part of it, then the risk should be

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borne by the customers that flow through to the distribution part, and you can get into debates about how to do it, but the focal point of our attention hasn't been ways to ameliorate concerns about instability from the distributor's point of view.

Q. If I might, just as a follow up to that point, so I understand it, are you saying that one of the--if I can put it this way, products that's being sold by the wholesale utility is in fact capacity and that there is a way of reflecting that in the demand energy rate structure?

MR. OSLER:

A. That's, I guess, going to the core of it, whether it's a price signal issue or cost tracking issue, whatever, that's the core of the perspective is the system--the wholesaler is providing, through generation and transmission, capacity, as well as energy. That's why they charge Industrial Customers who are larger customers of the system on that basis, and the question that always surfaces is why would you charge the wholesale guy differently? And from a fairness point of view, from efficiency pricing point of view,

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et cetera, and the argument that comes back occasionally is, well, if the wholesaler doesn't like it--the retailer doesn't like it, because it's going to be unstable to their bottom line and that will--they have to reflect that through their customers and depending on your perspective, people then say, well that would be a good idea to reflect it through their customers and their customers would know the capacity counts, as well as energy, so why don't we all think about that when we're dealing what a distributor's rate hearing.

Q. Okay, thank you. Those are all my questions, Mr. Bowman, Mr. Osler. I appreciate your testimony. Thank you.

CHAIRMAN:

Q. Thank you, Mr. Young. Good morning, Mr. Browne, when you're ready please.

BROWNE, Q.C.:

Q. Good morning gentlemen. That last theme that you were asked in reference to demand energy, I'd like to pursue that a little. What do you understand is Hydro's proposal for a demand in energy in the demand energy rate in this

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proceeding from the way you've read the Application? Mr. Bowman or Mr. Osler -

MR. BOWMAN:

A. I'm not necessarily completely clear. My understanding is it's--there is a study that's in the record in regards to implementing a demand energy rate that seems to be, I believe the word was "endorsed" by Hydro and proposed but there's a rate schedule that's filed that indicates an energy only rate to Newfoundland Power, so it's one of a number of issues that

MR. BOWMAN:

we were not entirely clear on what was being applied for, similar to the Acres Hydraulic work or the GNP generation, there seems to be one proposal from Hydro, but the rates that they propose to charge don't seem to reflect it, so I don't entirely know what's on the record being proposed by Hydro.

(12:00 p.m.)

BROWNE, Q.C.:

Q. In terms of your own knowledge of the demand and energy charges, we notice there was a mediation effort and there were points that the parties agreed upon in the mediation, as

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found in Consent 1, but when we go to part 2 on page 5 of the Mediation Report and Mr. O'Reilly, I don't know if you can put that up there, the issues on which parties disagree we saw k) should Hydro's wholesale rates to Newfoundland Power include both demand and energy charges or should they remain an energy only rate. Now, you were involved in the mediation effort, were you not, Mr. Bowman?

MR. BOWMAN:

A. Yes.

Q. And there could be no--there was no agreement in reference to this particular issue, but what was your position, can you tell us that?

MR. BOWMAN:

A. The only positions that we have filed are with regards to the evidence that we have here that there is, our demand energy rate to Newfoundland Power would seem to have some benefits associated with it.

Q. In reference to that issue, yesterday the Industrial Customers requested an update on the load forecast and we see that in Information No. 17. Can we go to that for a moment, please?

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MR. BOWMAN:

A. Yes, I have that.

Q. Do you want a copy of it or can you pick it out--you have it from there? Can I just want you, if you can explain some of this to us probably in layman's terms from your own expertise, where you see the load factor there and it varies, 49, but averaged over a ten-year period to 48.96. What does that in fact mean?

MR. BOWMAN:

A. Well the numbers that are shown there and I see there's notes that indicate that the numbers that are shown there are from the type of information that would filed by Mr. Haynes in this Application, indicating the Newfoundland Power loads that Hydro supplies. There's a number of different Newfoundland Power loads that are talked about, there's a native peak, there's a Hydro supplied peak, there's a peak less generation credit, so we're talking here in terms of the actual peaks that they impose on Hydro's system and Hydro's supplies. And if one looks at the total energy that Hydro provides to

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Newfoundland Power across row A and the peaks associated with supplying that energy across row B, you come up with certain load factors where they vary over time, depending on the specific numbers that show up above, but there is certain averages for that developed under columns 11 and 12. So those are the longer term more sort of stable, in terms of the load factors that Newfoundland Power would impose on Hydro's system.

Q. We see the load factor here below fifty percent, does that suggest efficiency in the system?

MR. BOWMAN:

A. Load factor of 50 percent means that compared to the peaks that are imposed on the system, they average demand on the system is about half that high. It would mean that the winter peaks are considerably higher than the amount of usage in summer. I'm cautious about the word "efficiency" because different types of customers will impose very different load factors on the system. For example, Industrial Customers may be very high load factor customers where some may operate at 95

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percent load factor and you might think of an 80 percent as a relatively inefficient type of Industrial load. But for the wholesaler, it is--the lower the load factor, the less efficient the load is in terms of comparing the peak to the annual energy. So this is less efficient than 60, but more efficient than 40, I guess, it's hard to make a more valued judgment.

Q. Ideally what should the efficiency be or what should the load factor be?

MR. BOWMAN:

A. It depends on the type of system you're talking about in the--a load shape, I guess is the right word, on thermal based systems where you build for capacity and once, for example, like a diesel system, in a classic year, you build for capacity, you have to meet the winter peak. Once you've built enough capacity to meet the winter peak, you could theoretically meet that peak all year round. The more the energy grows, it doesn't derive investment and plant because you've already built, the flow of that energy is not driving high winter peaks, so the higher the load

factor on a thermal system, the more efficient is the use of the plant that you have installed. Hydro systems are a little bit different because once you've built to meet the peak, you may still have energy constraints because, say a 40 megawatt plant, like Granite Canal, can't run at 40 megawatts all year round, you'd run out of water. So there's some different considerations that go into a hydro-based system, like you would still normally talk about increasing the load factor as being an improvement in efficiency of the system.

BROWNE, Q.C.:

Q. Would it suggest that the system where you get below fifty percent, that the system itself, the capacity is two times overbuilt than what's necessary?

MR. BOWMAN:

A. No, it would just suggest that if the peak there, looking at column 12, is 993 megawatts, it is--it's considerably higher. The usage at that time of year is considerably higher than the average usage throughout the year, so it's not like you can get by with half the plant if

you had a perfect load factor because, like I say, on a hydro system, it's considerably different, a different animal in terms of the energy consideration. On a diesel system, if you had a peak or I'm sorry, an energy of 4263 at a hundred percent load factor, you could get by with a lot less plant. On a Hydro system, that's not necessarily the case, but as I say, I go back to my comment that generally improving a load factor is considered a better use of the assets that are in service.

Q. And does it suggest that the assets or the capacity is not properly being utilized when we see a load factor of less than fifty percent?

MR. OSLER:

A. I mean, I think you're going to have trouble getting anyone to make a generalized statement, or at least to get anybody who's dealing with it technically to make a generalized statement that 50 percent is some magic number. I know that in the Manitoba system, we're talking about domestic loads at 60 percent roundabout. It depends a lot on

your mix of loads, your industrial composition, you degree of electric heat, which will tend to be "inefficient" using the standards we're talking about, whether electric heat is growing or shrinking, whether you're encouraging it or discouraging it, all those things. Usually what somebody does is get into the details of a DSM study or demand side management type of study to understand where there are efficiencies that are just not being captured and how you could improve the picture and how much improvement could this system do at this time, and that usually requires some detailed studies and people can argue over the results, but until you have such a piece of information in front of you, I wouldn't want to generalize as to what one particular number means versus another number.

Q. You mentioned a few times in your evidence there about electric heat and the expansion of electric heat. You're talking about space heating. Is that what you're referring to?

MR. OSLER:

A. Yes.

Q. And can you expand upon what you mean by that?

MR. OSLER:

A. Use of electricity to provide space heat in a home, for example, is what I'm thinking of, and it is generally perceived that if you take oil or diesel and you transform it into electricity and then use it to heat a home, it's not viewed as efficient from the point of view of energy use.

Q. Is that what we're doing here in this province?

MR. OSLER:

A. It would appear to be.

BROWNE, Q.C.:

Q. How do you come to that conclusion?

MR. OSLER:

A. I gathered from the evidence that Newfoundland Power has a significant element of electric heat with its residential and it hasn't been shrinking, but I haven't explored it in detail. I just picked that up in looking at it.

Q. So is the system being built to serve the end user to give electric heat, it's all been built around Newfoundland Power expanding into

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electric heat? Is that too much of a generalization or is that true?

MR. OSLER:

A. Well, it seems to be if you took Industrial Customer loads which haven't been growing and have a high load factor and you compared them with the residential loads with electric heat, I gather electric heat is a dynamic element and tends to be growing, from what I'm picking up, in which case the system's capacity will tend to be expanding and the expansion that's occurring is not certainly coming, say, from the Industrial sector adding more capacity requirement. It's coming from somebody else doing it, and if you were looking at other things being equal, electric heat would be something that would tend to expand capacity more than it would expand energy. And so yes, that could be a factor in the system's growth. It would also expand the costs because as you're running the oil facility to do that, you are contributing to the extra cost of the whole system, which all the customers will be tending to be addressing through, whether its RSDs or fuel adjustment rates or whatever, and

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you're having more of an adjustment to do because you have more of that type of use than what might otherwise be the case if somebody changed it.

I want to put the other angle. I'm talking efficiency from an energy point of view in running an electric system. Why does electric heat tend to expand, whether its in Whitehorse or in Newfoundland? Because from a customer's point of view or an apartment builder's point of view or somebody else, they may think it's more efficient from their point of view. It's a lot easier to deal with, a lot easier to put in, a lot easier to meter, et cetera. So efficiency has different perspectives coming from different peoples points of view.

MR. BOWMAN:

A. I'd want to underline the point that we're talking about electric heat a lot in regards to the peak. It's not only a concern in regards to the peak. There's a--to go to the Yukon example, there are systems up there that are diesel systems that are not capacity constrained. There's more than enough diesel

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plant there to supply the peak, but there's still a prohibition on electric heating in those communities because supplying that energy via burning it in a diesel engine and then supplying it down the wires to people's houses with all the associated losses is a very inefficient use of the power, and the prices don't necessarily reflect that. So they get around that by simply prohibiting it, but the concern is not because it's going to drive higher peaks. It's just because it's going to increase the energy side, increase the consumption of high-cost diesel.

MR. OSLER:

A. I'd say two things. They prohibit it in those diesel systems up north by prohibiting it or by setting a price that is prohibitive. Like if you expand more than such and such a level, you're going to pay for it, and you're going to pay for it based on the real cost of running a diesel engine. So that tends to stimulate attention.

Q. In terms of the system therefore being built around the expansion into electric heat, how does that affect the Industrial Customers and

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their own costs? Does that affect them at all?

MR. BOWMAN:

A. I'll talk about it on a very sort of simple incremental basis. Sort of the common refrain on hydro systems like this is that the average cost installed today is generally lower cost than the cheapest next plant addition. So to the extent that the system is having to grow and build new plant and make investments in Island Ponds or whatever other options are

MR. BOWMAN:

available, Holyrood, the next Holyrood unit, and that's being brought about as a result of electric heat growth, everybody's rates are going up. So I don't know whether the down side quite correlates in the short term, but over the long run, to the extent that the load on the system doesn't grow, the relative percentage of good low cost hydro that's been here a long time makes up a bigger portion of what's serving the loads today and the average price is lower. So I think not just Industrial Customers but all the existing customers are hit.

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MR. OSLER:

A. Could I just make one--two sets of comments. We don't want to be interpreted as saying we're against growth. The Voisey Bay processing facility can produce a lot of jobs, a lot of development and will also require new capacity. So I don't want--a long time ago I was in a hearing where the focal point in the late 70s in Ontario, electricity costing and pricing to try and get at large industrial users for expanding systems and increasing the costs for all the people of Ontario, and that didn't fly in the end after a year and a half of hearing. But what you're after is trying to make the system as efficient as possible so the cost can be as low as possible for all of the customers, Industrial as well as everybody else. I think that's the point. And there are tests to do with DSM which I think some people have put in evidence here. There is, among other things, tests that say make sure you spend money on demand side management and efficiency measures that at least bring benefits to all rate payers, and the type of things we're talking about fall into those

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types of thinking. It's not a blanket saying you shouldn't have growth in uses that make sense.

BROWNE, Q.C.:

Q. And by moving away from an energy-only rate for Newfoundland Power to a demand and energy rate, will that help with that efficiency, in your opinion?

MR. OSLER:

A. The general perspective of our evidence is that it provides a price signal and a price signal generally from an economics perspective is something that helps move towards efficiency.

Q. It's quarter after. What's the plan today, Mr. Chairman?

CHAIRMAN:

Q. We started a little bit late this morning. I'd be inclined, Mr. Browne, to go to 12:30 if that doesn't--and we'll take an hour for lunch, which might give us--gain 15 minutes or something like that, which might be advantageous at the end.

(12:15 p.m.)

BROWNE, Q.C.:

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Q. Just continuing with this theme, I was looking for an analogy in terms of the load factor. In the airline industry in the United States, before deregulation, the planes were all flying around with 40 and 30 and 50 percent capacity just being used, and of course, that couldn't continue. People were out buying planes and the system came, if I can use a poor choice of words, came crashing down around them, I guess, and deregulation resulted and we see now the airline industry, the capacity is greater. We see 80 and 85 percent in some instances.

In terms of electricity and capacity and load, is that same analogy true, that where we see low factors of 49 and 50 and 48 percent, should we not be seeing, through greater efficiency, more use of the system as it's currently entailed rather than expanding upon it or in the airline industry, buying more and more aircraft to fly 40 and 50 and 60 percent capacity? What's your comment on that? Have you heard that analogy before?

MR. BOWMAN:

A. I haven't heard the analogy and I'm not sure I

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can comment a lot on the difference between electricity and airlines. To the extent that it's relevant, I guess what I would say is if I look at column 12 on that exhibit, it indicates the math that goes into calculating a 48.96 percent long-term load factor. In the absence of the right decisions in terms of pricing signals or whatever else, it's hard to know how much, to be colloquial, how much low-hanging fruit there is in terms of improving that and I think improving that is likely a

MR. BOWMAN:

direction that's going to be beneficial to the system. I can't say that it would be better if instead that number was 80 percent. 51 or 52 or 53 is probably better than 48, but the system would have to look a lot different in order to supply that if it was 80 percent, if that were even possible, you know what I'm saying. The system has been designed in some ways to address the type of load factor that's there. We know that incremental improvements will probably change the incremental development plans of the system, but massive swings may be a different animal altogether.

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BROWNE, Q.C.:
Q. In terms of your own position, do you support a demand energy rate over the current energy-only rate?
MR. OSLER:
A. From what we've seen, the demand energy rate would seem to be a logical structure to move to in Newfoundland, compared to the energy-only rate, but it's not--it's something we've addressed more because it's of interest to everyone than because it's a big driving concern of the Industrial Customers we work for. So it's not something that I've been up all night thinking about. We've tried to be of help to the extent we can.
MR. BOWMAN:
A. I guess to expand on that a bit. The demand energy rate seems to have some benefits in terms of solving some problems that are relevant to the Industrial Customers. In the end, they may not be the only way to solve those problems. Industrial Customers may be able to have things like the stuff we're talking about here, in terms of price signals or that addressed another way. So it's not a

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huge concern as far as we understand it, and from us personally, that the bill that gets mailed to Newfoundland Power has two lines on it, one that says energy and one that says demand rather than just one that says energy. The core of the issue as to what that looks like is not something that we're particularly concerned with. It's the fact that a bunch of these other considerations, in terms of price signals and load forecasts and rate striking costs and that sort of thing seem to be solved by what seems to be a relatively straightforward and moves--that puts Newfoundland Power in a more consistent footing with other types of distribution utilities.
Q. But within your experience, do most jurisdictions with large wholesale customers, such as Newfoundland Power, have wholesale rates with both demand and energy charges?
MR. BOWMAN:
A. I would think that would be the norm. I can think of at least two examples that don't and it may be that the exceptions prove the rule in this case. One of the examples that

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doesn't is a system where wholesale utility is basically only buying surplus hydro power, despite the fact that they have enough thermal generating capacities to supply their whole load. They're buying an Interruptible sort of energy-only basis because it's cheaper than running their own units and the other utility has surplus hydro. That one has an energy-only rate, but it reflects the specific circumstances that are there.
The other one that I'm aware of that has an energy-only rate is up in Yukon where there had been a demand energy rate in place until the period where the distributor became the manager of the assets for the wholesaler and suddenly the distributor's rate was switched to an energy-only rate. So they're two notable exceptions.
MR. OSLER:
A. That last one, the distributor is not managing that system at the moment, and the matter may come up for review at the next rate hearing, so they may be asking some people from Newfoundland to come to Whitehorse or something, since you guys have had more

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experience debating this.
Q. And that's where--in the Yukon, is that the same place where baseboard electric radiation is outlawed?
MR. BOWMAN:
A. Well, it would be on different systems, but it's the same place, yes.
MR. OSLER:
A. To be very clear, if you're dealing with isolated diesel system in Yukon or the Northwest Territories, you know, Old Crow in
MR. OSLER:
Yukon and there's some other ones, that's what Mr. Bowman's referring to. There is baseboard heating in the Whitehorse Aishihik Faro grid system in the Yukon where there is hydro as the dominant source of supply and actually, given the closure of their large industrial customer, it's not only the dominant source of supply, it's basically the only source of supply because they don't need to run any diesels at the moment. So that system is where the issue of electric heat had been debated through time. When the dominant industrial customer had been operating, they

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were running diesels on the margin all year round, just like you run Holyrood. It seemed to be very inefficient to have electric heating.

BROWNE, Q.C.:

Q. But I gather that your answer is that it's the norm for large wholesale customers, such as Newfoundland Power, to have wholesale rates with both demand and energy charges?

MR. BOWMAN:

A. That's my understanding, and not having done any sort of detailed survey on this, but that seems to be the type of conclusion that one comes to, based on reviewing this issue.

Q. In your opinion, is there a need to carry out a marginal cost study before implementing a demand energy rate?

MR. BOWMAN:

A. I don't see the link between the two, in terms of the items we just talked about in regards to the demand energy rate. The marginal cost study doesn't change the fact that most other wholesale or retail utilities seem to face this type of rate structure. It doesn't change the fact that there will be some form

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of price signals. Someone may argue whether they're exactly the right ones, but right now, there's no rate related price signal regards to peak loads, so it's hard to know what's there, in terms of DSM that could be easily accomplished. So I don't necessarily see the link.

Q. So your answer is no, it's not necessary to carry out a marginal cost study?

MR. BOWMAN:

A. I don't think it's a reason to delay implementing a demand energy rate.

Q. And it's true that the Industrial Customers have a demand energy rate without the benefit of a marginal cost study? That's true, isn't it?

MR. BOWMAN:

A. Yes.

Q. Would Hydro and its customers benefit from a marginal cost study?

MR. BOWMAN:

A. I think that there's room to talk about a marginal cost study being of benefit to Hydro and its customers in certain aspects. There's different ways that marginal costs are used in

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different types of jurisdictions. The one that is very common, and I think is very relevant to the system is in terms of DSM, in terms of things like determining the value of the various DSM programs and how much benefit they may provide over the long term or things like Interruptible B, when we talk about Manitoba and the evidence that Mr. Osler refers to being filed in an RFI at the '98 hearing that he was in in Manitoba. That was all related to Manitoba Hydro's marginal cost study and how one moves from that to valuing the curtailable loads. So there's a lot of places where it probably would show up as particularly relevant in regards to that DSM side, for sure.

Q. And would a marginal cost study help to determine the benefit of something like Interruptible B?

MR. BOWMAN:

A. Well, yes, that's what I was saying, that in many cases where one talks about that type of rate, it's in terms of benefits that are measured by a marginal cost type study, yes.

Q. I think we could stop there, Mr. Chairman,

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until what time?

CHAIRMAN:

Q. 1:30 we'll reconvene.

BROWNE, Q.C.:

Q. Okay, thank you.

CHAIRMAN:

Q. Thank you.

(LUNCH BREAK 12:25 P.M.)

(RESUME - 1:33 P.M.)

CHAIRMAN:

Q. Thank you. Due to some commitments by the

CHAIRMAN:

panel members, we will break at 4:15. We will end at 4:15 today. We have a break scheduled for 3:15, which we could probably do at 3:00. We'll take our 3:00 break and then we'll terminate at 4:15, if that's satisfactory, please. Okay. Anything else, Ms. Newman?

MS. NEWMAN:

Q. No.

CHAIRMAN:

Q. Mr. Browne, when you're ready please.

BROWNE, Q.C.:

Q. Yes, good afternoon. There was evidence given in this hearing that after Granite Canal, the

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only major hydrology by way of a major project left will be Island Pond, which I think can give us 36 megawatts. You've mentioned Island Pond in your evidence earlier today. Given that that's where the province is headed, do you believe now is the time to look to address what could be a potential shortage from a hydrological source down the road?

MR. BOWMAN:

A. I would say from the perspective we're coming from, the long-term picture here is today there's sufficient capacity on the system and energy on the system that looks to be continuing to exist for some period of time, six years, as what's in our evidence. That may have changed slightly with the wind project being brought in, and some different factors going on, and at that point, someone would need to look to add something to the system. Presuming that's Island Pond and it's the last opportunity for hydraulic, it may mean that one gets into problems the next time you need an addition past that. But there's-- it's not irrelevant just looking at the problem that arises that leads to the need to

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bring Island Pond in if, as I understand from when Mr. Haynes was up here, it's higher cost than the type of resources that are there now. Bringing on a higher cost resource to a system that has rates of the type that's here, you know, an average cost raises the cost for everyone.

So shortage of hydraulic resources would be one reason to think about the type of planning that you put there, but even in a shorter term, where there's more than enough to get us to Island Pond and a bit beyond, you know, on that sort of say six years to the addition and until the next hydraulic after that is required, the same impetus is probably still there. These things don't turn around quickly. If you're going to try to reduce loads, it takes some time for people to respond and so there's a need to be planning to do that and have that in place well in advance of when you're seeing that type of shortage that you're talking about.

Q. Are you aware that during the hearing, Hydro witnesses told us if the metallurgical facility goes ahead at Voisey's Bay in the

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Argentia area that all of the capacity of Island Pond, the 36 megawatts plus they will need other, other sources will be used with that one project. Are you aware of that?

MR. BOWMAN:

A. I know that I would be commenting from the perspective of reading the evidence of Mr. Haynes at that Table 8 that we had up earlier that shows the peaks on the Island and the energy on the Island and where the next plant is required, and rather than the type of gradual growth that you would normally see where when the next plant is required can move a lot, there's a gradual growth and then you get clobbered by a large load coming on, in terms of the numbers that are there. So whether that means Island Pond needs to be built for Voisey's, I don't know, but the point out of that type of long-term load forecast is that a large load coming on stream seems to be the thing that's driving the next plant investment.

MR. OSLER:

A. But the specifics of your question, I think were would Island Pond be sufficient to meet

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the Voisey load. I don't know whether--I gather from the transcript that somebody said the Voisey load would be in the neighbourhood of 50 megawatts and requiring about 400 gigawatt hours a year. So from the information that sort of is casually available to one without getting into the detail, I wouldn't be surprised that somebody testified saying they needed more than just the one facility. But I didn't--I haven't read it over and I don't know that to be a fact that

MR. OSLER:

it be the type of detailed planning you'd like to see somebody doing sooner rather than later.

BROWNE, Q.C.:

Q. Have you had any experience in assisting utilities with a conservation program with the particular objectives to bring down the number of megawatts that are used system wide?

MR. OSLER:

A. Specifically us doing the assistance to the utility to do that, no. Being involved in processes where utilities are dealing with that, in terms of the DSM game plan, yes. The

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capital hearing in Manitoba in the late 80s, early 90s, they were introducing demand side management at that time and there was considerable debate. In the Yukon, similar debate in the first half of the 1990s. So it's not a subject one's unfamiliar with at all, but we haven't been responsible for advising people exactly how to do it or how to implement it.

Q. From your experience in Manitoba that you mentioned, was there a specific objective target to bring down the number of megawatts used in the system?

MR. OSLER:

A. There were very specific targets that were developed, as I recollect. I don't have it, by any means, at my fingertips, and they were based on a percentage of the system's forecast requirements, both capacity and energy, and they came up with some--a very material part of the discussion was over the reasonableness of the targets, those who thought they should be higher and those who thought they were more than enough ambitious. Then they had to then break down the game plan as to how they would

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achieve that. I think we're about to go into the same type of debate right now in Manitoba with a hearing that's about to start early next year, and there's a considerable interest in some new evidence being brought forward and a new study, I think, that Manitoba Hydro has just tabled on demand side management and I presume we'll go through the same discussion all over again, the extent to which the targets are conservative versus could be bumped up. So yes, in general terms, when I've seen people do this type of thing, they have come up with targets that are usually based on analysis of the loads and the system and where they think potentials are and what it would cost to get them and whether those costs are effective and efficient in the light of the system's cost structure.

Q. In your evidence on page 45, you make reference to Exhibit RDG which summarizes a number of the aspects of the two-part rate that require examination, and you address a number of those, including the price signal, revenue stability, neutrality and the NP generation. In your opinion, can all of these

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issues be readily addressed in this particular hearing by the Board in its decision?

MR. BOWMAN:

A. Well, there's certainly information, as I've seen, information on the record in regards to each of these topics. So I don't imagine it's impossible to find a way through solving all of them. I haven't followed in detail all of the different debates that have gone on in regards to the very technical aspects of how to design and implement that rate.

Q. There's a reference made to the sample rate as part of the body of evidence, and does the sample rate, in your opinion, send an inappropriate price signal encouraging Newfoundland Power to modify its hydraulic storage patterns to reduce costs?

MR. BOWMAN:

A. I think our concern would be that whatever rate gets developed doesn't send that type of price signal, and one of the things that we flagged was that the type of sample rates that were developed in terms of their treatment of NP's generation went a long way down that road of saying how do we prevent them from gaming

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the system. As we looked at it, and said, you know, a valid concern is how to prevent them from gaming the system, it struck us that the various types of rate designs that were being talked about looked at a very technical way to prevent that when it didn't seen necessary given that there's a very clear legislative prevention of that. That Newfoundland Power seems to be--there seems to be a direction under the EPCA that very clearly says the Island should be operated on the basis of the

MR. BOWMAN:

lowest cost to all customers and I would think a reasonable implementation of that ensures that nobody can game the system to undermine that policy objective to their own benefit.

This is identified in Mr. Brockman's supplementary evidence. He notes a concern that the wrong rate structure might send Newfoundland Power something that encourages that type of activity, that they might have an incentive to game the system within the rate. But it seemed to us that whether you're talking the sample rate that's developed or some other option for that, the key is there

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should be a credit that provides a normalized, some sort of normalized hydraulic credit, no credit for the thermal, and the peak is only-- only that part is netted off. That would be an improvement on the sample rate to ensure that that gaming incentive isn't there, and to ensure that there isn't an opportunity for them to undermine the policy objectives that are in that piece of legislation.

BROWNE, Q.C.:

Q. You use the term "gaming the system." What do you mean by that?

MR. BOWMAN:

A. Well, at any--within the context of regulation, there's the ability for the utilities to recover the cost that they incur, subject to those costs within that type of policy we're talking about being as low as possible within the system that's here. By gaming the system, I mean an opportunity for one customer or utility to operate the system less efficiently to undermine that policy objective, but as a result of doing that, somehow profit or lower their own costs. It's to basically work within sort of a

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mathematical formula or mathematical calculation of a rate to bring their own rate down, despite the fact that it's increasing costs overall.

Q. And how are you tying that in with hydraulic storage patterns?

MR. BOWMAN:

A. What I'm saying is that if Newfoundland Power is going to be a demand rate based on the demand peak they send on the system, there are two ways that they can ameliorate that peak, both of which would, in fact, raise costs on the integrated system, on the total combined cost that the Island Interconnected System incurs. One is to change the way they use their hydraulic generation, which would--to encourage spill at other times or to result in Hydro having to spill water or somehow increase the cost of the system in order to curb their peak so that they can get the benefit of a lower peak on the system. And the other is to dispatch their thermal, even though it's not the lowest cost generation, to curb their peak at those very short periods of peak time in order to benefit from the rate.

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And like you say, Mr. Brockman highlights that concern and we've highlighted it as well.

Our point is you don't have to net all their generation off and give them the benefit as if they ran it in order to prevent them from the need to run it. You would have to say, consistent with the legislation that's in place in this province, we'll put in place a rate that doesn't need to net it off and doesn't allow it to be netted off. All that will be netted off is a normal amount of hydraulic generation that's consistent with their plants, no dispatch of thermal generation because that's not planned for in the year, and use their actual peak less that normalized hydraulic, in terms of the peak that's used for their billing purposes.

Q. When I hear a term like "gaming the system" it sort of raises other issues. Are you suggesting that there will be a way around the demand energy rate or the peaking that--what are you suggesting here?

MR. BOWMAN:

A. The rate that's in place, whatever rate gets developed, shouldn't allow the ability for

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somebody to raise the cost on the system by the way they operate their generation, but by doing so, lower their own costs. In other words, shift those costs over to someone else. That would be, you know, inappropriately finding mathematical variations or almost use the word "loopholes" within the rate structure. The idea being, you know, for example if a rate is developed--what I recall of the RDG-2 exhibit develops a two-part rate. One that's at a lower cents per kilowatt hour,

MR. BOWMAN:

one that's at a higher cents per kilowatt hour. It's designed on a particular load pattern. If somebody decides that as a result of that particular rate structure, we can reduce the number of high cost units we buy and increase the number of low cost units we buy by shifting when we use our water, even though that's undermining the system, we're profiting from it. That's what I mean by gaming. That type of result shouldn't be allowed to result in somebody's ability to profit from the system.

BROWNE, Q.C.:

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Q. Some general questions. Is it a widely accepted practice, consistent with the principle of ensuring rates reflect costs, to signal costs separately in customer energy and demand charges, where practical to do so? Is that a commonly accepted rate design practice?
(1:48 p.m.)
MR. OSLER:
A. Your question included customer costs as well as demand and energy?
Q. Yes. I'm into principles now. I'm into signalling.
MR. OSLER:
A. Generally speaking, where feasible, in the sense of metering and other things. It's common to reflect the three factors you've noted, which come out of the system's costs. The cost of serving the customer is distinct from the cost for serving the capacity versus the cost of serving energy and reflected in rates, where feasible.
Q. Where there's a system with an energy only rate, what incentive is there, in this particular jurisdiction, for Newfoundland Power to engage in demand side management

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activities that reduce load?
MR. BOWMAN:
A. Well, there's--the incentives would all be in terms of the bill they pay to Hydro. In a sense, it would all be on the energy side, not on the demand side, within the rates that they pay. Within the--because there isn't the price signal in terms of the demand peaks that they set, in terms of the bills that get mailed out each month.
Q. So on the energy, using the energy only rate, there's--would you say there's little incentive for Newfoundland Power to engage in demand side management activities?
MR. BOWMAN:
A. Well, I guess--I want to be careful here. If we're talking about incentive in terms of is there a possibility that they could reduce their costs more than they reduce their revenues, there's probably very few because to the extent that energy use goes down, there's probably lost revenues to Newfoundland Power that are greater than the lost--of cost that get flowed through to Hydro, to the extent that they can curb their peak. There's no

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savings in terms of the bill that we're talking about. There may be saving--what I'm saying with demand side management, there may be ways to go out and reduce the line losses so that you're buying less units that get lost. There may be ways to reduce the, you know, service to power that they use themselves. Those type of demand side management activities have a certain price signal, but in terms of saying we want to find a way for our customers to use less kilowatt hours or to use a lower peak, there's not a lot, if any, price signal in terms of what's there right now.
Q. But if there was a demand and an energy rate, would we see then some incentive for them to engage in demand side management activities?
MR. BOWMAN:
A. I want to be cautious about--demand side management is not normally thought of as something that utilities jump up and down about and get real excited about. It's usually something that's more thrust upon them, in terms of their normal way of thinking about it. Because in general, there's not a

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lot of profit motivated, if I want to be that simple, types of incentives to get involved with demand side management. Moving to a demand energy rate would send a better price signal so that people sitting in this room in a Newfoundland Power GRA, I presume it's this room, can sit there and know that curbing their peaks will reduce the overall cost that customers have to pay immediately on the bills. That type of incentive becomes clearer in the pricing sent to Newfoundland Power.
MR. BOWMAN:
I'm not convinced that it's going to, you know, cause a big incentive for Newfoundland Power to run out and start a big demand side management program on their initiative, in and of itself, if that's what you're asking.
BROWNE, Q.C.:
Q. In terms of matching, is it a regulatory principle to match the distinct cost causation effects pertaining to demand and energy?
MR. OSLER:
A. Yes, to the extent that you can through, where feasible, through assignment of costs to demand and energy and then tracking it through

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rates, so that if somebody changes their consumption of demand versus their consumption of energy, they see the cost tracked differently. Essentially, why you set a rate is to try and track costs based on consumption, as distinct from just sending the guy a bill for the year, if you got really simple about it. We could take the whole bill for the year and divide it up and send everybody one bill for the whole year. That wouldn't be very fair. So we start trying to track how much this person used versus that person. The heck with what was forecast, how would you track it. And then demand versus energy is just a sophistication that you add to that in case somebody's load varies based on demand versus energy. It's not, in principle, complicated. It just gets complicated in practice.

Q. In reference to the Burin Peninsula and whether or not these assets be assigned to common as proposed by Hydro, we had the experience, which I'm sure you're familiar with and you've seen in the evidence, of a power outage some months ago, in which the

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resources of both the Burin Peninsula and the Great Northern Peninsula were called upon to assist the common good. Would that not, in itself, be persuasive evidence that these assets be assigned to common?

MR. BOWMAN:

A. No. In the Burin Peninsula, what we're talking about is a transmission system that is, in principle, very similar to the GNP transmission system and this type of relationship was reviewed and discussed back in the 2001 hearing, and it's not determinative that the generation at the other end of the line being a benefit to the Island system results in the transmission necessarily being assigned to common. The GNP, in fact, went exactly the other way. What we're saying is in terms of Burin, if anything, that same cost type of drivers are pushing it the other way.

Q. But you can see some merit in an argument from a layperson such as myself that because they helped us all out that there's some common element there? Would you not concede that?

MR. BOWMAN:

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A. Well, I would concede that these are not absolutely black and white issues. On the GNP generation, which more goes to "is this generation of use in meeting peaks." The evidence is when you look to the generation itself, it can, in certain circumstances, help meet peaks, but by and large, the generation that's there is serving the local loads for things like transmission outages. In the case of transmission, it's an entirely different argument. It's a matter of is this transmission primarily being there to interconnect some generation at the other end to the grid for the benefit of the grid or is it really primarily there to serve a bunch of customers who live near the end of a lateral system, and I think the evidence is to the latter, that the transmission is built and maintained and justified on the basis of providing service to some customers. That there happens to be some generation down at the other end that can support the system may lead to a different thought in terms of how generation is assigned, but it certainly doesn't get you through the door in saying the

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transmission is of common benefit.

Q. In reference to the mediation report, if we can go to the items not agreed upon, I think that was Consent 1, and if we can go to item O? What's your position regarding the treatment of Newfoundland Power's thermal generation?

MR. BOWMAN:

A. Our position is that the current treatment that's proposed in the cost of service results in the Industrial Customers and Rural

MR. BOWMAN:

customers paying 60 percent of the cost of those units, which completely is not consistent with the benefits that those units at all provide to Newfoundland Power's customers or the Island Interconnected grid and the relative level of each.

BROWNE, Q.C.:

Q. Would your answer be the same if there was a change in the wholesale power rate to a demand energy rate?

MR. BOWMAN:

A. Yes.

Q. In reference to Item U there, it relates to

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the demand charges for interruptible power above the power on order for Industrial Customers. What is the basis for the demand charges assigned by Hydro for this type of interruptible power?

MR. BOWMAN:

A. This is an item that we haven't gotten into covering today. It's--Hydro's proposal has been changed in the latest Banfield evidence to reflect agreement between the Industrial Customers and Hydro that would not have demand charges for interruptible power, but would have an energy only rate. Our understanding of the demand charges that were put is a relatively arbitrary level of cost recovery from customers. I don't have the quote in front of me. It's somewhere in here, but to reflect a contribution to the system or something of that nature.

Q. That's fair enough. Item X there makes reference to the marginal cost study that Hydro has proposed to undertake or the Board may order undertaken. Should the Industrial Customers, Newfoundland Power and the consumers all have the opportunity to review

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and comment on the terms of reference of any such study?

MR. BOWMAN:

A. I would think that in terms of having a study done that's going to be in at these type of hearings, it's probably further ahead having something that's got a little more input at the outset. I think that the input that's going to be required though probably goes beyond the terms of reference. It's probably also going to be a fair amount of information required from say the Industrial Customers. I'm sure that in order for someone to sit down and do a marginal cost study, they're going to need to talk to some of the big users on the system and just, you know, where they're going and what they're planning. So I imagine it would be somewhat iterative and have participation throughout if it's going to end up in a useful product.

Q. So you would see it as a collaborative effort?

MR. BOWMAN:

A. I think it would probably -

Q. Among all the stakeholders.

MR. BOWMAN:

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A. I think it would be of more value and less contentious by the time it makes it here if a marginal cost study were to be undertaken for the purposes of, you know, for example, planning DSM, that there's some opportunity for participation rather than it gets sort of bounced on the desk with the next GRA that gets filed.

(2:00 p.m.)

Q. And if any such study is ordered and following the study, should all these participants have the opportunity to review and comment on the study, following its filing with the Board, in your opinion?

MR. BOWMAN:

A. My impression is that in terms of a utility being sent off to do studies that actually get somewhere, it's further ahead to the extent that some clear direction is provided for the level of consultation or the level of interaction with customers as opposed to it just being done internally by the utility. The more of that consultation and interaction, the further it may go. For example, to use the one that we spent some time on this

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morning, Manitoba's version of Interruptible B, the curtailable rates. That was the utility was sent off to work with customers on a working group towards how a rate like that could be implemented and they came back with one, in between GRAs. It wasn't just a mediated settlement outside of the--within a GRA filing. So that type of thing, from what we've seen, can result in some progress outside of this type of forum. It would seem to make sense in terms of the marginal cost

MR. BOWMAN:

study you're talking about as well.

I would also note, as I've understood the marginal cost study to be discussed here, one of the people--I believe your list included Industrial Customers and Newfoundland Power. I have trouble imagining how Newfoundland Power wouldn't be part of a marginal cost study that's intended to deal with the Island Interconnected System. Like it clearly would need some level of interaction from them that may be different and special compared to say the Industrial Customers.

BROWNE, Q.C.:

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Q. But because it's Hydro's marginal cost study, the study should be essentially undertaken by Hydro, as opposed to Newfoundland Power and the Industrial Customers or ourselves? Would you agree with that?

MR. BOWMAN:

A. I think in terms of the hearing that we're here to deal with today and the Board Order coming out of this, it would need to direct Hydro to go off and do the study in consultation with the people. I don't think it'll direct the Industrial Customers to do it.

Q. These are our questions. Thank you.

CHAIRMAN:

Q. Thank you, Mr. Browne. Thank you, gentlemen. Good afternoon, Mr. Kelly.

KELLY, Q.C.:

Q. Thank you, Chair.

CHAIRMAN:

Q. When you're ready, please.

KELLY, Q.C.:

Q. Good afternoon, Mr. Osler and Mr. Bowman. I had a look at your education and qualifications in attachments A and B

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respectively, and if I look at that, would you agree that your education and training is primarily in the field of economics? Would that be fair?

MR. OSLER:

A. Certainly would be in my case.

MR. BOWMAN:

A. Mine is a little bit more applied, but yes, primarily in economics.

Q. So neither of you are systems planning engineers in any respect?

MR. OSLER:

A. That's is definitely correct.

MR. BOWMAN:

A. That's correct.

Q. So you'd agree with me that Mr. Haynes, Hydro's vice-president of production, would be in a better position to tell us about system operating characteristics and system planning for the future?

MR. OSLER:

A. I would hope so.

MR. BOWMAN:

A. Agree.

Q. Okay. I thought you would. Let's have a

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quick look at page 36 of Mr. Haynes' pre-filed testimony. I want to be sure we're on the same understanding of criteria to be used here. Now Mr. Haynes sets out the two criteria which govern Hydro's planning, and the first is the energy criteria and that the system should have sufficient generating capability to meet all of its firm energy requirements with system capability, and Hydro's counsel this morning took you to the table of the firm capacity. Do you accept that energy criterion as appropriate?

MR. OSLER:

A. Yes.

Q. And is that criterion commonly applied in your experience?

MR. OSLER:

A. As it's stated, it's sort of true by definition, the practical issues that arise as to how you define firm energy with a hydraulic system and when you have systems that go back and forth. So yes, it's commonly stated with a lot more elaboration as you get into detail and different systems.

Q. Okay. Now the second criteria is the capacity

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criteria, and that is that the system should have sufficient generating capacity to satisfy a loss of load LOLH expectation target of not more than 2.8 hours, and do you accept that criteria?

MR. OSLER:

A. I accept it for the purposes of the discussion and have no reason to challenge it.

Q. Okay. And that type of criteria, is that commonly applied?

MR. OSLER:

A. It is applied in different systems and some systems don't use it as their determinative approach to define when they need new capacity. So it's not as straightforward as the first one.

KELLY, Q.C:

Q. Okay. You would accept it's reasonable in terms of Newfoundland's Interconnected system?

MR. OSLER:

A. Again, I'm not an expert in which approach they should take in the Newfoundland system. I just accept it as the one that they're taking and I presume it's soundly based and I

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have no reason to believe otherwise.
Q. Okay. Can we go to Table 8 then of the criterion or of Mr. Haynes' evidence? And in this particular table, it shows the various forecast loads from 2003 through to 2012 and if we look at just 2004 for a second, there is an LOLH factor, loss of load hours, of 1. 1 hours? Do you agree with that?
MR. OSLER:
A. That's what the table shows, yes.
Q. Right. And then that increases all the way down over the years until we get down to 2011 where it has reached 3.5 hours and the criteria is exceeded, agree?
MR. OSLER:
A. Correct, that's what it shows.
Q. Okay. Now so at some stage along the way, it is necessary to add additional generating capacity to Hydro's system, and would you agree with me that any generation which is added to the system goes in as a block of generation? It doesn't go in one megawatt at a time?
MR. OSLER:
A. Yes.

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Q. And for example, if Hydro were to go out and do a review and determine the various sources of supply and determine a least cost alternative and it decided that well, project A was the least cost alternative and they added, say, 50 megawatts to the system, that would improve both the energy balance and the LOLH criteria? Accept that?
MR. OSLER:
A. I accept that.
Q. Now, if that generation addition, would you agree, adds long term benefit to the system?
MR. OSLER:
A. Well, I mean, just looking at the table we've got here, this is where the issues start to get not quite as straight forward. There's a very big jump in some issues in 2012 associated with some of the things we were talking about a bit earlier to do the processing facility. Adding a 10 gigawatt hours worth of energy in 2009 or whatever is needed to make 2010 might look pretty silly by the time you get to 2012, if you haven't done some long term planning, comparison of options and everything else. So, system planning,

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beyond looking at these indicators and as the LOLH, last time we were here a couple of years ago, wasn't adequate, didn't mean that anybody turned off all the lights. It just meant that they had an LOLH greater than 2.8. To get into what should be done next in this system is a long term planning and options assessment that goes way beyond looking at this table.
Q. Okay. And I accept that answer and what you just said is, we would need to look at long term planning and the system options, in other words, the type of options for the next generation capability?
MR. OSLER:
A. Correct.
Q. Correct, okay.
MR. BOWMAN:
A. I would just add that presumably, it would also be in addition to the type of things that might be done to remunerate the peaks or energy there, in terms of a resource available to meet those peaks, maybe building something or it maybe taking on a DSM type program; they both can help -
Q. Like your curtailable Interruptible B?

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MR. BOWMAN:
A. Yeah. Long term capital hearings have often dealt concurrently with both the DSM planning and the generation planning to see what's the best balance for the system.
Q. So, if we looked at some of the things you just said, we need to look at the time frame over which that is needed and we need to look at what are the available capabilities options, expanding the capability and you'd want to look at what are the available
KELLY, Q.C.:
options, for example, like interruptible industrial rates, all of those factors, agreed?
MR. BOWMAN:
A. All of those and probably more, yes.
Q. And probably more, okay, I accept that. Now, just come back to my question about adding the--let's say you made the decision, you're going to add a block, that then adds a block of generation capacity. Can I suggest to you that that doesn't make any of what is already there unuseful. It all still has a purpose on the system. Do you agree with that?

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MR. OSLER:
A. It doesn't change what's there. It may change in terms of physical assets. It may change the ordering of when certain plants are called upon to be used. It may change the extent to which some of them are used as much, therefore, et cetera, in terms of energy use. All sorts of things like that, that means--the plants that are there are no longer necessarily operated the exactly the same way as they would have been without this new block as you call it.
Q. But it doesn't mean that they're no longer used and useful?
MR. OSLER:
A. By itself, it doesn't, no. Although, I can think of situations where it might, but that's just--it doesn't automatically. You have to have some reason that showed that it had made redundant some plants -
Q. And if you had capacity that existed on that system in the form of thermal units or whatever and you added this new block, it would not make good economic sense to take a plant, good useable plant out of service and

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then have to come back and replace it four or five years down the line, would it?
MR. OSLER:
A. Generally speaking, it would not make sense to be doing what you just described.
Q. Right, okay. Now, if I take you to your pre-filed evidence at page 28 at lines, at the very top of the page, at lines 1 and 2, you talk about the current 2004 test year generating compliment represents a plant in excess of that determined to be required by Hydro to service the Island Interconnected load. But I take it from what you just said that all that you're really saying there is, well, it exceeds the 2.8 LOLH factor, correct?
MR. OSLER:
A. Correct.
Q. You're not saying that the plant is not, in fact, used and useful?
MR. OSLER:
A. Definitely not saying that, no.
Q. Okay, good, I just wanted to be sure we got that right. Now, can we go next to JRH No. 3 which is the Hydro's study. And if I take you to page 5, Table 2.1. And that table shows

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the various generation assets which are on the Northern Peninsula, Doyles-Port aux Basques and Burin Peninsula line. And the total, we've got 15.1 in the first block, 15.8 in the second block and 34.7 in the second (sic.) block, the total is 65.6 megawatts in total. Now, some of that is Hydro's and some of that is Newfoundland Power's, do you agree?
MR. BOWMAN:
A. Yes.
Q. Now, we go to Table 3.3 on page 12, what Mr. Haynes has done there is he has set out the impact of taking those various items off the system. And if you look at deleting all of them, in 2004 you'd have an LOLH of 3.5 hours, correct?
MR. BOWMAN:
A. As I understand it, this table takes the current system as it's configured including all the interconnections and simple removes the generation that we just talked about, sixty somewhat megawatts and it comes up with 3.5.
Q. So, all of those generation assets, whether they are the Hydro plant, hydraulic plant in

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Paradise River or the various thermal plants on the Northern Peninsula are actually used and useful in the meeting that LOLH criteria, aren't they?
MR. BOWMAN:
A. Well, given the configuration of the system that there's right now including all of the various interconnections, those plants assist in meeting the LOLH criteria.
Q. Okay. And one of the questions that Industrial Customers asked was question 336,
KELLY, Q.C.:
IC 336, and this question provided, in essence, what would be the situation if the 15 megawatt gas turbine on the Burin Peninsula throughout the--in the situation with the turbine moved elsewhere. And you may be familiar, that's the one that we talked about earlier, in Salt Pond. Well, if you go to the table with that one, there's a table at page 3.3, page 3 of 3 of that--here we go--and in fact, that would give you, in 2003, a 3.1. So, all of that generation capacity including that unit as well, is important in meeting the LOLH criteria?

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MR. BOWMAN:
A. As I understand this table, it's saying that the--if you took all of these, sort of, 65 megawatts we just talked about plus another 15 and removed them from the system leaving the rest of the system configured as it currently is, the LOLH criteria would be 3.1 in 2003.
(2:16 p.m.)
Q. Right. So, all of that generating capability is required for the system operation. Now, can I take you to pages 15 and 16 of JRH No. 3. And there's a discussion there at the bottom of the page and Mr. Browne alluded to that earlier. "Since 2001 the value of reserve capacity was demonstrated on at least 2 occasions, on January 30, '03 the diesel units at Hawkes and St. Anthony were operated in support of the Island Interconnected system following the failure of lightening arrestors at Oxen Pond terminal in St. John's. The subsequent trip of all three units at Holyrood, GNP generation was brought online to aid in system restoration". And then they go on to talk about January 31, 2002 when the interconnected system was at an all time peak,

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all three units at Holyrood were operating near full capacity, hydraulic production on the system was near capacity, et cetera. And they talked about in preparation for that, Hawkes Bay and St. Anthony were tested to ensure availability.
So, all of those thermal systems including Newfoundland Power's thermal system provide the capacity to the system that is needed both for capacity and reliability. Would you accept that?
MR. BOWMAN:
A. Given the system that is there today, those units were used on those two occasions and I understand there may have one or two yet since that time.
Q. Okay, all right. So, that ability to meet capacity, in fact, assists the Industrial Customers, doesn't it?
MR. BOWMAN:
A. Only within the constraint that I've note, that given the system that's there today.
Q. That's what we have to deal with though, the system that there's today. In other words, if there was a problem on the system tomorrow,

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all of that capacity could and would be called on as needed to meet interconnected load including the load of the Industrial Customers?
MR. BOWMAN:
A. Yes, including the load of the GNP, including the load of Burin, including all of those loads.
Q. Right.
MR. BOWMAN:
A. Because it's a basket of loads that is interconnected to the system and all of the generating plant could be used in certain circumstances in order to meet the LOLH target that's set out in the Haynes table.
MR. OSLER:
Q. Just to be very careful, you're looking at all these loads that are distributed, there's nothing in the comment about looking at LOLH numbers for the system, to suggest that the individual radial systems don't need to have, for reliability purposes and capacity, down at the end of those lines, don't need to have these facilities. That's not the type of assessment that's being brought. Proving that

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they are useful to the radial systems does not show that they can send electricity out from the loads that they are serving when they're being used down in those systems and provide effective and useful and cost effective energy for the industrials who are back on the main system. The information we're looking at doesn't really go to the heart of the issue that is at question.
Q. Okay, but you agree with me that they are all useful for meeting the capacity on the overall
KELLY, Q.C.:
system? Do you accept that, first of all?
MR. OSLER:
A. Yes, in the context of exactly what I said, yeah.
Q. But if, in fact, that generation, whether it's a plant on the Northern Peninsula or a plant down in Port aux Basques, meets a local load down there at a time of system peak, that enables other plants elsewhere on the system to service the Industrial Customers. In other words, you can't look at it as simply isolated little blocks, can you?
MR. OSLER:

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A. Well, you can and you do and that's why the Hydro study comes to the conclusion, the GNP shouldn't be assigned a common. And when you make that conclusion based on the logic, the same issues arise with respect to generation. So, with respect to the electrons can flow, it doesn't prove that the cost should go with them. And the fact that you built the grid, extended it then with the GNP and had some generation at the other end of it, all of those are true, but they don't prove how the cost should fairly and efficiently and effectively be allocated, which is the issue at stake, with the generation or the GNP transmission.

Q. If that -

MR. BOWMAN:

A. Sorry, what we're discussing here is this very simplistic test that says, does turning them on make it better than turning them off? That's the type of test that we talked about in 2001 and was rejected in regards to the GNP transmission. The point in that regard is, does--by running this transmission up the GNP, is everybody better off or worse off. And in

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the end, the evidence is that everybody who is also on the system is worse off. They're not better off because there's a plant up there. Yeah, they're better off if there's plants up there given that there's load up there, but the truth of the matter is the GNP interconnection that was designed to serve rural customers degraded power quality on the system. So, it's not like those diesels up there are these big boom to the people who are remaining on the system. Overall, that was a degrading to power and that's set out in IC 399.

Q. Let's go at it this way. You'll agree with me that all of those generation assets, number one, helped defer generation additions? Do you agree with that?

MR. OSLER:

A. Well, if you start from the assumption you've got the loads on the GNP and the loads on the Burin and they're interconnected and something has to supply them, then having a unit there to supply them reduces the need for that unit somewhere else.

Q. Okay. And they each help meet system reserve

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requirements that result in reduced incidents of under frequency load shedding?

MR. BOWMAN:

A. Well, again with the same caveats that I just set out, yes.

Q. And a assistant system restoration following outages as we just looked at?

MR. BOWMAN:

A. Again, with the same caveats, yes.

Q. Okay. So, in terms of the paragraph that we looked at earlier about excess capacity, can I take you to page 28, line 25, this is of your evidence.

MR. BOWMAN:

A. Yes, I have it.

Q. And at line 25, if you go down to the bottom, you say, "given the current situation of excess capacity until 2011, three matters merit review in this regard". Now, can I suggest to you that in view of what we just looked at, there is really no excess capacity, that all of these plants meet capacity requirements, reserve requirements, system restoration needs?

MR. BOWMAN:

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A. I don't agree with the conclusion. That means that there is no excess capacity. This is something that Mr. Brockman brought up in his Supplementary Evidence as well, that somehow the implication that the test that we've set out is, since we have excess capacity, we can go ahead and think about all these units being not needed which is not correct. All that excess capacity means there is, compared to last time where we were sitting here--and if I go back one page with the LOLH there--last

MR. BOWMAN:

time sitting in this room, the LOLH was like, 3.97 which is well above the 2.8. That's not a time to get into--and in the context of all the other things going on in 2001, that's not a time to get into splitting hairs about the specific electrons on some of these finer points. There's some big issues to be dealt with at that time and the system was clearly in a crunch. We made it through that two years, we're refining the level of regulation, the type of regulation here. It's not in a crunch. Some of the problems have been solved, we understood, like the GNP

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transmission line. Now, we start to say, and where else does that lead us. So, it's not that it somehow hinges on their being so much that the system is overbuilt or any of that sort of thing. It's just saying, given the situation today, where we're not at 3.97 and we're not at exactly 2.8. We're at 1.1, which is considerably better that the target, 2.8. We can take a deep breath, saying, there's six year until we need to add plant, how do we start to look at something over the longer term and refine the regulation of this utility.

KELLY, Q.C.:

Q. Okay. So, your answer is that your reference to excess is not measured against some standard, but simply against kind of where we were in 2001. Is that what I'm understanding you to say?

MR. BOWMAN:

A. No, I'm just saying that the word excess there does not mean over built, therefore, we should ride around writing off assets or pretending they're not useful.

Q. Right.

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MR. BOWMAN:

A. What it means is we're not at 3.97 or we're not at 2.8; we're considerably better than 2.8.

Q. So, having accepted then that they are used and useful within the meaning of what we all understand that to mean, then the Cost of Service methodology was set by this Board in, I think, '93 and approved again in 2002, are you suggesting that that be now re-opened again, the Board having decided that?

MR. BOWMAN:

A. No, not at all. We're just saying used and useful is a test that someone uses in determining the revenue requirement of a utility. Should they be able to recover these costs because they represent assets that are used and useful or not used and useful. When you get the Cost of Service, it's a completely different way of thinking about it which says, fine, they're used and useful, but for whom and what is the relative benefits that arise from them. And the evidence in this regard did not suggest that 94 percent of the benefit of Great Northern Peninsula arises to

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Industrial Customers and Newfoundland Power who are not on the Great Northern Peninsula interconnection. The evidence in this regard is that 99 percent of the time that units are used, it's for the rural customers. So, assigning 94 percent of the cost to non-rural customers, despite the fact they're used 99 percent of the time for rural customers, is not reasonable cost tracking, even if you accept that they're used and useful.

Q. Okay. Now, having accepted that all of these plants are used and useful and we've just had a look at how they provide capacity on the system, let's have a little bit of a look at this Interruptible B issue. If I take you to page 44 of your evidence at lines 17 and following, you make the point in there that looking at Interruptible B should be viewed as a long term process?

MR. BOWMAN:

A. Yes.

Q. And down in line 24?

MR. BOWMAN:

A. Yes.

Q. Okay. And you make a similar comment over on

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page 69. And I don't need to take you there, you can take the point. Interruptible B looks over long-term and generation additions also look over the long-term, don't they, as we've just discussed?

MR. BOWMAN:

A. Yes.

Q. Okay. Now, in NP-136, just put that one up, the interruptible B is 46,000 kilowatts of interruptible capacity available 25 occasions per year at $28.20, which works out to

KELLY, Q.C.:

approximately $1.3 million?

MR. BOWMAN:

A. Yes, it's $28.20.

Q. A kilowatt?

MR. BOWMAN:

A. Annual cost per kilowatt, that is -

Q. Right. It works out annually to about $1.3 million?

MR. BOWMAN:

A. Yes, that's very close.

Q. Now, let's go over to IC-194. And this was the question posed by the Industrials as to what Hydro intended to do. And I'll just take

you down to about line 11. "On this basis"--
well, go back a bit. "An assessment of the
capability of the Island Interconnected System
to meet future load requirements as summarized
on Table 8 of Mr. Haynes indicates that
deficits in capacity are not forecast until
2011. On this basis Hydro has decided not to
renew the interruptible B contract at this
time. Prior to projected capacity
requirements in 2011 Hydro will review the
need and value of similar arrangements and
based on the load requirements and the sources
available at the time." So they say that this
46 megawatts is not needed for capacity at
this point in time. Is that how you
understand it?

MR. BOWMAN:

A. That's what I read there, yes.

Q. Okay. And in fact, they give a similar answer at NP-174? They simply say--no, I got the wrong reference there for you. Let me take you to NP-140. Find the other reference for you after. Now, this table shows the impact of LOLH with that 46 megawatts of interruptible B taken off the system? If we

scroll up the table a little bit. You'll
notice that it doesn't affect the capacity at
all, doesn't affect the LOLH because it's
still 2009 for the energy, of course, which
doesn't change and 2011 for the LOLH factor?

(2:30 p.m.)

MR. BOWMAN:

A. I don't agree that it doesn't affect the LOLH. The LOLH numbers are quite a bit different. It doesn't affect in this case the year that capacity has to be added for largely in response to the processing plant that's been discussed.

Q. Okay. Would you like to elaborate a little bit on that and explain what you mean and -

MR. BOWMAN:

A. Well, just that if you compare these LOLH numbers to those that are in table 8 of the material filed by Mr. Haynes, in that case the 2004 LOLH is something like, I don't have the numbers to quote off the top of my head, but it's not 0.9, it's something higher than that. So it does have an impact on the LOLH. In terms of looking at the year that plant needs to be added, looking at interruptible B in and

of itself does not in some way prevent the
need to add plant to address the processing
plant that we're talking about being added or
it does not in itself address the 10 gigawatt
hour shortfall in 2009 that would start to
trigger the thought of plant in additions.
It's looked at only on just at the
interruptible B in itself.

Q. Okay. Now, out of that can we summarize two points? See if you agree with these? No. 1, that that interruptible 46 megawatts has some impact on the LOLH requirement every year? That's point No. 1 you've made?

MR. BOWMAN:

A. Well, it does have some impact on the LOLH requirement every year. I don't think that would be the basis for talking about renewing it, but it does--in the early years it had some impact on LOLH and in the later years that would continue.

Q. That would continue?

MR. BOWMAN:

A. Yes.

Q. Okay. But when you get to the critical period of 2009, the energy requirement is still the

driving factor, No. 1, and No. 2, it doesn't
do anything on the capacity requirement until
2011, agreed?

MR. BOWMAN:

A. Well -

Q. Still doesn't change the need for new capacity in 2011?

MR. BOWMAN:

A. Well, what I'm saying is looked at in and of itself it doesn't change the fact that a processing plant coming on line in this case

MR. BOWMAN:

in 2011 will drive the need for additional
plant. It does change what kind of plant and
how much plant, but it doesn't change the fact
that there will be new plant needed.

KELLY, Q.C.:

Q. And when you say it may affect the type of plant that is needed, do you think--are you suggesting that there is any change in the type of plant between Mr. Haynes' table 8 originally and this revised table 8, and if so, what?

MR. BOWMAN:

A. Well, what I'm saying is that when one looks

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at generation planning sequences and the longer terms considerations, as Mr. Osler has pointed out, you look at capital planning, you look at both in the context of all those things you can do on the demand side and all the options that are available on the supply side and you consider them as a bundle. In this case, interruptible B only relates to capacity, not to energy.

Q. Um-hm.

MR. BOWMAN:

A. And there are other things that may be available that only relate to energy. A wind plant down on the Burin sounds like a classic example. It's going to provide a certain number of gigawatt hours, but it doesn't give you the capacity you can lean on and ensure it's going to be there when that system needs it. That's typically how wind is thought about. So, when you look at in combination of DSM activities, perhaps some moves to shift people off of electric heat, an interruptible B type program, Newfoundland Power two-part rate, the type of plants that are available, it may materially shift the type of

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considerations that go into the next plant, when it's added, how much is added, what's the plant that follows that. In types of--the types of numbers we're seeing here is if you look through sort of 2004 to 2010 the peak is--and I'm looking at the peak column there, the peak is growing by sort of five to ten megawatts a year. If you can curb that by 46 megawatts from interruptible B, that sort of deals with, under these type of conditions, perhaps five years of normal growth of peak. Once that's complemented on the energy side, it does give you an ability to think about deferring plant.

Q. And you've said it may--all of the factors that you've just listed, and you had a wonderful big long list, you said it may impact the type of plant that is required. Now, how do you determine whether it will or it won't?

MR. OSLER:

A. Well, you'd have to do the do the studies, the long-run studies.

Q. Exactly. You've got to do the long-run studies, don't you? What kind of long-run

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studies, Mr. Osler?

MR. OSLER:

A. Well, we've been through that, mostly on the demand side and the supply side. But I think the essential question, essential issue is to do the planner, the planner should do the proper studies. And for the system and its customers to understand it, they should collaborate and maybe have some--go beyond that. But in terms of making a decision today simply because the LOLH changed and that somebody put together this table based on some assumptions that are there today that you should kill the interruptible B, that's the essence of what we're dealing with and we're not persuaded that this type of evidence is the basis upon which to kill a program that's been there for ten years.

Q. And in that -

MR. BOWMAN:

A. I'd just note that the type of reasoning that says the peak capacity isn't until 2011 and we'll look at it as we get closer to that doesn't seem consistent with the thought that the next 12 to 24 months someone's going to

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have to make decisions about what they're going to do to supply--to address supply constraints, unless something is happening today in terms of confirming the availability of DSM type programs, whether it's interruptible B or whether it's whatever else, action is put on the ground in terms of those, the amount that's available is clarified. There's no way you'll know in 12 to 24 months what impact this can have on the types of decisions that are available to Hydro.

KELLY, Q.C.:

Q. But the items that we talked, we talked about new type of plants or what type of plants will be required, when they will be required, what would be the impact of DSM. Now, one of the factors that you would have to look at in that determination is what are the costs and benefits of each of those options, would you not?

MR. OSLER:

A. Correct?

Q. Correct?

MR. BOWMAN:

A. Yeah, exactly.

Q. Right. Because you don't want to spend money on whether it's a DSM interruptible B program if it's not going to achieve the right objective versus spending money on a plant or vice versa? In other words, you want to know what's the least cost option, would you not?

MR. BOWMAN:

A. That's correct.

Q. Correct. And in order to do that you've got to look at the long-run incremental costs on the system, don't you?

MR. OSLER:

A. In order to look at the type of things to select options, both on the demand side, management side and on the supply side, yes.

Q. Yes. And you -

MR. BOWMAN:

A. I just note that the people who have been in these types of reviews or these types of capital hearings, whether that's the Yukon type hearing or the type of Mr. Osler was referring to that happened in Manitoba in the early '90s or even one that's now coming up again in Manitoba, incremental costs is one of the things, but it's the planning sequences

and the different options that are available and what they supply in terms of energy versus demand and the relative unit costs that are there and the potential uptake of DSM. It's not--all I'm noting is that it's not the, say, the margin cost study that we'd been talking about earlier may feed into that DSM side of it, but it's not, it's not all that's there.

Q. I agree with you. And isn't that absolutely correct what you just said, that one of the things you've got to know is what the long-run planning of the system is, how that long-run planning is going to take place, what are the various long-run incremental options, what are those costs, got to look at the marginal cost of those and then you got to look at other alternatives. But you got to have all that information, do you not?

MR. OSLER:

A. Yeah. Particularly when you're looking at big investments of the type that seem to be approaching with, if you believe these forecasts, these type of numbers you got in front of us. The decisions on meeting that, I presume, will take place relatively soon and

therefore the planning and the analysis, the collaborative discussions would be relatively soon. Hopefully sooner. And all that we're talking about with the interruptible B is a program that year by year costs whatever, one million or 1.3 or whatever it is, and it's being terminated, our point is, somewhat prematurely because you haven't got all the studies we're just talking about and you haven't got all that information in front of us and so--and all we've got is this to look at and on that basis we've suddenly stopped a ten-year program.

Q. So right now we don't have the information to know whether paying $1.3 million now is good value for the money or not, do we?

MR. BOWMAN:

A. Oh, I think it's--I would say it's actually the contrary. We don't have the information to know that it is a reasonable long-term decision to stop providing to a customer to cancel what is effectively a DSM program in advance of a serious well thought out, near term, 12 to 24 months type of review as to the relative role that can play in something.

It's premature to say we don't need it this year, let's stop it. What's more appropriate is to say we won't make any drastic changes on the running off and buying a gas turbine, let's say we won't make any drastic changes in committing to a Hydro plant and we won't make any drastic changes in regards to cancelling DSM programs. But hopefully not very far down the road here in terms of address various concerns that people have in the room about how that peak's going to be met, a bunch of

MR. BOWMAN:

people who's got some planning background and some authority to deal with this and can get in a room and do something that starts to try to address that sort of thing.

KELLY, Q.C.:

Q. So it's important to maintain the status quo while we go get the information, that's essentially the thrust of your position, agreed?

MR. OSLER:

A. With respect to Interruptible B, yes.

Q. And with respect to other major parameters and drivers that affect that type of information?

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MR. BOWMAN:
A. I would say with a system planning.
Q. Okay. All right. Now, let me just move along here a bit. Just give me a moment. The next place I want to go to is I'd like to come back now and talk about these transmission lines. We talked about the generation assets a little bit, but let's discuss the transmission lines. Now, if the Great Northern Peninsula is assigned to Hydro Rural, then that is of benefit to the Industrial Customers because they don't bear the cost associated with having it charged to common, is that essentially correct?
MR. BOWMAN:
A. If the Great Northern Peninsula is assigned to Rural Customers, the costs that are, in the last hearing reviews, it was somewhere in the order of $1.5 million gets charged to Rural Customers, rather to all Island Interconnected Customers.
Q. Right. And in the case of Doyles and Port aux Basques transmission assets, if they're assigned to Newfoundland Power, well, that's a benefit to the Industrials because they're not

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paying a share of that, correct?
MR. BOWMAN:
A. Well, similarly, yes.
Q. Right. But each of those systems have capacity on them which ultimately feed into the entire capacity requirements of the entire system, agreed?
MR. BOWMAN:
A. No. I think that's where you're incorrect and is inconsistent with what we reviewed in the 2001 hearing. And in fact, the evidence in IC-399 indicates if it were not for the GNP interconnection, including both the GNP transmission line and the units that are out there, the LOLH would in fact be lower today on the Island Interconnected System than it is. That means that that system is not even supporting itself in terms of generation as to meet the peak loads. That means there's a net draw on the system. Overall it's degrading the system quality even though there's generation out there at the time of peak that matters.
Q. As currently configured on the system those plants help meet the LOLH criteria?

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MR. BOWMAN:
A. Well, if all that is saying that given that somebody built a transmission line to the GNP, is it further ahead with generation there or not generation there, the island is further ahead with generation there because it helps drop some portion of that GNP load at times of crunch. In the end it's not like it flows back to the system.
Q. Okay. And that's just like we talked about a few minutes ago in the curtailable B, the curtailable B helps the LOLH now, correct?
MR. BOWMAN:
A. I don't think that's what we talked about in terms of curtailable B. We're not talking about curtailable B as how it impacts the system now, we're talking about not making a short-sighted decision in the context of a need in the very near term to do long-term planning.
Q. I understand that -
MR. BOWMAN:
A. Very different than talking about a transmission line.
Q. I understand that point, Mr. Bowman. But you

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made the point as we went through the RFI which is currently on the screen that in fact it affects the LOLH even in 2004?
MR. BOWMAN:
A. I guess what I'm getting at is we're in an entirely different world here where first we talk about system planning and we're talking about long-term concerns about system planning. In this case we're talking about cost allocation, which is they're somewhat different. In terms of cost allocation where
MR. BOWMAN:
you're talking about the relative impact on customers, the question is if the GNP transmission being assigned common will raise Industrial Customer rates $1.5 million and the GNP generation assigned common will raise their rates to $200,000, do they either get $200,000 or $1.5 million of benefit as a result of that whole GNP project? And the answer is, no, they actually get no benefit. They actually get a detriment as a result of the GNP project. And now we want to go ahead and charge them $190,000 for the privilege of having a detriment to the system, or

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alternatively we're talking about the transmission, charge them 1.5 million, plus 200,000 for the privilege of having had a detriment to the system. The answer going through that is no, the GNP assets, whether it's generation or whether it's transmission are clearly Rural service assets, they're clearly part of the cost of serving Rural Customers and Industrial Customers are not to pay those under the legislation in this province.

(2:45 p.m.)

KELLY, Q.C.:

Q. Now, let's just look at NP-219 for a second. And down on the Burin--we scroll up the answer, but down on the Burin Peninsula now we already have 34.7 megawatts of capacity, correct? You can go back to the table on the screen line 15.

MR. BOWMAN:

A. I think that's a bit--that's a mishmash of NP generation down at the southern terminus and the Paradise River that is considerably farther north just off of the main grid.

Q. Yes.

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MR. BOWMAN:

A. You get to the 34.7.

Q. Yes, that's the combined total of everything. And there's a discussion also now of having 25 megawatts of wind power down there, which would in fact give 59.7 megawatts in total down there, correct?

MR. BOWMAN:

A. I don't know that that's a fair conclusion. The 34.7 is a reliable capacity number that then feeds into the types of discussions that go into an LOLH. I don't believe that anyone would say it's 25 megawatts of reliable capacity in terms of wind. You'd normally think about wind in terms of contributing to the peak and the number of megawatts you can rely on when you really need it, you'd normally think about wind as in fact zero because you can't guarantee the wind is blowing at the time you really need it. So, I think it's mixing apples and oranges to simply add the two. But the 34.7 is a reliable capacity, it's another up to 25 depending on how the wind is blowing.

Q. At 34.7 I'd suggest to you there's a

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substantial amount of generation capacity on the Burin Peninsula, would you agree with that?

MR. BOWMAN:

A. In terms of the system we're talking about here, 34.7 is almost the same size or not quite as large as the Granite Canal, yeah.

Q. So it's 34.7 is a substantial amount of capacity?

MR. BOWMAN:

A. It's not immaterial to the grid. I think that's what we saw in the LOLH type of analysis.

Q. And whatever the wind adds, it will improve that substantial capacity even further?

MR. BOWMAN:

A. It may improve it to some degree. I'm not convinced that in terms of the reliable capacity on the Burin Peninsula that the proper way to think about it would be that the wind provides zero megawatts of reliable capacity. I know that that's the way wind is thought about in other jurisdictions that I've dealt with. It may be that here for some reason someone concludes that the wind does

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have a few megawatts that you could actually lean on and rely on, given the wind condition out there, but it can't--won't reduce the 34.7, I guess, is only fair to say.

Q. No, exactly, it will be something more. Now, Mr. Osler made an interesting comment when he was talking about the transmission lines. He said, well, you know, really maybe the only one that we should have is the one that goes from Paradise River, the short segment from Paradise River to Sunnyside. And at Paradise

KELLY, Q.C.:

River there's a hydro plant, correct?

MR. BOWMAN:

A. Yes.

Q. And that hydro plant has eight megawatts?

MR. BOWMAN:

A. Yes.

Q. And so do you acknowledge that where there's a hydro plant that it should be viewed as of value?

MR. BOWMAN:

A. No. I'm just saying that that wouldn't be the reason for coming to the conclusion he was--we were discussing.

Q. Well, why single out the hydro plant, that's what Mr. Osler did? Maybe Mr. Osler could address that question.

MR. OSLER:

A. The hydro plant was close to the grid on the map that we saw earlier. And really in order to be pragmatic the point was made that given that it is close to the grid and could be viewed as contributing as much to the grid as to the Burin Peninsula which is further away than the grid is from the Paradise, if my memory serves me correctly, we wouldn't object to it being, and that particular segment of the transmission line being included as part of the common assets of the system.

Q. Well, if that's the case why wouldn't you include the line from Doyles, Port aux Basques because at Rose Blanche there's six megawatts of capacity, hydro capacity, hydroelectric.

MR. BOWMAN:

A. We haven't spent any time on the Doyles, Port aux Basques. We understood it was basically uncontested that the line is not appropriately assigned common. Hydro did that study and concluded it and we haven't seen anyone

suggest otherwise.

Q. Well, EES has raised the question that they perhaps all should be because they all have-- they all connect capacity to the system.

MR. BOWMAN:

A. Yeah. It appears that EES relies on a conclusion that Hydro made that all of this capacity is critical to meeting the system's needs. That conclusion though needs to be read in context of the study that it was included in, which failed to note that whether that capacity is in fact--recognizing it's used and useful, what are the relative benefits of it to the various customer classes. The point about Hydro is in terms of 8 megawatt at Paradise plant there is like we discussed, a plus such that the river is where the river is, the rapids are where the rapids are and you need to build a plant there and you'll build some transmission out to hook it in. Based on that, in a--looking at the system planning, it's probably reasonable to say regardless of the loads down on the Burin Peninsula, somebody would have built Paradise River and would have hooked in with a

transmission line and done it as a result of benefitting Island Interconnected System.

Q. That's true -

MR. BOWMAN:

A. The point is, but the point is that you wouldn't have run the transmission line the rest of the way down the Burin Peninsula if it weren't for the fact that there was a fairly large load of Newfoundland Power customers. That line services them, it's built to serve them, it's designed to give them the power that they need. Power doesn't flow backwards at the time of year when it matters. The peak down there is 58.7 megawatts which is well above the capacity that's installed there now, and I have that from IC-339. It's exactly analogous to the GNP transmission. It's a transmission line that's built to service a bunch of customers out in a rural area. It's not built because there happens to be a gas turbine there and we want to get that power to the grid, which is what we're saying about that stretch that goes to Paradise River. Perhaps you could choose that logic to get to the stretch of Paradise River, but it doesn't

follow for the rest of the Burin.

Q. On that logic then, though, sir, would you not agree that perhaps the line from Rose Blanche should be included, because that connects a hydroelectric project from where it is to the grid?

MR. BOWMAN:

A. Well, like I said, I haven't spent as much time looking at it because I understood it was uncontested. Hydro came to the same conclusion. It's been that way--that was the

MR. BOWMAN:

conclusion in 2001, that was their conclusion in 2003. We haven't specifically spent time reviewing that.

KELLY, Q.C.:

Q. So is the thrust of your position that only what connects a plant that is in somehow of benefit to the Industrial Customers is what should be included in your cost?

MR. BOWMAN:

A. Just so I'm sure, can you repeat the question?

Q. In other words, is it your position that only a transmission line that somehow connects a plant, and I guess I would have to say from

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what I understand your position to be that would have to be a major plant of some description, that only a transmission line that connects a major plant should be allocated any cost to the Industrial Customers?

MR. BOWMAN:

A. I think it's a--that's essentially the conclusion that only a transmission line that connects a plant that's providing benefits to the Island Industrial Customers and the Island Interconnected Customers should be paid for by the Island Industrial Customers. That's the whole principal of the Cost of Service and that's the whole principal of that's set out in the Power Control Act, is that you shouldn't pay for service to Rural Customers.

Q. Well, let's take that logic one step further. What about the line that comes from Holyrood into St. John's? There's not an electron that flows back from St. John's to Corner Brook.

MR. BOWMAN:

A. What we're talking about in terms of all of this stuff is whether there's a backbone transmission grid of 230 kV lines and there's

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a couple of radial systems that's relative small, radial systems that spin off of that, a few of which have generation at the other end. I don't think there's anybody asserting that a line that comes from Holyrood into St. John's is a radial transmission line in terms of the system that's here. It's a key part of the backbone 230 kV system and we don't debate that.

Q. And the point out of putting that example to you, though, sir, is essentially this, that surely you have to look at the system as more of an integrated whole than the small fractured components that you want to take out of it and strip off this little line because you say it doesn't serve you. You got to look at the transmission system as more of an integrated whole than you've allowed?

MR. BOWMAN:

A. I would say it's actually -

Q. I put that proposition to you.

MR. BOWMAN:

A. I would say it's actually the contrary, that in terms of looking at the assets, the purpose of the Cost of Service Study and especially

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the Cost of Service Study in this jurisdiction where Industrial Customers are not to pay the costs of serving Rural Customers is that those assets that are benefiting an Interconnected System are those that should be assigned as common, those assets that only provide benefit to other customers, and were they not in service, the other customers would be no worse off shouldn't be charged to them. So if you look at the GNP system in total, whether it's transmission or generation, the remainder of the system, whether that's Newfoundland Power or whether that's Industrial Customers would be further ahead if the GNP weren't built in terms of reliability. There's no basis to go charging them costs as a result of building a system that lowers their reliability. That normally flies in the fact of cost allocation, but in this particular jurisdiction it's also inconsistent with the way that the legislation is set out. The same logic applies to the Burin, that a transmission line that is only-- a transmission system that's basically only been built down to the boot of the Burin system to serve a bunch of customers that are

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down there, not so that it interconnects some great turbine that's out there, but to serve a bunch of customers down there is part of the cost of providing service to those customers. It's not part of the cost of providing service to the customers who are on the 30 kV backbone grid. It's the exact same logic.

Q. On the Burin line, you'll agree with me that those lines connect at Salt Pond, Lines 212 and 219?

MR. BOWMAN:

A. My understanding is that the two lines that Hydro owns don't actually connect. There's a Newfoundland Power system that connects the two. I understand that it's down at the southern, I don't know the specific geography.

KELLY, Q.C.:

Q. Well, let's put up Mr. Martin's Schedule 2 diagram and go down to the very bottom. You see there's a connection that goes down there from Linton Lake to Salt Pond which is a very short Newfoundland Power line and the two lines are effectively looped at Salt Pond?

MR. BOWMAN:

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A. That fits with my understanding, yes.
Q. All right. So, if Line 212, for example, is out for maintenance as Mr. Haynes described, Paradise River and the other units down there are still served through 219 and vice versa.
MR. BOWMAN:
A. They remain connect to the grid via 219, oh, I would say with Paradise River, it's not a question of whether 212 is down. 212 is the line that flows in both directions in Paradise River. It's only if a fault or somehow if that even happens on a segregated portion of 212 between Paradise River and what's listed here as Sunnyside, but from Paradise River being, I guess, the first square block here, it's a separate map -
Q. Yes.
MR. BOWMAN:
A. - shows Paradise River, I understand, at that location. So, if for some reason, the short portion of 212 connecting Paradise River to the grid were down, I would say it's my understanding, but we followed this up in great detail that, in theory, the Paradise River power could flow south through 212, past

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the customers down in Newfoundland Power service area and back up 219 such that some kilowatt hour may potentially make it onto the grid, if it's under light load conditions.
Q. And I'll leave that at that one. So, we have a looped system on the Burin Peninsula that provides for one line to be capable of being taken out for maintenance. Agreed?
MR. BOWMAN:
A. Not necessarily because I don't--212 has two different portions to it, only one portion is relevant to connecting Paradise River to the grid. For the purposes of what we're talking about here, we're saying 212 in total doesn't have a huge amount of cost associated with it. There's not a lot of reason to want to cut it half or a third or whatever. So, but for goodness sakes, in terms of the generation that's there, in terms of everything, even if you assign 212 the common which is not the end of the world, there's simply no basis for talking about 219, even once you talk about the looped argument. Redundancy to hooking an eight megawatt hydro plant at Paradise River is not determinative that that asset is

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beneficial to common or that is was built for that purpose. Granite Canal was built, hooked in by a single line, so obviously redundant transmission lines is not necessary.
Q. Doesn't just hook in Paradise River, it hooks in all of the generating capacity on the Burin Peninsula which totals 24.7, we just saw.
MR. BOWMAN:
A. Yeah, well, it totals 34.7, but the peak out there is 58.7. So, it's--in terms of talking about peak time of the year, it's not providing--it's the same argument as the GNP. We're not talking about a straight kilowatt hour coming off at some time of the year when it doesn't really matter. At the time of the year when it matters, should that short portion of 212 be out and should, for some reason, the rest of the system be up and running the power could flow back that way. At the time of year that it really matters, it still isn't determinative because power will still be flowing down the line, not up it. It's not contributing to the grid. It's still a net draw power off the grid, whether that surplus of line is on or off. We're back to

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the same issue as the GNP from 2001.
Q. Let's turn next and have a quick discussion of--it's 3:00, Chair, did you want to break at this stage
CHAIRMAN:
Q. I think so, yes.
KELLY, Q.C.:
Q. That will be fine.
CHAIRMAN:
Q. Mr. Kelly, do you have any idea of how much longer you might be?
KELLY, Q.C.:
Q. I'll perhaps, certainly no more than about half an hour, Chair.
CHAIRMAN:
Q. Okay. Mr. Kennedy, do you have any idea?
MR. KENNEDY:
Q. I don't think I'll be long at all, Chair.
CHAIRMAN:
Q. So, it's a possibility that we may conclude this afternoon or at least early in the morning, in any event, certainly. Okay, thanks very much, 3:15 please.
(BREAK AT 3:00 P.M.)
(RECONVENE AT 3:18 P.M.)

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CHAIRMAN:
Q. When you're ready, Mr. Kelly, please, you can continue.
KELLY, Q.C.:
Q. Thank you, Chair. Mr. Osler, Mr. Bowman, there was an RFI that I was going to take you to when we were talking about the curtailable Interruptible B. I'll just put that one up for you now, NP 179. And the answer at line six or seven was that Hydro does not require the capacity contracted for under the Interruptible B. And that ties back to the discussion we had earlier about what need to be done to determine the real value of Interruptible B. I put that up for you just to give you the opportunity to make an additional comments you wanted because I said I would.
MR. BOWMAN:
A. I'm noting the question that was asked there. It's more in regards to the incremental costs on the system.
Q. Right.
MR. BOWMAN:
A. And whether Interruptible B was somehow

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evaluated in regards, or in comparison to the Interruptible, or the incremental costs of demand on the system. And the answer appears to be no, we didn't--we're not looking at the comparison of costs versus the rate that's being paid. I don't know if that answers your question, but that's -
Q. But in order to determine that cost, we would then have to do all the analysis and studies that we've talked about earlier in our discussion, correct?
MR. OSLER:
A. I think what this confirms is they didn't do what we were talking about earlier. They simply looked at the snapshot in time and said, hey, we don't need it today and they didn't go into all the issues you and I were talking about earlier.
Q. Exactly, okay. Let's turn to a different area and this deals with the whole of load forecasting. Now, there's a issue that's raised in your testimony about the 2002 load forecast. I won't take you to the precise page, but you get into this discussion about whether there was five million allocated one

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way or the other. Do you remember that discussion?
MR. OSLER:
A. Um-hm.
Q. Yes? Okay. And I take it that arises because there were variations in both Newfoundland Power's forecast from actual and IC's forecast from actuals in 2002, correct?
MR. BOWMAN:
A. Well, in terms of looking at this, it's probably helpful to note, there was an interrogatory filed that showed the 2002 actual Cost of Service Study and we were struck and our clients were struck by the revenue cost coverage ratio in there in the indication that the measured cost to serve Industrial Customers was five million dollars lower than what they actually paid. It raises the question as to what's going on, but we're talking about a 2004 test year. So, it wasn't an exercise to go in and say, let's figure out everything about it. And let's just say, you know, in terms of big picture items, the one that was clearly a big picture item was Newfoundland Power peak came in considerably

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higher than they had forecasted. We have expressed concerns about the forecast at the last time and, I believe, the Industrial Customers had some argument on that topic. We're not trying to get into subdividing the specific impacts. We're just saying it's based on seeing that type of thing evolved from 2002. We had underlined the extent to which one would want to be careful and reflective and use some form of principled approach to looking at what Newfoundland
MR. BOWMAN:
Power's peak may be in 2004.
KELLY, Q.C.:
Q. And I accept your evidence in chief that you're not trying to do anything retroactive that you agree rate making is prospective, but if we look at the 2002 experience, can I suggest to you that there were two factors and let's just look at the numbers first. The demand for Newfoundland Power had been forecast at 1085 megawatts and came in at 956.6 for a difference of 128.4 or 13 percent in the variance. And I can take you to direct precise numbers if you want, but we'll do it

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fairly quickly. Okay. But at the same time, the Industrial Customers who had forecast 168.5, in fact, came in at only 150.3 or down 18.2 which is 10.8 percent. So, in fact, the Industrial Customers were off, low 10 percent while Newfoundland Power's, in that year, happened to be up by 13 percent. So, it wasn't just one factor, it was a combination of two factors, wasn't it?

MR. BOWMAN:

A. Well, like I said, we didn't get into the specific factors and their relative contribution, but I'll take it that what you just said, which are set out are correct and I'm not surprised, I guess, in hearing that.

Q. Now, have you looked at any kind of historical analysis of the variations in the load forecast over the last number of years?

MR. BOWMAN:

A. You say variations, in regards to variations of load forecast versus actual.

Q. The forecast from actuals.

MR. BOWMAN:

A. I've seen some information filed in regards to a number of the RFIs. I don't recall spending much time with that, except that noting to what extent Hydro seems to be optimistic versus pessimistic in terms of their long term load forecast, compared to actuals, but I haven't spent a lot of time with that, no.

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Q. Okay. And would this proposition be right, if Newfoundland Power estimates low on a consistent basis and the actual were more, then that would tend to allocated costs to the Industrial Customers or shift costs to the Industrial Customers? In other words, we had that in a test year, we came in, we were low and the actuals came in high. That would tend to then shift costs, wouldn't it, to you?

MR. BOWMAN:

A. Well, all other things being equal -

Q. Exactly.

MR. BOWMAN:

A. - Newfoundland Power's peak being lower than, being reduced for somewhat, for some factor, or being a downward adjustment in Newfoundland Power's peak, would result in a decrease in cost being assigned to Newfoundland Power and an increasing cost being assigned to Industrial Customers and rural customers.

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That's just a simple relationship that comes out of the Cost of Service.

Q. Exactly, but the corollary would also be true too, wouldn't it? If the Industrial Customers estimated low, that would have a tendency to shift costs to Newfoundland Power's customers?

MR. BOWMAN:

A. Again, I'm noting that it's a number that goes in the Cost of Service, not necessarily the customers estimate, being high or low, because that is the extent to which Hydro takes that estimate then and feeds it into the Cost of Service. And it's only at a rate setting time, 1992, 2002 and 2004 that this type of thing that we're talking about is relevant. If Industrial Customers had a lower peak inserted for the group of customers at, in a test year, all other things being equal, they would be assigned a lower proportion of the demand costs. The difference though with Industrial Customers is as time goes forward, that peak that is used for Industrial Customers is also determinative of the rates that they will pay and their availability to access power. Industrial Customers don't

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submit two separate forecasts to Hydro. They submit a power and order request to Hydro which sets out not only their forecast for the purposes of Cost of Service, it also sets out, effectively, their entitlement to guaranteed, firm supply of power -

Q. But in a test year -

MR. BOWMAN:

A. And they pay for it.

Q. In a test year, if Industrials estimate low and come in high, that will shift costs to

KELLY, Q.C.:

Newfoundland Power's customers. And so, the point that you raise well, we should look at this in terms of long term viewing. That's what's happening in the long term, correct? That's the point that you were making?

MR. BOWMAN:

A. The point, I guess the point we were making is that, if you're going to look at the forecasts that are used in the Cost of Service Study, you need to look at some form of principled pragmatic basis to say yes, these forecasts are defensible. In the case of the Industrial Customers, we have that because they're

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submitting a power and order and they're willing to pay for it. In the case of Newfoundland Power, we don't have that. That's the distinction we're putting up, is that in terms of our principle basis, Industrial Customers submit a forecast, they're going to pay for it. They have no incentive to put it higher or lower and they have real repercussions of missing their forecast.

In Newfoundland Power's case, there is a suggestion that mathematically, they would be better off setting it lower and there are no repercussions that arise from that.

Q. Let's have a look at IC 155 and just have a quick look at the historical experience. And if we go to, at page 2 of 9, we have the1994 year and if we go over to the variance column under megawatts, we have Newfoundland Power, in this particular year, ended up 14. 5 megawatts over on estimate. Whereas, if you come down through the table, you had Corner Brook Pulp and Paper over by 4.2 and if you compare it back to the actuals, you can work out the percentages, you can't just look at

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the absolute numbers. Corner Brook Pulp and Paper is over, Abitibi is over, Abitibi Consolidated in Stephenville is pretty much on, et cetera. So, in that particular year, both Newfoundland Power and Industrials were generally over.

MR. BOWMAN:

A. The mathematical relationship you describe is shown there, yeah.

Q. Okay. We go to the next one and this one, Newfoundland Power is down, but in fact, Corner Brook Pulp and Paper and Abitibi Consolidated, both Grand Falls and Stephenville are over, correct?

MR. BOWMAN:

A. Again, the math is there, yeah.

Q. Okay. Go to the next one, 1996, in this one we're up, but Corner Brook Pulp and Paper, Abitibi still up again. And we go to '97, in this one we're pretty much on target, 3.3, but Corner Brook, Abitibi, Grand Falls--Stephenville is down a bit--but Corner Brook, Grand Falls, up again. We'll go to '98, in this one, we're up, but Corner Brook is up significantly, Stephenville is up, on average,

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Industrials are up. Go to '99, we're down in this one, Corner Brook is down slightly, Grand Falls down in this one. So, this is a year everybody seems to be down. Go to 2000, Newfoundland Power is down, small change in Corner Brook Pulp and Paper, relatively neutral across that one. Go to the next one, Newfoundland Power is down, Corner Brook is up, Abitibi Consolidated is up and that's the last one; 2002, we talked about. And I suggest to you there is certainly no pattern in Newfoundland Power's forecast be it either high or low.

MR. BOWMAN:

A. I can't do statistics on that, (unintelligible) in my head, if we look through it, it seems to be that in some cases when you look at the Fall forecast that Hydro has filed here, presumably reflecting what Newfoundland Power provides them, but I don't know that for sure. There are some cases the variance is up and there are some cases the variance is down.

Q. And, in fact, if one were to try to find any pattern, one might say that, on average, the

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Industrials tend to be up more than they're down.

MR. BOWMAN:

A. Again, I can't do the statistics in my head or anything, but in this case, we're seeing Industrial Customers who are having a peak that, in some cases, is higher and in some cases are lower. I don't know what sort of systematic variation from what's forecast. I'm just going to caution that I don't know whether the Fall 2000 forecast here is the

MR. BOWMAN:

same thing as the Industrial Customers submission of power and order for that year which is the one that really matters because when they put that number in, they're going to pay for it.

The other thing, just the other thing that I note is that we're talking about a bunch of years that weren't subject to rate hearings. The point is that there is not incentive to, in either way or no impact in either way, in terms of Newfoundland Power in any regard in reference to these forecasts. It's only in the year of a rate hearing that

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it really matters.
KELLY, Q.C.:
Q. Okay. So, you haven't done any analysis on any kind of historical basis to see what the variations over the years have been? That's the bottom line.
MR. BOWMAN:
A. Well, that's correct. Our assessment isn't based on saying the Newfoundland Power is good or bad at forecasting. Our assessment is based on saying, given how sensitive cost allocation is to this issue, there should be something, principles in there and defensible in terms of the evidence that's here, that the Board can look at and say, yes, as a result of that, we think this is a reasonable peak to insert for Newfoundland Power. That's just a point.
Q. And we have no problem with the Board looking at our forecasts. Now, let me just take you to a couple of other points that kind of flow from that. Newfoundland Power's demand is a derived demand. It's a demand derived from their customers, would you agree with that proposition?

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MR. BOWMAN:
A. Newfoundland Power's demand is presumably the sum of the (unintelligible) and peak demands imposed by the customers, plus losses, plus whatever they use themselves, so that's what you mean by derived, I guess I agree with that.
Q. Okay, in other words, they're not primarily the end user in themselves, it's their customers who are the end users of the electricity?
MR. BOWMAN:
A. No, that's correct.
Q. Now, can I take you to your testimony at page 45 and you discuss here briefly the demand energy issue and I took it from all of your evidence that other than looking at what was filed in RDG No. 2, you haven't really done much more than that in terms of any kind of analysis, is that fair?
MR. BOWMAN:
A. The core of our concern was given that this information is filed and there's a number of pieces that relate to the Newfoundland Power Cost of Service and rates that are relevant to

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Industrial Customers were reviewed from that perspective, but there is some problems that a two-part rate seems to solve. We weren't specifically looking at it from is it necessarily the exact correct thing to do when, between Hydro and Newfoundland Power to have a demand energy rate, that wasn't the core of our concern.
Q. You didn't look at whether this was the most appropriate way to service customers or not and do the type of analysis that you would need to do to express a firm opinion on that, is that fair?
MR. BOWMAN:
A. That's correct.
Q. In particular, you didn't look at Newfoundland Power's rate structure to its customers, did you?
MR. BOWMAN:
A. That's correct, we did not look at Newfoundland Power's rate structure to its customers.
Q. Okay, now in lines 17 to 19 and this is on, I believe it was Mr. Browne who took you here, maybe it was Mr. Young. "To the extent that

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these Industrial rates are appropriate and track valid incremental costs on the system, a similar rate structure seems appropriate for Newfoundland Power." Now incremental costs are the type of costs that we looked at in the discussion we had earlier, aren't they? In other words, they're the long-run future costs to the system, correct?
MR. BOWMAN:
A. The word "incremental" does not necessarily imply long run. There's short-run incremental
MR. BOWMAN:
type costs and there's long run, some people get into a distinction between incremental versus marginal, but what we're just talking about here are rates tracking costs, it's as simple as that, without making it more complicated.
KELLY, Q.C.:
Q. Okay, but whether we talk about short run and long run, we're looking at the future costs, that's the point that you're making here in terms of the balancing of the impacts of costs on the system?
MR. BOWMAN:

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A. Well there are two aspects to it, one is--I just want to be clear that when we talk about a price signal, a very short-term price signal, would--may be more based on the do rates track cost and fairly allocate costs across customers, not only for the exact load forecast that's in the filing, but as variations occur outside of that load forecast. People will also talk about price signals in terms of sort of economic efficiency type arguments, that's not where the core of what we're saying here, we're just saying in terms of variations to the extent that we talk about Industrial rates having demand components and energy components, so that to the extent that their loads vary on each of those factors. Their costs vary on each of those factors. If that's appropriate, then, you know, just by simply logical extension, it would seem to be appropriate for Newfoundland Power.

(3:35 p.m.)

Q. So if we are going to talk about efficiency factors, then the type of costs that we need to look at are future costs which are marginal

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or incremental costs, correct?

MR. BOWMAN:

A. When you're talking about designing rates that are intended to target efficiency which I'd be even very cautious about at this point, you would want to look at sort of long-run marginal type costs in designing those. But as noted in, you know, when we were here in 2001, I believe Mr. Brockman brought this up at that time efficiency is one of a number of factors that people balance off in terms of designing rates or in terms of doing cost of service. In this case, this jurisdiction has a certain framework that's based on embedded costs and average cost pricing within the embedded Cost of Service Study. It's not based on a marginal cost type of rate setting or something that's more reflective of marginal costs, or marginal pricing or something like that.

MR. OSLER:

A. But to be, just to be helpful, when we're looking at demand costs and capacity costs, typically you're looking at embedded historic cost or you're looking at the cost in the

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future to build some more. You're typically not looking at a cost that increases up and down as you turn on and off the switch, because it's literally the capacity cost of the system.

Q. Right.

MR. OSLER:

A. So you're either dealing with embedded or you're dealing with the future, you're certainly not dealing with something like oil that gets burned or not gets burned as you turn off and on the switch.

Q. Exactly correct, and in fact, if I just follow that discussion with you, Mr. Osler, please, the past costs are obviously ones that are in the past. If what you're trying to determine is, well what is the appropriate cost for spending on DSM versus spending on new capacity, what we need to know is that incremental cost in the future, correct?

MR. OSLER:

A. Correct.

Q. Right, and that, if we're going to target efficiency, that's the item that we've got to know. Now, would you agree that DSM is to be

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evaluated on a marginal cost basis?

MR. OSLER:

A. DSM should be looked at, I mean, I'm nervous just with using these terms, they can mean all sorts of different things to different people. DSM is typically and properly evaluated looking at the effects it has on the future cost to the system.

Q. Okay, all right. Now, Mr. Greneman, I can take you to this passage, if you like, perhaps that's a good thing to do. If we go to his

KELLY, Q.C.:

report and it's at page 10--sorry, it's in RDG No. 2, Mr. O'Reilly, my apologies. There we go, at page 10. Could you just scroll back up to the top there? There we go, it's the third line down, Mr. Osler. "Typically the largest load management opportunities are derived from commercial and industrial facilities, rather than residential facilities and in several US jurisdictions, demand rates have resulted in significant load shapes shifted when targeted at large users." Now, we talked about the Interruptible B rate. From your experience, what other type of load management

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opportunities exist at the commercial and industrial level?

MR. OSLER:

A. Well, I haven't come with my mind focused on that, so I may well miss all sorts of things, but as distinct from interruptible type of rate structure and load management types of approaches, there are also the efficiencies that come from programs designed to reduce lighting or to make lighting more efficient, to make motors more efficient, to have processes more efficiently using electricity, so that utilities frequently spend a lot of time and money with some of their largest customers to mutually assist each other in coming to things that save the customer costs and save the system costs; therefore, all the other customer's costs. And the shopping list can be relatively long. I sat in on a meeting recently in Manitoba where the vice-president in charge of this type of thing was describing how they have evolved over a decade and how much more of it is cooperative today than it was ten years ago, and how very often, because of the way in which people have evolved, what

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isn't sending as much money is just collaborating and coming up with expertise and exchange of information so that people in fact end up saving money. But the cost savings for the customer are big enough that they're not even looking to the utility to help fund a portion, they're just happy they got a basis for arguing it internally with management and getting it done. Because the problem is, historically there are costs to be saved, people can make that analysis, but there are many, many of these commercial and even industrial operations without commenting on the ones here. It doesn't intuitively hit management that these are the big cost savers that are going to make people's careers or make a big difference, so the learning curve is important.

Q. Let me ask you a couple of questions derived out of that then, if we are concerned about capacity on the system, have you, as an advisor to the Industrial Customers, advised them about opportunities for such programs?

MR. OSLER:

A. The advise that I've had has been very focused

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on rate hearings.

Q. Would the answer be because you haven't been asked?

MR. OSLER:

A. It could be, but I don't think it would come up in the context of getting ready for a Hydro rate hearing where the issue of demand side management programs isn't even on the table.

Q. Do you know whether Hydro in fact has had any of those type of discussions with the Industrial Customers?

MR. OSLER:

A. I don't know one way or the other.

Q. Okay, would it be fair to assume since one of the load management mechanisms is curtailable B, that since Hydro is proposing to discontinue that, that those type of discussions, especially if it involves expenditure of funds have not taken place, would that be a reasonable conclusion to draw?

MR. OSLER:

A. I'd be, of the abundance of caution, would resist drawing conclusions.

MR. BOWMAN:

A. The one thing I would just note that we have

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reviewed our RFIs in this filing which suggest that the DSM activities, as Hydro classifies them, at this time go basically, exclusively to their HYDROWISE Program.

Q. That was going to be my next question, Mr. Bowman, you're anticipating, thank you very much. So from that answer, would it be fair to say that Hydro has not looked at spending money on those type of programs with Industrial Customers?

MR. BOWMAN:

A. I was being careful of saying that's the way that, in terms of when Hydro is asked what DSM activities it's undertaken, the responses that I've seen say, relate to HYDROWISE. I'm not sure whether a lot of these other things with Industrial Customers, in their mind intuitively go to DSM. They may go to other topics, I can't honestly say.

KELLY, Q.C.:

Q. Whether we can it DSM or load management, may I suggest to you that there is no difference as to how the cost of those should be evaluated, i.e. they should be evaluated on a

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marginal cost principle, whether that's the Industrial Customers or any other residential, for example, DSM program. Would you agree with that?

MR. OSLER:

A. Yes, I mean, load management in the way I would use the words is part of the broad demand side management approach. I know some don't think of it that way, but--and they should be evaluated using similar perspectives.

Q. Okay, let me just ask you one last series of questions. If we go to your report at page 45, under the "Revenue Stability" section there, there is a reference at lines 21 through 23 about volatility will be introduced into Hydro's revenues. The first question is have you looked at the extent of volatility in Hydro's revenues? Have you done any analysis of that?

MR. BOWMAN:

A. In terms of the point that's listed here, again, I would note that these are listing a number of items that are raised in Exhibit RDG 2 and just simply comment on them. They are

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not things that we are flagging or things that we spent a lot of time analyzing.

Q. And that's my question, have you, as the Industrial Customer's expert, have you looked at the volatility on Hydro's revenues?

MR. BOWMAN:

A. We've not looked at the volatility on Hydro's revenues of introducing a demand energy rate of whatever four might be proposed for that.

Q. Have you looked at the volatility on Newfoundland Power's revenues?

MR. BOWMAN:

A. No.

Q. Have you looked at the impact on customer rate stability?

MR. BOWMAN:

A. In regards to the rates that Newfoundland Power would charge? No. In regards to the rates that Hydro would charge, our only concern--our only comment that I believe may be highlighted in other sections of this, relate to the rate stabilization plan, but things have now been basically addressed, from our opinion.

Q. My question goes to the first of the points in

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terms of rate stability to Newfoundland Power's customers, have you done any analysis of the impact on Newfoundland Power's customers?

MR. BOWMAN:

A. No.

Q. And for that matter, to the extent that Newfoundland Hydro's rates track Newfoundland Power's, have you looked at the impact of customers of Newfoundland Hydro?

MR. BOWMAN:

A. In terms of Rural customers, no.

Q. Thank you, gentlemen, those are all of my questions.

CHAIRMAN:

Q. Thank you, Mr. Kelly. Good afternoon, Mr. Kennedy, when you're ready please.

MR. KENNEDY:

Q. Chair, actually I'm going to be briefer than I imagined, the issues have been thoroughly canvassed by the other counsel. I have no questions to ask.

CHAIRMAN:

Q. None?

MR. KENNEDY:

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A. None.

CHAIRMAN:

Q. Okay, thank you very much. Any re-direct Mr. Hutchings please?

HUTCHINGS Q.C.:

Q. Just one matter I wanted to touch on, Mr. Chair. Mr. Bowman, in your discussion with Mr. Kelly about the impacts of Newfoundland Power's forecasts not turning out to be accurate with respect to a test year, you had some discussions about shifting of costs and I

HUTCHINGS, Q.C.:

think the discussion went along the line that if the Industrial Customers had underestimated their actual peak, there would be an effect to shift costs to Newfoundland Power. Did I understand that correctly, in the test year?

MR. BOWMAN:

A. I was dealing very simply with the mathematical relationship that if one took a cost of service study, kept everything else equal and took the peak load that was indicated there for Industrial Customers and reduced it, it would have the effect of reducing the cost assigned to Industrial

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Customers and increasing the cost assigned to Newfoundland Power. It was just that simple of a mathematical relationship.

Q. Yes, okay, and that was a test year effect which would have an impact on the rate that would be derived out of the cost of service study in that test year?

MR. BOWMAN:

A. Yes, it's only a test year effect.

Q. Okay. In terms of the actual dollars that Industrial Customers would pay out, would there be any saving to Industrial customers by underestimating their actual loads for the purpose of the forecast?

MR. BOWMAN:

A. We spent some time in the evidence going through the particular Industrial Customer rate form, as it's talked about in here, and there's a number of different components of service to Industrial Customers under which they're billed. There's the base component, which is defined by the power on order as the maximum number of megawatts under which they can receive firm energy and firm supply for a certain number of megawatts of power. If they

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go above that, to the extent that it's available, with no guarantees, they move into an area of non-firm power, which is at a much higher incremental rate, but as long as it's on a very low load factor type of load, like the odd excursion to meet a very short-term peak, it's a more efficient use of their power and the rate set up than taking the power on order higher. So there's a balancing in there from the perspective of Industrial Customers setting the power on order high enough that it gets them: a. all the power they need at firm rates and that's guaranteed supply, and that they're willing to pay for because they paid for the power on order regardless of what their peak is. But low enough that it's not designed to catch these very small load excursion which are more properly served under a non-firm, non-guaranteed power at very low load factors. Within that balancing, they'll submit to Hydro a power on order request. My understanding is that power on order request is what, in all cases, eventually feeds into the cost of service study. So there's not an incentive to set it too low or set it too high

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or else they run across problems on that power on order and their access to power at a reasonable rate or at all.

MR. OSLER:

A. Just make one point. The peak, if you have a non-firm power demand, which is what he's just talking about, it does not contribute to the peak. It does not contribute to the cost of service allocation, just keep that in mind. So by definition, an excursion beyond what you're entitled to is not an excursion that should be counted when doing a test year assessment of firm order, for capacity purposes.

Q. On the Industrial Customers' side, if the amount of power, amount of capacity, megawatts used, exceeds that in the forecast, the Industrial Customers pay for that excess demand, correct?

MR. BOWMAN:

A. It might help if we use--sort of set out some simple numbers for it, but an individual Industrial Customer sets out a power on order of say 50 megawatts and then on their actual usage, they make it up to 55 megawatts, that

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extra five megawatts is not a peak demand imposed on the system because its interruptible power and can be shut off at any time. But they do pay for that currently under the non-firm demand rate. Under their proposal in the revised Banfield evidence, they'd be paying for it as a premium energy rate, not tied to demand but tied to the number of kilowatt hours taken there. Either way, all that power taken above 50 megawatts is non-firm, high incremental cost, complete

MR. BOWMAN:

flow-through 100 percent cost recovery to Hydro power, that they're not guaranteed and that is not relevant to the cost of service study. I don't know if that answers your question.

Q. I think that addresses the point. Okay. That's all I had, Mr. Chair.

CHAIRMAN:

Q. Thank you, Mr. Hutchings. We'll move now to Board questions. Commissioner Saunders.

COMMISSIONER SAUNDERS:

Q. Just a couple, Mr. Chair. On the Interruptible B contract, and there's been a

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considerable amount of evidence and discussion and to some extent, it's confusing to me at least. As I understand it, the Interruptible B contract that existed between Hydro and Abitibi Stephenville is no more. Is that your understanding? I guess, Mr. Kelly, you made reference, towards the end of your cross-examination to it and you spoke of it as being still in existence.

KELLY, Q.C.:

Q. In my understanding, and Hydro can speak to it, is that it has expired. I took it to -

COMMISSIONER SAUNDERS:

Q. Yes, it has expired. Is that--Mr. Young, yes?

MR. YOUNG:

Q. That's common ground.

COMMISSIONER SAUNDERS:

Q. And that's your understanding as well, Mr. Hutchings?

HUTCHINGS Q.C.:

Q. That's common ground, yes.

COMMISSIONER SAUNDERS:

Q. Yes. There's two elements of that question, I guess, in my mind. One is what is that the Industrial Customers are asking the Board to

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do in relation to that contract or to that DSM possibility, if you like? And under what section of the Act are you asking us to act here? You know, Hydro has not made any application to have that revived in any way. There's nothing in Hydro's application about the Interruptible B contract per se. So I'm wondering, Mr. Hutchings, what it is you're going to be arguing at the end in terms of what it is you want the Board to do?

HUTCHINGS Q.C.:

Q. What we want the Board to do, Mr. Commissioner, is to direct Hydro to include as a rate available to Industrial Customers an Interruptible B type of scheme, and that will be, in our view, this is--while it was done by way of contract before, it is, in fact, nothing more than a rate and that is how it exists in other jurisdictions. So that in addition to the firm rate for Industrial Customers and the non-firm rate for Industrial Customers and the RSP which applies to Industrial Customers, there'll be a fourth page which will describe a rate called the--call it Interruptible B, call it curtailable

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power, whatever, but in the circumstances that it is a just and reasonable and appropriate rate to be offered to Industrial Customers by Newfoundland and Labrador Hydro. The Board obviously has a general rate application before it, and you have the power to determine what forms of rates there shall be. In the same way as you can adjust how the rate stabilization plan works, you can add additional types of rates that the Board feels is just and reasonable in the circumstances.

COMMISSIONER SAUNDERS:

Q. Are you familiar, Mr. Hutchings, with how the Interruptible B contract got in place in the beginning? Was it an agreement between Hydro and Abitibi Stephenville and to what extent was the Board involved in that?

HUTCHINGS Q.C.:

Q. That was in 1993, at a time when the regulatory regime for Newfoundland Hydro was quite different than it is now. To my knowledge, I don't think the Board was involved in the approval of the contract in any way. As I understand the history, Newfoundland Hydro approached all of the

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Industrial Customers with this possibility and a number of them considered it and the only one that actually took it up at the time was Abitibi Stephenville and the terms of the contract were then negotiated. Mr. Young might want to speak to that.

MR. YOUNG:

Q. Yes, I can confirm that. That's a fairly accurate depiction as to how it occurred, and just further on that, Commissioner Saunders, the point Mr. Hutchings raised as to the

MR. YOUNG:

jurisdiction of the Board relating to Hydro and Industrial Customers was different back then. These were essentially non-regulated issues, although there were certain cost of service implications that made the Industrial Customers interested in the process. The contract carried on within the Board's jurisdiction under a provision of the legislation, which said that essentially that the rates that were in place carried on until they're changed by the Board, and we didn't ask for a variation of it, and we just let the contract expire when it did. So now

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essentially, it's in with a blank page and we didn't ask the Board in this application for a renewal of that.

COMMISSIONER SAUNDERS:

Q. If you had intended to renew it, would you have come forward in your application to ask the Board to approve it?

MR. YOUNG:

Q. Yes, I think Mr. Hutchings' characterization of the way it would work going forward is essentially accurate. If we had thought it was appropriate for the Board to approve an Interruptible B sort of arrangement of whatever sort we thought it might be, we would have applied with a rate sheet indicating what the terms and conditions of that rate would be. It probably wouldn't be in the form of a contract, but it would be more like--I'm speculating to some degree. It would be more like the other rate forms that we have, but as I mentioned a second ago, and I think it is common ground, we haven't applied that way.

COMMISSIONER SAUNDERS:

Q. Okay. Just one other question and that was in relation to a question Mr. Browne asked and

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you got into a discussion on gaming the system in reference to Newfoundland Power's generation, and God forbid if they do, but who would benefit from their gaming of the system, Mr. Osler?

MR. OSLER:

A. Generally only the party who's doing the gaming would benefit. That's the idea. That's why the word is used that word, so that Newfoundland Power, in that example, would benefit by doing something that was to the disbenefit of everybody else on the system. And it's not made in a pejorative sense in the sense that Newfoundland Power is some evil person who would do this. It's shouldn't design something that invites somebody to do that.

Q. But if there was any gaming of the system, who would be the ultimate beneficiary of it?

MR. OSLER:

A. Well, in the example given, it would be Newfoundland Power because -

Q. Beyond that?

MR. OSLER:

A. Well, beyond that, that would depend on how

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the benefits of gaming were flowed through to the customers of Newfoundland Power or its shareholders.

Q. And to the detriment of?

MR. OSLER:

A. To the detriment of the people and the other customers or shareholder of Hydro, which would include the Industrial Customers as a major element, in terms of customer, given the nature of the system.

Q. As I understand it, and I'm not sure I'm correct in all cases with respect to Newfoundland Power's generation, but maybe you're familiar, Mr. Osler or Mr. Bowman, isn't their generation in large part subject to Hydro's dispatch?

MR. OSLER:

A. I'm not certain of that. I read parts of it that made me think that was the case. Other parts of it, certainly all this comment in the evidence of Hydro and Newfoundland Power about the prospects of somebody gaming the system, lead me to believe that both parties seem to agree that they don't have that type of control of the switch back at Hydro. At other

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times I read it and I thought they perhaps did, sort of wondered why they wouldn't, type of thing. So since both parties have talked extensively about the risk, I assume that I should be advised that Hydro ultimately doesn't control the switch with respect to the generators of Newfoundland Power.

Q. Well, we may hear something more on that later on. Thank you, Mr. Chair.

CHAIRMAN:

Q. Thank you, Commissioner Saunders. Commissioner Whalen?

COMMISSIONER WHALEN:

Q. I have no questions. Thank you, Chair.

CHAIRMAN:

Q. I have no questions. Thank you, Mr. Bowman and Mr. Osler. We're 15 minutes, I guess, ahead of schedule, which is a good thing, as Martha Stewart says. We'll reconvene at 9:00 tomorrow morning and we'll be hearing from Hydro's cost of service expert, Mr. Greneman. Look forward to that. Thank you.

(CONCLUSION - 4:00 P.M.)

CERTIFICATE

I, Judy Moss Lauzon, do hereby certify that the foregoing is a true and correct transcript in the matter of Newfoundland and Labrador Hydro's 2003 General Rate Application for approval of, among other things, its rates commencing January, 2004 heard on the 13th day of November, A.D., 2003 before the Board of Commissioners of Public Utilities, Prince Charles Building, St. John's, Newfoundland and Labrador and was transcribed by me to the best of my ability by means of a sound apparatus.

Dated at St. John's, Newfoundland and Labrador this 13th day of November, A.D., 2003

Judy Moss Lauzon