New Brunswick Board of Commissioners of Public Utilities

In the Matter of an application by the NBP Distribution & Customer Service Corporation (DISCO) for changes to its Charges, Rates and Tolls

Delta Hotel, Saint John, N.B.
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....

CHAIRMAN: Good morning. When everybody is settled in, I have got my homework here. And that is to enter as exhibits the various Intervenor evidence.

And the evidence of the Canadian Manufacturers and Exporters, New Brunswick Division is CME-2. And Vibrant Communities Saint John evidence is VCSJ-2. And the Public Intervenors is PI-3.

MR. MACNUTT: Just a clarification, Mr. Chairman. This is the responses of the particular participant that you are mentioning and the responses submitted by them to IRs submitted to them by various Intervenors in respect of the evidence of each --

CHAIRMAN: Mr. MacNutt, you are absolutely right. These are the responses in the Interrogatories. I misread that first letter and went from there.

So CME-2 are the responses to the interrogatories by Canadian Manufacturers. VCSJ-2 is likewise the responses of the Vibrant Communities Saint John to their evidence. PI-3 is responses of their witness to the Interrogatories. And UM-2 are their responses. EGNB-2 likewise. Would the band leader please identify the group.

RCC-2 is of course the Rogers Cable responses. And PUB-2 are the Board staff's witnesses' responses to the interrogatories.

MS LEGERE: Volume 1 of 2 and volume 2 of 2.

CHAIRMAN: Sorry. And the PUB-3 are the second volume of those responses. That should do it, Madam Secretary?

MRS. LEGERE: Thank you.

CHAIRMAN: Now we will have the appearances. I just wanted to clear up one thing yesterday. I talked -- I perhaps misspoke myself when I talked about Energy Probe, Research

Foundation and New Brunswick System Operator.

My intention was to say I would not bother calling for them anymore. The onus is on them that if they do come to the hearing that they identify themselves in that they have not been here until this time.

As I result of what I said yesterday, why Mr. Roherty of the New Brunswick System Operator communicated with Board staff and said they wished to be moved to Informal Intervenor status. So we will effect that on the records. And Energy Probe, I just won't bother calling for them until they do show up. Because they may show up in the rate portion of this hearing. I don't know.

So having said all of that, for the applicant today?

MR. MORRISON: Terry Morrison, David Hashey, Lori Clark and of course our witness panel, Mr. Chairman.

CHAIRMAN: Thank you. Canadian Manufacturers and Exporters?

MR. BOOKER: Mr. Chair, Andrew Booker from the Irving Group and Pat Burke from Flakeboard are also here as CME members.

CHAIRMAN: Okay. Which hat are you wearing?

MR. BOOKER: Officially the Irving hat.

CHAIRMAN: CME, Mr. Plante? Not here today.

MR. BOOKER: Mr. Plante isn't here. But there are CME members in the audience.

CHAIRMAN: Okay. That is great. And somebody has opened the door. So that is fine. Conservation Council?

MR. COON: David Coon, Mr. Chairman, for the Conservation Council.

CHAIRMAN: Thanks, Mr. Coon. Eastern Wind? Not here. Enbridge Gas New Brunswick?

MR. MACDOUGALL: David MacDougall, Mr. Chair. And I'm joined by Ruth York and Dr. Alan Rosenberg.

CHAIRMAN: Thank you, Mr. MacDougall. And the Irving Group have already logged on. Jolly Farmer and Rogers Cable? And self-represented individuals? The Municipal Utilities?

MR. GORMAN: Good morning, Mr. Chairman, members of the Board. Raymond Gorman appearing as counsel for the Municipal Utilities.

Today I have Charles Martin and Pierre Roy from Edmundston Energy, Dana Young and Jeff Garrett from Saint John Energy and Paula Zarnett, Consultant.

CHAIRMAN: Thank you, Mr. Gorman. Vibrant Communities? I believe Mr. Peacock came in later on yesterday, yes. Okay. And the Public Intervenor?

MR. HYSLOP: Good morning, Mr. Chairman. Peter Hyslop, Mr. Barnett and Ms. Young and Ms. Power.

CHAIRMAN: Thanks, Mr. Hyslop. Any Informal Intervenors that want to go on the record?

MR. BURKE: Pat Burke from Flakeboard, Mr. Chair.

CHAIRMAN: Right. Mr. Burke. And Mr. MacNutt, who do you have with you today?

MR. MACNUTT: I have with me, Mr. Chairman, Doug Goss, Senior Adviser, John Lawton, Adviser, Arthur Adelberg, Consultant, Steve Garwood, Consultant and John Lawton -- or excuse me, John Murphy, Consultant.

CHAIRMAN: Thanks, Mr. MacNutt. Okay. Does the applicant have any preliminary matters?

MR. MORRISON: Yes, Mr. Chairman, a couple of things arising from yesterday. In Mr. MacDougall's cross he raised the 2001 Energy Planning Survey which was supplied to him. And I misspoke, Mr. Chairman. I think I indicated that that didn't form part of the public record.

I was mistaken in that. It is part of the public record. It is in exhibit A-16, Disco EGNB IR 25. And it was supplied to everyone. The electronic version was only supplied to those who signed a restricted use agreement. So I just wanted to clarify that so that no one got the impression that Mr. MacDougall got something that others did not.

Also, Mr. Chairman, in going through the transcript we have identified what appears to be a typographical error which occurs at page 863.

And it's at the top of the page beginning at line 2, Mr. Marois' response was, as it reads in the transcript, "I almost venture to say that it probably encourages the least." And I think he said "It probably encourages waste." So I just want to make that clarification.

CHAIRMAN: Okay.

MR. MORRISON: And there is one other matter. There seems -- and I will have Mr. Larlee address this. In his cross examination Mr. MacDougall put questions to the witnesses with respect to energy losses. And you recall the 35 percent minus the 7.8 percent. I believe what was said yesterday was incorrect.

And Mr. Larlee, we can do it now or in redirect. But it seems to me that if there is anything arises from it -- and I don't think it is material. But Mr. MacDougall may want to address it now.

CHAIRMAN: On the second -- or the last page of that Interrogatory was the correct number. And they were quoting 3.3 or something from --

MR. MORRISON: It is not a question of whether the right number is quoted, Mr. Chairman. It is a question of whether it is cumulative. In other words do you take the 35 percent --

CHAIRMAN: Let Mr. Larlee address it.

MR. MORRISON: Okay.

CHAIRMAN: Go ahead, Mr. Larlee.

MR. LARLEE: The question was really was it cumulative. It is cumulative. But I think I left the wrong impression in that it is cumulative. But you start with the 35 percent. And the easiest way to explain it is imagine if you put 100 units of fuel into your plant. You are only going to get 35 units equivalent energy out. Now you have those 35 units. The losses apply to those.

So you have 7.8 percent losses in total effectively of 35, not of 100. So then rather than having a number in the order of 28 percent, I think what Mr. MacDougall was saying, it is 32 percent.

MR. MORRISON: Those are all of the preliminary matters, Mr. Chairman.

CHAIRMAN: Good. Thank you. Mr. MacDougall -- well, number 1, do we go back to Mr. Coon to begin with?

MR. MACDOUGALL: That is my understanding, Mr. Chair.

CHAIRMAN: Okay. Great. Mr. Coon, do you want to move up? Thank you, sir.

<u>CROSS EXAMINATION BY MR. COON</u>:

Q.288 - Good morning. Mr. Larlee, I have just a couple questions for you, really. That's all. If we could look in exhibit A-3 in Mr. Larlee's direct evidence. On page 4 there is a table, of Mr. Larlee's direct evidence. And as I understand this, Mr. Larlee, you have broken out your customer class into nine distinct classes of customers for the cost allocation study. Is that correct?

MR. LARLEE: Just doing a quick count here. I count eight. One, two, three, four, five, six, seven, eight. The reason why I am counting eight is because really what we have done with residential is segmented a single class. We don't have as a rate class electric heat customers and non-electric heat customers. So if you count all of the others you end up with eight distinctive rate classes.

Q.289 - Okay. So you are just -- with respect to residential customers you mean this is essentially single rate class and you are -- well you tell me why you have broken that out.

MR. LARLEE: I think I mentioned it yesterday in my overview is that the -- through the New Brunswick Energy Policy, there is a lot of emphasis on electric heat and non-electric heat. And I thought that it would add some value to the cost allocation study if we could segment that class into those two categories so that we could provide some direction to rate design ultimately. And I had available to me load research data, which I though would enable me to do that. So that is why I did it.

Q.290 - That's great. Thanks. So I will refer to nine categories then so we will understand each other, not nine classes. So when I say nine categories, that includes the breakout of the residential class into the two sub-categories. Is that right? Because I have got a couple questions on --

MR. LARLEE: Well I don't like the word "category" either.

Q.291 - All right. What would you like me to call it?

MR. LARLEE: I will explain why I don't like the word "categories" because in the rate schedules and policies manual we use the word "category" as well. And again, there is no category in the rate schedules and policies manual related to electric heat and non-electric heat. So really there is eight rate classes and the residential class is segmented.

Q.292 - All right. Well I will struggle along with how to label this then as we go forward. My question specifically is do the -- going through this and I couldn't really see this -- did the power purchase agreements have the effect of differentially allocating the costs of specific generating facilities to the different sections -- different rate classes here?

MR. LARLEE: No. Within the revenue to cost ratios that you see there are included the supply costs that Disco has to pay to serve these customers. And those supply costs are driven by the power purchase agreements.

Q.293 - So the costs associated with Lepreau or with the hydro electric facilities are not differentially assigned to different customer classes in allocating costs?

MR. LARLEE: No. If you are saying did we look at each individual generating facility and assign it directly to a class? No. And I think if you look at the cost allocation study in schedule 5.1, you will see quite clearly how the allocation and supply cost was done.

Q.294 - Thank you. So then you didn't break it out into categories either? I am thinking of you know, some customer classes require largely base load power like the industrial transmission customers. So do the base load plants get -- the cost of the base load generating capacity get allocated accordingly?

MR. LARLEE: The way the cost allocation is done is the costs are first -- the supply costs, the generation supply costs are first classified as either demand related and energy related. Then those two separate classifications are then allocated to the classes. The demand related portion is allocated based on the coincident peak of each class and the energy portion is allocated based on the energy requirement for that class, including losses.

Q.295 - So help me here. Does that have the effect in doing that of ensuring that customer classes who largely require base load power are largely having costs of base load powers allocated to them in their rates?

MR. LARLEE: Well in the process of classification, you are taking the demand component and you are allocating that based on the coincident peak demand. So as a result, all those demand costs go to the classes with higher costs going to the classes that contribute most of the peak and less cost going to classes that don't contribute to the peak.

So in that way there is an allocation of costs based on the -- essentially the load shape of each class.

Q.296 - So as I understand it then, it well reflects the peak -- the allocation occurs more according to peak demand and therefore those customers classes who largely require base load power and don't have much peaking in their profile, the costs aren't properly allocated to them associated with the types of power they require?

MR. LARLEE: No, I disagree with that. I was referring to the demand costs. Now if you look at the other side, you have your very -- very flat customers with the very high load factor -- in other words, they have very a low peak relative to their energy consumption -- they are going to be allocated a large portion of the energy costs.

So the overall supply costs are allocated appropriately depending on the load shape of each customer class.

Q.297 - Okay. Thank you, Mr. Larlee, for that. If we can just then switch in your appendix 1 to your direct evidence on page 20. There is a table or schedule, I guess. Page 20, that would be schedule 5.1. So that is in the appendix, schedule 5.1 on page 20. That would be entitled Supply Cost CLassification Allocation Power Purchase Agreements Fiscal Year 2005/6 budget.

MR. DUMONT: Excuse me. Schedule 1.4, you said?

MR. COON: 5.1. 5.1, on page 20.

Q.298 - Mr. Larlee, could you just briefly describe what this schedule is intended to demonstrate?

MR. LARLEE: What this schedule is showing is it is showing the allocation of all Disco's supply costs to the classes and the sub-classes. At the bottom of the schedule in lines 19 to 29 are the details of the classification. Essentially the schedule is upside down and what is happening first off are -- is going on in lines 19 to 29 so we are doing the classification there of the PPA costs. And then the upper part of the schedule is actually the allocation of those costs to the classes.

Q.299 - Thank you. Can you explain then, I am looking at the lines 19 to 29, on line 20 why is it that the irradiated fuel management costs are broken out from the other Nuclearco costs for this purpose?

MR. LARLEE: I would like to apologize. My title for line 20 wasn't very clear. Really that should read "Nuclearco fuel and irradiated fuel management".

So what I have done here is I have taken the -- essentially the variable costs related to all of the Nuclearco supply and broken it out. And you can see by looking at those two numbers that there is a significant difference between the two. So out of the total Nuclearco PPA cost, the actual fuel and variable costs are in the order of 5 percent. So the large vast majority of that PPA cost is fixed cost.

Q.300 - And just to clarify, the irradiated fuel management portion of this, why would that not be considered a fixed cost?

MR. LARLEE: Well it is related directly to the amount of fuel that goes through the units and it is the short-term management of the fuel. The more fuel that is consumed the more fuel management costs react. So it varies in proportion to the amount of fuel that goes through the unit.

Q.301 - Then how do the long-term fuel management costs get allocated in here?

MR. LARLEE: I don't know. I don't have that information. The information that I used to make this split is provided to Disco as part of managing the fuel costs -- as part of auditing the fuel costs that come to Disco so we only have privy to the actual fuel portion. And I am not privy to Nuclearco's other costs.

Q.302 - Okay. In the power purchase agreement with Genco, there is a section dealing with environmental costs which would be a new -- include new costs that we haven't seen before around things like buying carbon permits under the new Federal regime -- regulatory regime for capping greenhouse gas emissions.

Where would such environmental costs appear here? Would they be broken out separately from Genco's demand in energy costs or would they be simply patched through, enfolded into Genco's energy costs for purposes of allocation?

MR. LARLEE: The Genco costs that you see here are the costs that were budgeted to be billed to Disco in 05/06. Any costs that would come through the PPAs in future years, we have to deal with them as we get them. I am not familiar enough with the PPAs myself in order to discuss if there are specific clauses for special charges at this point in time.

MR. COON: Thank you, Mr. Larlee. And that is all I have this morning, Mr. Chairman.

CHAIRMAN: Thank you, Mr. Coon.

MR. MORRISON: Mr. Chairman, I should have brought this up earlier. But we keep referring to the 1992 PUB decision, CARD decision. Everybody has been referring to it. All of the experts seem to refer to it.

And it has never been marked as an exhibit. I don't know whether it ought to be or not or whether we can just continue to refer to it. I do have a copy here to be marked if that is the Board's wish, so --

CHAIRMAN: I don't think so, Mr. Morrison. I think that our previous decisions are a matter of public record.

MR. MORRISON: That is fine, sir.

CHAIRMAN: And Mr. MacDougall, are you coming forth with your trolley again?

MR. MACDOUGALL: I am, Mr. Chair.

CHAIRMAN: Good.

CROSS EXAMINATION BY MR. MACDOUGALL:

MR. MACDOUGALL: Good morning, Mr. Chair and panel members. Good morning, gentlemen.

Mr. Chair, it may be useful for a significant portion of this cross examination to have at hand the NARUC Electric Utility Cost Allocation Manual. And that is found at exhibit A-14, appendix 7. And exhibit A-14 is volume 2 of 3 of the first round appendices.

CHAIRMAN: A-14, appendix --

MR. MACDOUGALL: 7, Mr. Chair.

CHAIRMAN: Thank you.

MR. MACDOUGALL: And I will be referring to other volumes throughout this. But it may be useful if you keep that one at hand. Because I will be back and forth to that from time to time.

Q.303 - Now Mr. Chair, just to start with I would like to just read an excerpt. And Mr. Ketchum quotes from the NARUC manual in response to one of the IRs. The IR he is responding to -- and I don't think we have to pull it up, so that we don't have too many binders. But just for the record it is PI, second round, IR-50(c).

And in his response Mr. Ketchum quotes from the manual where it states the following. "Equivalent peaker methods are based on generation expansion planning practices which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added."

Mr. Ketchum, I would just like you to confirm that that is your understanding of the comment on the equivalent peaker method from the NARUC manual?

MR. KETCHUM: Thank you, Mr. MacDougall. Could you give me the rest of the references in the manual so I can just --

Q.304 - I unfortunately don't have that, Mr. Ketchum. So you would have to look to A-16, PI, second round, IR-50(c).

MR. KETCHUM: Just a moment please.

Q.305 - I believe that reference says it is on page 52 of the manual. And at the end of PI-50(c) the quote you gave was "Equivalent peaker methods are based on generation expansion planning practices which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added." Correct?

MR. KETCHUM: Yes. I have that reference now. That is correct.

Q.306 - Thank you. Now if we could turn to your evidence. And that is in A-3. And I believe Mr. Ketchum's evidence is the last tab in A-3.

Mr. Ketchum, I just want to ask a few questions that comes back to some points you made yesterday in talking about references made by other parties to NB Power's use of the peaker credit method.

And on page 5 at line 11 you state "Ultimately based on the characteristics of the NB Power system, the peaker credit method was selected as most appropriate."
And then you go on to state that "This method of cost classification of fixed production costs reflects the tradeoff of capital for energy cost savings inherent in the mix of generating facilities. The mix employed is designed to minimize the total cost of providing energy to the grid." Correct?

MR. KETCHUM: That is accurate. Yes, sir.

Q.307 - And this was -- from your discussion yesterday I understand that you are referring back -- when you say "Ultimately based on the characteristics of the NB Power system, the peaker credit method was selected", this is referring back to the report that you gave, the Reed Report that used that to support the 40/60 split after the Board had asked for NB Power to report on that, is that correct?

MR. KETCHUM: I would characterize it just a little bit differently, Mr. MacDougall. We were, as we said yesterday, and that part is correct, commissioned to do a study by NB Power in '93 to study various methods.
And as I said yesterday, the results of that method is what is reported here. And we selected the peaker credit

method as being most appropriate at that time for the integrated utility at that time.

The Board did not rule on that submission. And so it does however more or less coincidentally, I would have to say, sort of support the 40/60 demand energy split that the Board had previously approved.

Q.308 - Okay. I guess I'm a little confused. And maybe I will see if I can get the right references here, a little out of order of my questions, to follow up on that. I think it is in A-14. This is the Reed Report that was done at the time.

And I think it is appendix 2. So A-14, appendix 2. And if we could go to tab Roman Numeral IV in appendix 2, page 1. So it will be Roman Numeral IV-1.

MR. KETCHUM: Yes. I have that.

Q.309 - Okay. Now this is the Reed Report which we are referring to and which you were one of the authors, correct?

MR. KETCHUM: That is correct.

Q.310 - Okay. And then about halfway down the first paragraph I would just like to read in. "The Board recognized that the decision to invest in and construct capital-intensive plant is substantially driven by the energy requirements of the NB Power system. And therefore these costs should not be classified as 100 percent demand related. The Board did however express reservations concerning the reasoning and methods by which NB Power derived its 40/60 split for these costs and ordered NB Power to research further the proper classification percentages which should be used. The Board orders NB Power to prepare a comprehensive study supporting the 40/60 split on both a current and future basis." Correct?

MR. KETCHUM: That is an accurate reading of that, yes.

Q.311 - And this report that you prepared was in response to that Board request, correct?

MR. KETCHUM: That is correct.

Q.312 - And then if we can go to page Roman Number IV-21. And just for clarification this section Roman Number IV is dealing with generation classification?

MR. KETCHUM: Yes. That is correct.

Q.313 - Which essentially is a fixed cost of generation plant?

MR. KETCHUM: That is correct.

Q.314 - Okay. And then if we go to the second paragraph. And again I would like to read this. "Based on RCG's analysis of the various methods for classifying fixed production cost, including all of the evidence presented in this chapter, the most appropriate method for NB Power at this time is the peaker credit method. Therefore this method was used to model the system with a future configuration including the Belledune unit. This analysis is in response to the Board's directive to provide support for the production cost classification on a future basis as referenced at the outset of this chapter." Correct?

MR. KETCHUM: And that again is an accurate reading.

Q.315 - And the peaker credit method that you said was most appropriate for the NB Power system at that time also led to a 40/60 demand energy split, correct?

MR. KETCHUM: No. I wouldn't say that is correct. It led to a 39/61 split.

Q.316 - Pardon?

MR. KETCHUM: It led to a 39/61 split.

Q.317 - I apologize. I should have said approximately a 40/60 split. My apologies.

MR. KETCHUM: That was the conclusion of the report at the time, for NB Power at the time. And that was the methodology that Reed Consulting Group felt was most appropriate under the circumstances.

That report was submitted to the Board. But again there was no decision subsequent to that giving the Board's approval to the peaker credit method or any other method.

Q.318 - Did the Board ever come back to NB Power and tell them to stop using the 40/60 demand energy split subsequent to the filing of your report?

MR. KETCHUM: No, it did not. But the 40/60 demand energy split again was not the finding of the report. That was the Board's approved approach prior to the report being filed or being done.

Q.319 - But, Mr. Ketchum, the question I read you from page 1, and we can go back to it, is the whole essence of why you were asked to do this was because the Board had an issue with whether the 40/60 demand energy split was appropriate.

And your conclusion was that the peaker credit method was appropriate and showed a number 39/61. Are you saying that what you were telling the Board there was that the peaker credit method wasn't appropriate support for the 40/60 split?

MR. KETCHUM: No. I didn't say that it wasn't appropriate. I simply said that the Board didn't necessarily use or rule on that. What they did use is what they had used previously.

Q.320 - Okay. I will leave that there, Mr. Ketchum. Going back just to some of the comments we were making about the equivalent peaker method. I would just like to ask a couple of questions. I think I will come back to these later on as well. Mr. Larlee, these are probably more for you than for Mr. Ketchum.

As I understand it a generation planner looks at the tradeoff between lower cost capital plant, such as a combustion turbine which has higher cost fuel and is generally a peaker, maybe in an intermediate plant, as opposed to higher cost capital plant such as a base load coal or nuclear plant which has lower cost fuel. Is that correct?

MR. LARLEE: I think that is a fair description of what a system planner would do, yes.

Q.321 - Okay. And again I'm going to come back to some of these questions later along another line. But just to set a little basic. So there is a tradeoff between capital and fuel costs?

MR. LARLEE: Yes.

Q.322 - And if we can go to your evidence which again I think is in A-3. Actually, I apologize Mr. Chair, if we could go to Mr. Ketchum's evidence, which is -- it's also in A-3. It's just a change in who I was asking the questions to there. Page 5, line 17.

And again this was a continuation, Mr. Ketchum, of the earlier quotes that I was coming -- making comments on from on this page. And here I guess starting at page 15 you say, for example, one can buy a peaking unit with low fixed costs and relatively high fuel costs. Or one can buy a nuclear unit with very high fixed costs and low fuel costs. The least cost mix is determined by reference to the hourly demand and energy requirement characteristics of the system throughout the year.

And is that consistent with what you understand a generation planner would be looking for if he was using the peaker credit method, the least cost mix?

MR. KETCHUM: I wouldn't put the peaker credit method on the end of your question. But it's the kind of criteria that system planners will use to design the system generation mix, whether it has a peaker in it or not.

Q.323 - That's fine. That's the system planner's ultimate goal?

MR. KETCHUM: Yes, sir.

Q.324 - Thank you. And, Mr. Ketchum, if we could go to A-11, EGNB IR-40?

CHAIRMAN: A-11?

Q.325 - A-11, EGNB IR-40, Mr. Chair. 40. And, Mr. Ketchum, there in the first paragraph you make some references to various appendices. And then you say, the updated NARUC Electric Utility Cost Allocation Manual, page 53, you can refer to that for simple examples of the cost trade-off

analysis that is a fundamental precept of generation system planning. Correct?
MR. KETCHUM: That what it says in that response, Mr. MacDougall, yes.
Q.326 - And I would just like to ask you and then Mr. Larlee if you each agree that the cost trade-up analysis is a fundamental precept of generation system planning?
MR. KETCHUM: I would agree with that characterization, yes.
Q.327 - And Mr. Larlee?
MR. LARLEE: I would just like to look at what the NARUC manual says there.
Q.328 - Certainly.
MR. LARLEE: Could you repeat the question, please?
Q.329 - Sure. Just to go to the quote here. I was just wondering if you could confirm whether it's your view that the cost trade-up analysis is a fundamental precept -- and I am concentrating on fundamental precept of generation system planning?
MR. LARLEE: That's my understanding of the system planning process, yes.
Q.330 - Than you. Now if we could go to A-16, Volume 1 of 2 in the second round?
CHAIRMAN: Mr. MacDougall, when you get another volume out, if we -- if you could tell us we are not going to be using

one of ones that are presently piled up, we would be much appreciated.

MR. MACDOUGALL: Oh, the only one you need to keep in front of you, Mr. Chair, I think is the one that has the NARUC manual. The other ones I will just be referring to from time to time. And I apologize.

CHAIRMAN: No problem. And now the one that you just called for, what --

MR. MACDOUGALL: Was A-16, Volume -- it's Volume 1 of 2 in the second round of the IRs.

CHAIRMAN: Yes. And the interrogatory?

MR. MACDOUGALL: PI second round IR-59-A.

Q.331 - And, Mr. Ketchum, in response to this information request dealing with the deemed proper 46/60 split of demand energy, you are talking about Point Lepreau and the fixed O&M costs. Your response was that the 40/60 demand energy split has been applied to Point Lepreau in accordance with the PUB approved classification of fixed costs, which was an approach applied to all generation fixed costs. Correct?

MR. KETCHUM: That's not exactly what the response says.

Q.332 - Okay. I apologize. I was reading that from my notes. I will read the response. Thee 40/60 split has been applied in accordance with the PUB approved classification of fixed costs, which was an approach applied to all generation fixed costs?

A. Yes. Exactly.

Q.333 - However, my understanding is that the generation, the Genco generation fixed costs were classified as 100 percent demand. They weren't classified in accordance with this for the purposes of Disco's current CCAS, correct?

MR. KETCHUM: That's correct.

Q.334 - And my understanding for the reason why Disco is proposing it be done this way, was the way the contract between Genco and Disco works?

MR. KETCHUM: Yes. As I explained yesterday, I hope fairly clearly, we -- Disco had to look at the Point Lepreau contract in a different way. They did the split of the demand and energy portions that Mr. Larlee was just talking about a few minutes ago first, and then applied the Board approved 40/60 classification to the fixed portion.

For the Genco contracts the PPA was the guiding factor in terms of classification. And for the Genco fixed O&M that was also built on an energy basis, Disco also classified that fixed cost using the 40/60 approved method.

Q.335 - Okay. If we could go now then, Mr. Ketchum, I think we are still in A-16 to EGNB second round IR-6. That is EGNB 6. Okay. Mr. Ketchum, in there we are just restating what we have just said here that the Generation demand costs were classified 100 percent demand because that was consistent with the structure of the Genco PPA, correct?

MR. KETCHUM: That's correct.

Q.336 - And just to get on the record, the questions as explained why the 254,636,000 Genco firm demand costs are classified 100 percent demand. So we are talking about in excess of $250 million of firm demand costs, correct?

MR. KETCHUM: Yes. And I might point out there is also 387, 243,000 of energy costs associated with that contract as well.

Q.337 - Well, yes. But we are talking about fixed production costs here, right?

MR. KETCHUM: Right.

Q.338 - So energy costs have nothing to do with fixed production costs?

MR. KETCHUM: No. But I was trying to --

Q.339 - I know.

MR. KETCHUM: -- put the number in context. I thought that was what you were driving at. It's a lot of money.

Q.340 - No, I am talking about the amount that's being classified 100 percent demand.
MR. KETCHUM: Yes. You are correct.
Q.341 - And you are not classifying 40/60. So these are fixed Generation production costs. My whole discussion here is generally on fixed generation production costs.
MR. KETCHUM: Yes. Thank you.
MR. LARLEE: I would just like to offer clarification. The -- you are using the term fixed production costs. These are fixed demand charges flowing from the PPA.
Q.342 - I think that is philosophically where we have some of the dispute. The PPA costs are the costs of the generation plant billed to you, correct?
MR. LARLEE: The PPAs are what they are. And Disco pays what the PPAs say what we have to pay. And those dollars that you are referring to are the demand charges related to that PPA.
Q.343 - Okay. In the way that you are doing your CCS they are the demand charges related to the PPA. Okay. That's fair. Let me then just digress for a minute. If you had something else, Mr. Larlee, go ahead.
Let's talk a bit about that. Because I think this is where there is a fundamental difference and the Board has to be very clear on what you are doing are these as build

charges.
Let's just talk a bit about the PPAs. I will just move my questions ahead since you raised that.
The PPAs are related to the so called heritage assets of NB Power, existing NB Power Generation facility?
MR. LARLEE: That's my understanding of the PPAs, yes.
Q.344 - Okay. And I can bring you to a reference here but maybe if you can just confirm this, we don't have to go to it. But my understanding from the Disco business plan is that NB Power isn't forecasting any capacity deficiency until about 2014, 2015. Is that correct?
MR. LARLEE: Yes, that's correct.
Q.345 - Okay. So over the next little while we are talking about using the same generation assets now for the next number of years, correct? Just generally serve the load of New Brunswick?
MR. LARLEE: Yes, that's correct.
Q.346 - So largely the same plant but maybe the exception -- the one major exception being Lepreau which is a refurbishment of the Lepreau plant. But that's the plant that's going to serve the needs of Disco for the majority of that coming year?
MR. LARLEE: The current supply resource balance indicates that we don't need any new capacity until '14, '15.

Q.347 - And as we went through this debate a long time ago but I think should be clear for the Board, this Board had no input into the terms of the PPAs, correct?

MR. LARLEE: That's my understanding.

Q.348 - Thank you. Now, Mr. Ketchum, coming back to where we were, talking about the demand energy splits with respect to the various PPAs or generation plants as I may be referring to them, could we look at page 7 of your evidence? Again that is A-3.

MR. SOLLOWS: I just put that away.

Q.349 - Now what I would like to concentrate on here is just to get very clear the percentage of demand and energy and how it is being classified and why, so we are all clear of the rationale. And I think you have been very clear to date. I just want to get some of the numbers on the record.

If we look at page 7, lines 21 to 24. On the page before that, you know, in the other couple of paragraphs above, you talked about what has been done with respect to Genco and what has been done with respect to the Nuco PPAs. And then you go on to say that the above classification of the Genco contract fixed costs shows an 87/13 demand energy overall.

And my understanding is the reason that is because some of the fixed costs, some of the fixed O&M costs were credited partially to energy, correct?

MR. KETCHUM: That is correct.

Q.350 - Okay. So you have an overall fixed cost 87/13 split and the nuclear cost at a 40/60 split that results at a weighted average demand energy classification of 68/32, correct?

MR. KETCHUM: We have to put in the word fixed cost for nuclear.

Q.351 - Yes. I apologize.

MR. KETCHUM: Yes. Now that is the split of the -- again the fixed cost piece or the demand cost piece, that last number. We have to make sure that is understood.

Q.352 - Yes.

MR. KETCHUM: Overall, as we would see on schedule 5.1 for Mr. Larlee, the overall split, when you use all of the direct assignments and energy and so on and so forth from the PPAs comes out to be 34 percent demand, 66 percent energy.

Q.353 - Okay. But just to get clear, I think you are raising the same point you raised before. I'm talking about generation fixed cost.

MR. KETCHUM: Yes.

Q.354 - And that is the 40/60 demand split that was at issue

in front of this Board before. There wasn't a split of all costs.
The question the Board posed in 1992 was to come back and tell us whether the 40/60 demand energy split is appropriate for fixed generation costs. That is where we have an issue, correct?
MR. KETCHUM: That's correct.
Q.355 - Thank you. So maybe we could stick with that. Now that is the quote I'm asking my questions about.
MR. KETCHUM: Okay. I just thought I was adding some clarification about the total classification of generation.
Q.356 - It is useful. And that is not the issue that we are having. And I think that that is clear to everybody.
So if we could -- let me do this. If we could go to A-16. And here I'm going to look at PI, second round IR 59-B. Yes. PI, second round IR 59-B.
MR. SOLLOWS: You have been there before.
MR. MACDOUGALL: I have. I'm coming back. But I was trying to clear the binders. So we are coming back to that question for another purpose, Commissioner Sollows.
Q.357 - And I'm going to go back and forth. But I'm going to do it in the same binder which I think will be helpful.
I'm also going to want to subsequently refer to EGNB IR 36

which is in the same binder, okay.

So if we can look at 59-B, here, Mr. Ketchum, you state "Production cost classification methods for class allocation studies are applied to all fixed costs in a given utility company's generation cost mix and not to individual plant. The peaker credit method is meant to apply to the entire portfolio, as it has been applied to fixed costs here and not on a unit by unit basis." Right?

MR. KETCHUM: That is what that response says, yes.

Q.358 - And when the response says "The peaker credit method is meant to apply to the entire portfolio, as it has been applied to fixed costs here", what do you mean by that? My understanding is that meant that the peaker credit method was applied to fixed cost. Explain to me if it doesn't mean that?

MR. KETCHUM: It means that as a general proposition the classification of the fixed cost in an integrated -- vertically integrated utility, or in this case for those costs that -- where the application of the 40/60 split was required is applied to those facilities.

Q.359 - So you are saying the peaker credit method, since you used the 40/60 split only for NUCO, you were talking about here being just NUCO?

MR. KETCHUM: As it turns out it is Nuclearco plus the fixed

O&M, where that classification is required. As a general proposition, if we were looking at a vertically integrated utility, what I'm saying is that you apply the same methodology in that case to all of the generation fixed costs.

Q.360 - Okay. But I guess your lead-in is the peaker credit method is meant to apply to the entire portfolio, as it has been applied to fixed cost here, and not on a unit by unit basis?

MR. KETCHUM: That is right, as a general proposition.

Q.361 - But you did not apply the peaker credit method to the entire portfolio here, did you?

MR. KETCHUM: No, we did not. We --

Q.362 - So what is the here? This answer doesn't seem to have been a general proposition. It says "As it has been applied to fixed cost here." Has the peaker credit method been applied by Disco to the entire portfolio of generation fixed or generation demand cost?

MR. KETCHUM: No, it has not.

Q.363 - Thank you. Now if we could turn back. And I think I was going to go back in the same volume to EGNB IR 36.

MR. DUMONT: Are you sure it is in A-16?

MR. MACDOUGALL: Yes, Mr. Dumont, A-16 EGNB IR 36. I believe the EGNB questions are the second tab in A-16.

The first tab is CME.

MR. DUMONT: I got it.

MR. MACDOUGALL: Thank you.

Q.364 - And here -- and I'm not sure who prepared the response. Because the response was asking essentially for an update on one of the tables out of the Reed study, which essentially was to use the peaker credit method coming out of that and apply it to NB Power's current system.

Mr. Larlee, I'm not sure if you or Mr. Ketchum responded to this, because it wasn't directed to an individual. So maybe whoever responded, so that I will know who to direct my questions to.

MR. LARLEE: That response was prepared under my direction. I did have some input from Mr. Ketchum just to get the details on how the analysis was done so that we could reproduce it as closely as possible.

Q.365 - Great. And so this is a reproduction as close as possible as to similar table in his report from '92 or '93?

MR. LARLEE: I believe so, yes.

Q.366 - Yes. And that is what you were asked to do. And we appreciate the response.

And here you are showing that currently, with the generation mix of plant in NB Power, at the end of the question, "The results of the attached analysis show the fixed cost classification of demand energy to be 38.98, 61.02." That is the number stated earlier I believe by Mr. Ketchum?

MR. LARLEE: I'm sorry. I'm going to have to ask you to repeat the question.

Q.367 - Sure. I guess all I'm saying is the results of this are highlighted in the last paragraph on page 1 of IR 36. And it just reads "The results of the attached analysis show the fixed cost classification of demand energy to be 38.98, 61.02." Essentially 39/61 as previously referenced by Mr. Ketchum, correct?

MR. MORRISON: Excuse me, Mr. MacDougall. I think there might be some confusion in the binders. I know that my binder doesn't have the analysis attached to it.

CHAIRMAN: The same for ours.

MR. MACDOUGALL: Mine does. I apologize again, Mr. Chair. But we have attached a generation plant. And this is not confidential. And I only have the materials that was provided to me by NB Power on these IR's.

CHAIRMAN: Mr. MacDougall, we will take our 15-minute break now. Perhaps the Secretary can check on that. But just before we do close and take our break, Mr. Ketchum, you were a principal of Reed Consulting at the time that the report we have been talking about here today was prepared, is that right?

MR. KETCHUM: That is correct, Mr. Chairman.

CHAIRMAN: Now to your knowledge when was that report first filed with this Board?

MR. KETCHUM: I believe it was in 1993. It may have been spring of '94. I'm not absolutely certain.

CHAIRMAN: Okay. Thank you. All right. We will take a 15-minute recess.

MR. MACDOUGALL: Thank you, Mr. Chairman.

(Recess - 10:30 a.m. - 10:45 a.m.)

CHAIRMAN: Have we figured out where the table 2(a) or the equivalent of it is?

MR. MORRISON: Yes, Mr. Chairman. The Secretary has them. They were sent out I think with instructions for people to update their binders. But like others, I probably didn't do it, so.

Mr. Chairman, just before Mr. MacDougall resumes, you had a question about the filing of the Reed report. My information is that the amended report or the final version of the report was filed with the Board on July 15th 1993 and it is found in exhibit A-14 at appendix 2 and 3.

There may be some confusion because there was a second report on rate design issues, I think it was called an analysis of specified rate design issues for NB Power, which was only filed on July 14th 2005. But the report that you were referencing was filed on July 15th 1993.

CHAIRMAN: Thank you, Mr. Morrison. Go ahead, Mr. MacDougall.

Q.368 - Thank you, Mr. Chair. Mr. Larlee, just I guess to come back because I don't think we ended the question before we realized some people didn't have the analysis attached. The IR response is two pages. One page is the response, the second page the analysis. And just want to get you to confirm that the results of the analysis, as you indicate in the second paragraph: The results of the attached analysis show the fixed costs classification of a demand energy to be 38.98 demand, 61.02 energy. Correct?

MR. LARLEE: Yes. I would just like to add one clarification. We were only able to update this information to 2002.

Q.369 - Okay.

MR. LARLEE: The reason for that was because the index that the Reed Consulting had used in the previous analysis, the Handy-Whitman Electric Utility Price Construction Index was only available up to that time.

Q.370 - But you have updated this as best you can with respect to the NB Power generation plant?

MR. LARLEE: Yes.

Q.371 - And you have come up with a -- to be very clear, as Mr. Ketchum is making me be, 38.98 to 61.02 demand energy split arriving out of that analysis?

MR. LARLEE: That is what the analysis shows, yes.

Q.372 - Great. Now if we could go to the next page which is the analysis and we see those numbers at the bottom, 38.98, 61.02. Correct?

MR. LARLEE: Yes.

Q.373 - When I was talking earlier to Mr. Ketchum about applying them to the entire production portfolio, even though it is applied to the production portfolio, it is developed based on the various plants. Correct? There is not an identical allocation in every plant here that is equal to 38.98, 61.02. Correct?

MR. LARLEE: That is correct. Perhaps it would be useful if I just took the Board down through -- help them explain how this is done. It is --

Q.374 - That would be --

MR. LARLEE: -- a lot of numbers here. It could be quite confusing but it is actually a relatively simple analysis.

Q.375 - I actually think it is and I think that would be useful. Just before you do that, just to make sure. And the top says "Generating plant cost allocation analysis peaker credit method". That is what this analysis that you are going to explain to the Board is. Correct?

MR. LARLEE: Correct.

Q.376 - Great.

MR. LARLEE: Basically the analysis is two steps. All of the plants that are used to meet peak in capacity are averaged and the dollar per kilowatt value is calculated. Once that value is calculated, and I will just draw your eye to it. It is if you look at the first section of generating plants, there is a sub-total, sort of under the peakers heading, the sub-total. And if you move over three or four columns you will see under dollars per kilowatt 802. Basically what the analysis is saying is that the average cost of a peaker is 802. $802 per kilowatt.

The remainder in the analysis then calculates the dollars per kilowatt for all the other plants, base load and intermediate plants, subtracts off the $802 per kilowatt under the assumption that the investment in those plants up to that level, up to the $800 level, is for peaking capacity, the remaining investment is basically to for lower energy prices.

And then finally these values are averaged and divided to get the 38.98 to 61.02.

Q.377 - Great. Thank you very much, Mr. Larlee. I think I just want to talk briefly about the allocation -- the use of the 40/60 demand energy split for the Nuco costs arising out of the PPAs, as I understand you are doing it as opposed to the 100 percent demand energy split arising out of the PPAs for Genco. Is it your understanding that the Nuclearco PPA is take or pay up to the 80 percent capacity factor?

MR. LARLEE: My understanding is is that all of the energy that Point Lepreau produces Disco much purchase. So rather than put a catch phrase on it I guess I would just rather explain it like that. That is my understanding of the PPA.

Q.378 - You must purchase all of the energy?

MR. LARLEE: We must purchase all of the production, yes.

Q.379 - Why then is that not a fixed cost? Because you must purchase it so it is fixed, correct?

MR. LARLEE: Well it is not fixed because their production could vary.

Q.380 - But you have to buy everything that they produce, correct?

MR. LARLEE: That is correct, yes.

Q.381 - Okay. Yet you don't attribute that to 100 percent demand but it's -- you can't change that number. Whatever they produce, you purchase, correct? You must purchase it?

MR. LARLEE: We must purchase it, that is correct. Yes.

Q.382 - So I guess I want to understand why that isn't a demand cost. Why you don't think that it's --

MR. LARLEE: Well --

Q.383 - Because you must purchase it.

MR. LARLEE: The -- the idea I think behind classifying costs is you are taking a portion of your fixed costs and you are trying to recognize how the system is planned to balance your -- to balance your portfolio. When I looked at the 100 percent energy pricing of the Point Lepreau PPA, it seemed to me that it didn't make sense that here we have a plant with a significant -- with significant capacity related to it and pricing that didn't reflect that capacity. So I felt that really I had to revert back to some other means of classifying these costs because the pricing was obviously set up for some other reason than to reflect the actual true value of the plant which has energy value and capacity value.

And I thought that it was appropriate to use the Board approved 40/60 classification of the fixed costs related to the plant -- related to that PPA.

Q.384 - So it would be fair to say that you are sort of getting back to system planning or seeing what the system planner is doing in considering your cost allocation?

MR. LARLEE: Well I am not a system planner. What I was trying to do was look at it from a cost causation point of view. And that there is capacity value inherent in any supply. And that the PPA, the Point Lepreau PPA did not recognize the capacity value of that PPA.

Q.385 - Okay. But in fact it was a contract in which you have to take all of the energy produced from the Point Lepreau Nuclear Station. Correct?

MR. LARLEE: Yes, that is my understanding of the structure.

Q.386 - Okay. That is great. If we could go -- I think we are still in A-16. If we could now go to a CME second round IR. So that would be the first tab. So that is IR-4. And here if I can just read in CMEA -- 4A -- just if I can read in your answer here. You indicate that the export benefit credit is derived from Genco sales of both capacity and energy, and then you go on to say that the capacity portion is 24 million and the energy portion is 53 million, correct?

MR. LARLEE: Yes, that's what the response says.

Q.387 - Okay. So there is a capacity and an energy portion.

Now then if we could go to the next page which is CME IR 5. And here in talking about these classifications and third party credits being the third party export credit, your response is, the Genco PPA capacity related costs are not split between the demand and energy classifications. Genco PPA capacity related costs are classified as 100 percent demand. The classification of third party credits does mirror the classification of the Genco PPA capacity related costs by classifying third party credits as 100 percent demand, correct? So you are classifying them as 100 percent demand?

MR. LARLEE: Yes, that's correct.

Q.388 - Even though they are derived from both sales of capacity and energy?

MR. LARLEE: Genco derives the export benefits from their export sales through sales of both capacity and energy. That's what is being responded to or that's the context of the response in CME IR 4.

Q.389 - Correct. And you are classifying them 100 percent demand on the basis that you are also classifying the actual Genco demand costs as 100 percent demand. So you are saying for the credits to counter those they are classified essentially as 100 percent demand, correct?

MR. LARLEE: Sorry. You are going to have to repeat the question?

Q.390 - Well it appears from the answer here that you are saying the Genco capacity costs are classified 100 percent demand, so we have classified the credits as 100 percent demand so that they can be a credit to those costs?

MR. LARLEE: The rationale for classifying the export credits as 100 percent demand is because the PPA essentially puts that credit on the bill for Disco as a fixed credit. So I felt that there was a good cost causation link there to classify it as 100 percent demand.

Q.391 - Okay.

MR. LARLEE: Additionally the reason why Genco can benefit from export sales is that Disco has contracted for 100 percent of their capacity but doesn't use that capacity in all months of the year. So it's the fact that they have this capacity available that they can in fact make sales. So I felt that those two factors really made for a good rationale to classify it as 100 percent demand.

Q.392 - Okay. Well I would like to come back to that. If this Board doesn't accept the 100 percent demand classification of the fixed Genco PPA costs would you still suggest that they keep the 100 percent -- the third party credit cost of that as 100 percent demand?

MR. LARLEE: That would depend on the order that you apply the credit. As you apply the credit before you classified the Genco PPA costs then they would end up being classified by default. And I guess at this point I don't know.

Q.393 - Your primary rationale is that you are classifying these as billed in the same way you are classifying the Genco PPA costs as billed, although you did give us a second rationale?

MR. LARLEE: My rationale is they are billed as a fixed credit. So I treated them that way.

Q.394 - Okay. Mr. Chair, I think you could again put whatever binders you have there away except for the one that has the NARUC manual in it, which is A-14, appendix 7.

Mr. Larlee, I am just going to talk a bit about some of the quotes here from the NARUC manual and about how system planning goes on and how it's related to cost allocation in New Brunswick. In the third last paragraph about halfway down, it's the paragraph that starts, such time -- about halfway down it says -- I'm sorry -- on page 5, if I didn't give the page number. Sorry about that.

MR. MORRISON: Page 5 of?

Q.395 - Page 5 of the NARUC manual. Exhibit A-14, appendix 7, page 5. So the paragraph starts, such time differentiated

-- and about halfway down we have got a statement here, the challenge to the System Planner is to provide sufficient generating capacity to satisfy the peak demand while recognizing that much of the plant will not be needed for a large part of the day and year. Would you agree with that statement as a general proposition?
MR. LARLEE: Yes.
Q.396 - Would you agree with that statement as being generally applicable to New Brunswick?
MR. LARLEE: Yes, it's generally in New Brunswick, keeping in mind that Disco doesn't have any generation.
Q.397 - No. But Genco does. Genco does.
MR. LARLEE: Yes, Genco does.
Q.398 - And Genco and Disco are both owned by Holdco?
MR. LARLEE: Yes, that's true.
Q.399 - So the NB Power group of companies and the system itself as system planners planning the generation?
MR. LARLEE: That's correct. Yes.
Q.400 - And would you agree that in New Brunswick that the peak invariably comes on a cold winter day?
MR. LARLEE: Yes, it does.
Q.401 - And would you also agree that utilities typically plan a little extra capacity beyond the peak, essentially a reserve margin?

MR. LARLEE: Yes. There is regulations that require a certain very specific reserve margin.
Q.402 - And could you tell us what the reserve margin is in New Brunswick?
MR. LARLEE: It's really out of my area because --
Q.403 - That is fine. If I said it is around 20 percent would that -- could you take that subject to check?
MR. LARLEE: I could take that subject to check, yes.
Q.404 - Thank you. And you are familiar as a cost analyst with the term fixed costs?
MR. LARLEE: Yes.
Q.405 - And is that term generally applied to costs that do not vary with the amount of generation produced in a year? Would that be fair in a utility setting?
MR. LARLEE: I might state it slightly different, do not vary with the amount of energy produced in a year.
Q.406 - Okay. Fine. And would depreciation generally be considered a fixed cost?
MR. LARLEE: Yes.
Q.407 - Capital costs such as interest on debt?
MR. LARLEE: Yes.
Q.408 - And because the utility must build to meet the peak plus have some reserves, would you agree that many utility cost analysts allocate all generating fixed costs on a

measure of coincident peak?

MR. LARLEE: Yes. I think that's fair.

Q.409 - Would you also agree that when a utility planner decides it must build generating capacity to satisfy growing demand, it has a choice of a number of options of generating plants?

MR. LARLEE: Yes.

Q.410 - And is the choice of different technologies somewhat the premise for the peaker credit method that we talked about earlier?

MR. LARLEE: I believe so, yes, it is.

Q.411 - And would you agree that these different technologies are generally referred to as base load, peaking and intermediate plants?

MR. LARLEE: Yes. That's the general characterization of them.

Q.412 - Would you agree that base load plants tend to have high fixed costs but relatively low fuel costs?

MR. LARLEE: Yes.

Q.413 - Now let me read another statement from the NARUC manual. This is on the top of page 7. About halfway down, after they talk about other types of plant, they start talking about peaking plant, okay.

And it says "At the other extreme peaking plants are constructed to satisfy the demand that may occur only for a few hours of the year." Okay. "These plants must be easily loaded and unloaded onto the system, and since the hours of their operation are limited, must have low capital costs." Do you agree with those statements?

MR. LARLEE: Yes. I would agree with that.

Q.414 - And then it goes on to say that "Generally they also have high fuel costs such as gas turbines. Although hydroelectric stations with some reservoir capacity may also be constructed as peakers because of the ease of instantaneous operation." Would you agree with that as well?

MR. LARLEE: Yes. Again I'm not a system planner. But this is my general understanding.

Q.415 - That is fine. And so generally you would state that the NARUC manual is giving a fair characterization of a peaker plan?

MR. LARLEE: Yes.

Q.416 - Then it goes on about two lines down and it says "Intermediate plants, fossil fuel stations burning coal, oil and natural gas are dispatched less frequently than base load and more often than peakers."
Does that conform with your understanding of not just utilities in general but how New Brunswick planners have

generally viewed their system?

MR. LARLEE: Yes.

Q.417 - And now to get a little more technical, if we could go to page 5 of the manual. And this is where I know you will have expertise so you will be very helpful to us. Again back up in this third paragraph, such time differentiated graphs. About half-way down it says "The shape of the load duration curve over the year in large measure determines the utility planners choice of generating plant needed to satisfy customer demand." Do you agree with that statement?

MR. LARLEE: My understanding is that the planner would look at more than just the shape but as a general statement yes.

Q.418 - The shape is important though. It is an important piece of information.

MR. LARLEE: The shape is important but I mean, it is not just looking at a graph and making decisions. It is a very --

Q.419 - Fully understood?

MR. LARLEE: -- sophisticated and detailed analysis.

Q.420 - Yes. But he certainly would be looking at the load share -- the load duration curve and the load share?

MR. LARLEE: Yes.

Q.421 - Okay. Could you indicate where in your cost of service study you utilized the load duration curve or the load duration curve of any of the customer classes?
MR. LARLEE: A cost of service study is not system planning. Load duration curves don't come directly into doing the cost of service study. The load shape is factored into the study through the allocation factors for demand and energy.
Q.422 - So just talking about load factor again for a minute then. My understanding is that most if not all utilities like to encourage a high load factor because it minimizes costs. Is that a fair statement?
MR. LARLEE: A low load factor load encourages the use of base load plants which have lower energy costs.
Q.423 - No, high load factor load.
MR. LARLEE: Sorry, high load factor load.
Q.424 - Yes, high load factor load.
MR. LARLEE: High load factor load.
Q.425 - Minimizes your costs, correct?
MR. LARLEE: Let me restate that, just for the record. High load factor load encourages the use of base load plants which have lower fuel costs.
Q.426 - And the higher the load factor of the system, the more you spread your fixed costs over a larger base. Is that a

fair comment?

MR. LARLEE: You spread your fixed costs over higher energy sales.

Q.427 - Okay. And do plants run more efficiently when they run at a constant level without having to be cycled up and down?

MR. LARLEE: You are out of my area there.

Q.428 - Okay. Maybe we could take that subject to --

MR. LARLEE: It has been several years since I have stepped foot in a generating plant.

Q.429 - Okay. Mr. Ketchum, do you have any views on that? If we could just get it on the record that one of the two of you would think that plants run more efficiently when they run at a constant level without having to be cycled up and down.

MR. KETCHUM: Yes, ramping up and ramping down requires more energy inputs than running at a constant level.

Q.430 - Thank you. How is the load factor and the comments that I have just made reflect in your cost of service study, Mr. Larlee? The differentiation between the value of the high load factor or low load factor.

MR. LARLEE: In the cost of service study we estimated the demand contribution and the energy requirements for each rate class. The relative size of those contributions for each class essentially is what we would call the load factor.

So when the classified demand costs and classified energy costs are allocated to classes, the load factor comes into play as to the relative allocations of dollars.

Q.431 - Thank you. Just getting back to the utility planner's choice of generating plant, base load, peaker or intermediate plant, when a planner makes that choice, is it your understanding that what they are trying to do is to minimize total costs as opposed to minimizing fixed costs or fuel costs separately?

MR. LARLEE: Yes, it is my understanding that the planner is trying to minimize the total cost for the particular system that he is planning for.

Q.432 - Okay. And if a planner decides on a base load plant, we can generally say that the planner decided to incur more fixed costs to save fuel costs. Correct?

MR. LARLEE: Correct.

Q.433 - But the decision was to minimize total costs, not just the fuel costs. Correct?

MR. LARLEE: Correct.

Q.434 - So conversely, if a planner decided that the optimal choice was a peaker, could we say that the planner decided to incur more fuel costs in order to save on capital costs?

MR. LARLEE: Correct. That is the trade-off that we have been discussing.

Q.435 - Okay. And in your class cost allocation study, did you allocate any fixed costs on the basis of energy?

MR. LARLEE: Once the costs are classified as either demand or energy within the study, then the demand costs are allocated based on coincident peak demand and the energy costs are based on the energy requirements.

Q.436 - So you did allocate fixed costs in your CCAS on the basis of energy?

MR. LARLEE: If we look at the non-fuel --

Q.437 - That is what I am talking about.

MR. LARLEE: If we look at the non-fuel requirements under the Nuclearco PPA, for example, we classified those using the Board approved 40/60 split. 40 percent demand, 60 percent energy.

Q.438 - Yes.

MR. LARLEE: So that 60 percent portion was then allocated based on energy.

Q.439 - But the answer is yes, you have allocated certain fixed costs on the basis of energy in your CCAS?

MR. LARLEE: Prior to classification, yes.

Q.440 - Yes, that is what I'm --

MR. LARLEE: Yes.

Q.441 - Now in your CCAS, did you allocate any fuel costs on the basis of peak demand?

MR. LARLEE: No.

Q.442 - Okay.

MR. LARLEE: Fuel costs, there is no classification step for fuel costs. It's 100 percent assumed to be energy related.

Q.443 - Mr. Chair, I am taking questions out so my pause is worthwhile. So if you bear with me it will be helpful.
If we could turn now then still in the NARUC manual to chapter 4, which I believe page 35. Chapter 4 starts on page 33. I want to go to page 35. Just before doing that though, just so that we know where we are, chapter 4 is entitled "Embedded Cost Methods For Allocating Production Costs". Correct? On page 33?

MR. LARLEE: Yes, that is the title of the chapter.

Q.444 - I just want so that people had the focus for what we are talking about here. Embedded Cost Methods For Allocating Production Costs.
So on page 35, in the roman numeral on that page it talks about the classification of production function costs. Correct?

MR. LARLEE: Correct.

Q.445 - And then just below that, the NARUC manual states that production plant costs can be classified in two ways. Between costs that are demand related and those that are energy related. Correct?

MR. LARLEE: Correct.

Q.446 - And then if you look at the next couple of pages you will see it deals with two methods, a, the cost accounting approach and then if you flip over to page 38, b, the cost causation approach. Correct?

MR. LARLEE: Correct.

Q.447 - Now I was going to go through some of the wording here, Mr. Larlee. But maybe you could just quickly look at these and indicate to me which of these approaches is more reflective of what you carried out. And you may be familiar with this.

MR. LARLEE: I would say that the closest of the two is the cost causation approach.

Q.448 - Thank you. And in fact Mr. Marois yesterday talked a lot about cost causation, didn't he?

MR. LARLEE: Yes.

Q.449 - Great. Thank you. Now to my understanding again from reading this, and now that you have read through it, would you agree that the cost causation method is more complicated and sophisticated than the cost accounting approach? You are not just taking costs from a general ledger account. You are looking at low duration curves and things like that. Is that a fair comment, do you think?

MR. LARLEE: Just quickly looking, as it is described here, yes.

Q.450 - Yes. Great. Thank you. But we can assume then that the added complexity and sophistication of using a cost causation approach as opposed to a pure accounting approach is worth it in order to get a more accurate picture of who is causing what costs on the utility, correct?

MR. LARLEE: I don't believe that the NARUC manual actually says it prefers one method over the other.

Q.451 - No. I didn't say that it did. I'm just sort of saying do you believe that the added complexity of this method is worth it in order to get a more accurate picture of who is causing costs on a system? That is what I'm asking you, having confirmed that the approach you are taking is more along these lines.

You are trying to get, as it says on line -- the first line under Cost Causation on page 38. Cost causation is a phrase referring to an attempt to determine what or who is causing costs to be incurred by the utility. That is what you are trying to do, correct?

MR. LARLEE: Yes.

Q.452 - So would you agree that a cost causation approach that veers too much toward simplicity is sacrificing some accuracy, like if you made a whole host of assumptions? You might have to make some assumptions. But you would want to limit them in order to get true cost causation analysis, correct?

MR. LARLEE: As you are indicating in your question, any cost allocation study has a certain number of assumptions.

Q.453 - But here the goal is to try and determine closest who is causing the cost to be incurred by the utility in this system, in this methodology?

MR. LARLEE: That is -- that is correct. Yes.

Q.454 - Okay. That is what I'm getting at. Again, Mr. Chair, I'm ticking it off. So silence is golden in these circumstances. Mr. Chair, I'm taking a lot of stuff out here. So if you could just bear with me.

CHAIRMAN: Mr. MacDougall, take your time.

MR. MACDOUGALL: Thank you.

CHAIRMAN: While you are doing that, when we went through one of the charts previously, where I believe where the costs or capacity of Millbank was discussed, it was 199,000, wasn't it, Commissioner Sollows?

And from -- to our understanding there are three units there or four -- four.

MR. LARLEE: Four units at Millbank, yes. And they are approximately 100 megawatts each. My understanding again is that two of those units are contracted to Hydro Quebec. And Hydro Quebec at peak times can call on them. So they are not included as capacity in the New Brunswick system.

MR. SOLLOWS: And that is the original contract?

MR. LARLEE: I believe it is still the original contract that those plants built under.

MR. MACDOUGALL: Mr. Chair, I'm ready at anytime.

CHAIRMAN: By all means. Go ahead.

MR. MACDOUGALL: Thank you for the indulgence.

Q.455 - If we could go now to page 53 of the NARUC manual. And Mr. Larlee, here if we look over on the facing page 52 we are under the title "Equivalent Peaker Methods", correct?

MR. LARLEE: Yes. That is the section.

Q.456 - Okay. So we are talking about equivalent peaker. And on page 53 there is a heading, second paragraph, "Data Requirement", correct?

MR. LARLEE: Yes.

Q.457 - And I would just like to read this into the record and see if you can agree. "This energy weighting method takes a different tack towards production plant cost allocation, relying more heavily on system planning data in addition to load research data."

And here is the key question for you. The cost of service analyst must become familiar with system expansion criteria and justify his cost classification on system planning grounds. Do you agree that if one is using the equivalent peaker method that that is a true statement?

MR. LARLEE: I think we have to get back to the point that Mr. Ketchum was trying to make. And that is that the equivalent peaker method was used to verify, shall I say, the Board's 40/60 direction for classification.

Q.458 - Well, I would like to concentrate on this though. I would like to know. You are the cost of service analyst being put up here. I have asked you a bunch of questions on system planning.

We obviously have a little bit of dispute on the equivalent peaker method. But I think we have clarified some of it through our cross examination today.

So to the extent that it was used in any manner by NB Power, would you agree or disagree that the cost of service analyst has to be familiar with system planning expansion criteria and justify his cost classification on system planning grounds?

I'm not trying to be problematic. I just would like to know if you agree or disagree with that?

MR. LARLEE: In this case my classification was based on the premise that either 1) cost causation through the PPA's or 2) when that just simply wasn't viable I resorted to the Board-approved 40/60 classification.

That Board-approved classification was subsequently verified essentially by the consulting group after the Board's 1992 CARD decision.

Q.459 - On the basis of the equivalent peaker method it was verified?

MR. LARLEE: That is correct. Reed Consulting determined that the equivalent peaker method was a reasonable approach for NB Power at the time and used that particular analysis.

Q.460 - Mr. Ketchum, then when your analysts and yourself and the authors of your report used the equivalent peaker method or the peaker credit method, which are equivalent I guess, at the time to support the 40/60 split, were you of the view that the cost of service analysts doing that should have been familiar with the system expansion criteria and justify their cost classification on system planning grounds of New Brunswick Power?

MR. KETCHUM: If the analysts at that time were to do that analysis it would require a certain amount of fundamental understanding of the process. And at the time there was consultation with the system planners at NB Power.

Q.461 - Thank you, Mr. Ketchum. So is it fair to say that a system expansion plan can sometimes be called an integrated resource plan or that they are similar?

MR. LARLEE: Well, the term integrated and integrated resource plan refers to looking at as well not only the supply side but the demand side --

Q.462 - Yes.

MR. LARLEE: -- of the equation. So that is where the term integrated comes. So the supply side, the system planning side is part of it, part of IRP in the integrated resource plan.

Q.463 - So if you had an IRP though you would have had system planning that goes into it on the supply side?

MR. LARLEE: Absolutely, yes.

Q.464 - Thank you very much. that was very helpful. And that is a term NB Power is familiar integrated resource plan?

MR. LARLEE: Disco is familiar with it and Genco is familiar with it, yes.

Q.465 - Yes. Could you tell me how you or Disco utilized the most recent Point Lepreau IRP in conducting your cost of service study analysis?

MR. LARLEE: I didn't factor the IRP into the cost allocation study.

Q.466 - Mr. Larlee, just going into -- I'm just going to sort of give you a hypothetical here. But the numbers are all small round numbers. So I think it should be easy to follow through.

A utility can choose to construct one of a variety of plants like we talked about, combustion turbines, combined cycle, base load units, correct, as we talked about earlier?

MR. LARLEE: Correct.

Q.467 - And the choice of unit depends on in part the energy load to be served, i.e. peak load or base load, correct?

MR. LARLEE: Yes.

Q.468 - Now a peak load of relatively brief duration, and let's use for an example 1,500 hours per year, and let's say it could be served most economically by a CT unit. Just use that in a hypothetical, okay.

And that we had a peak load of intermediate duration of say 1,500 hours to 4,000 hours per year might be most economically served by a combined cycle unit. Do you have those two aspects of the hypothetical?

MR. LARLEE: I just want to perhaps clarify my previous response in that when the system planner is looking at the next unit he is looking at the total load.

Q.469 - Yes.

MR. LARLEE: He is not looking at the next unit to supply a particular section of the load. He is looking at the total load.

Q.470 - Okay. That is fair. So let's say my hypothetical where you would have a peak load of a relatively brief duration, say for example 1,500 hours that could be served most economically by a CT unit, and then you determined that a load of intermediate duration of say -- from 1,500 to 4,000 hours could be served most economically by a combined cycle, and over 4,000 could be served most economically by a base load plant.

So essentially we have 1,500 hours, 1,500 to 4,000 and 4,000 and above. And the three units we are talking about are a CT, a combined cycle and a base load unit?

MR. LARLEE: Okay.

Q.471 - Okay. In that hypothetical would you understand what I mean if I say that 1,500 hours is the break-even point between the CT and the combined cycle?

MR. LARLEE: Oh, I believe so. I would understand that to mean that if the CT is going to -- or if the load duration is there for 1,500 hours or less, then the CT would

provide the most economic means to supply that load.
Q.472 - Exactly. And the CC would run -- would need -- you would have to have load that runs at least 1,500 hours before the extra capital cost for the CC -- before the extra capital cost for the CC was outweighed by the fuel cost on the CT, correct?
MR. LARLEE: Yes. I mean, I will accept that as your assumptions in your hypothetical --
Q.473 - Sure.
MR. LARLEE: -- construct here.
Q.474 - I just want to know did you employ the concept of break-even points in your CCAS?
MR. LARLEE: No.
Q.475 - Now if we go to page 53. I think we are still on page 53 of the NARUC manual. You will see under the heading "A Digression on System Planning" with reference to plant cost allocation. And in the second paragraph -- that is essentially where my construct came from. And that is set out under the equivalent peaker method section of the manual, correct?
MR. LARLEE: Yes, I see that.
Q.476 - Do you believe that a prudent utility planner would plan on installing or building a base load unit if the break-even point between the base load plant and the

combustion turbine were greater than 8,760 hours?

MR. LARLEE: No. It doesn't seem to make a lot of sense to me.

Q.477 - No. Because that would be more than all the hours in the year?

MR. LARLEE: Right. Correct.

Q.478 - Now if we could go to page 55 of the manual. At the very top. I would just like to read this out. And just so that you -- you can flip back to page 52. We are still dealing with the equivalent peaker methods. It's continuing on here. The top of page 53.

The equivalent peaker -- the top of page 55, I apologize.

55. The equivalent peaker classification method applied in the example above -- and that's the table previous to it -- ignores the fuel savings that accrue from running a base unit rather than a peaker. Discussions with planners can help incorporate the effects of fuel savings into the classification.

And my question to you is did you have any discussion with planners to see how you could incorporate fuel savings from a break even analysis into your cost classification?

MR. LARLEE: No.

MR. MACDOUGALL: Mr. Chair, that's all of our questions. I want to thank the panel for their answers.

CHAIRMAN: Thank you, Mr. MacDougall. Perhaps we can take our luncheon break now and come back at 1:00 o'clock.

(11:45 p.m. - 1:00 p.m. - Recess)

CHAIRMAN: Mr. Morrison, anything preliminary?

MR. MORRISON: No, Mr. Chairman.

CHAIRMAN: Board counsel has indicated to me that there is some question of when Intervenors will be able to proceed. I anticipate that Mr. Gorman is ready to go.

MR. GORMAN: Yes, Mr. Chairman.

CHAIRMAN: Mr. Hyslop?

MR. HYSLOP: Yes, Mr. Chairman. I have -- as the Board probably realized, I have retained an expert out of Massachussetts to assist me, particularly with regard to the customer class allocation study.

In best faith of scheduling we anticipated the majority of our cross examination would take place this week, although I appreciate the way -- or next week when things get going. And we had him scheduled to arrive in Saint John Sunday to properly prepare cross examination at least for the two witnesses who are here now without Mr. Marois.

I can prepare some cross examination on the rate design issues for Mr. Marois tomorrow when he returns but my preference of course is to rely on the expertise that I have -- with apologies, I have misjudged the timetable that when we would require him to be here.

I also note that not only will he be here next week, but I expect I will have to have him back when we do Dr. Rosenberg and from what I hear on the scheduling of that, I will have to have him back when he himself is subjected to cross examination.

So from my point of view, my preference is to have our cross examination next Tuesday. Having said that, we can deal with some issues with Mr. Marois here tomorrow when he returns.

CHAIRMAN: Anyone else going to be questioning this panel or Mr. Marois, of the Intervenors?

MR. HYSLOP: Mr. Peacock is not back. But I do understand he may have some cross examination, Mr. Chair.

CHAIRMAN: He does come in late, doesn't he?

MR. MORRISON: Mr. Chair, we did have some informal discussions at the lunch hour and I think we are going to continue them after we conclude this afternoon, on scheduling issues and perhaps we can have a proposal that we can put to the Board tomorrow. There is some issues about timing with respect to when certain Intervenor experts are available and we have to work around those.

But we are trying to come up with a schedule that maximizes the hearing time that we have without throwing the order of cross and so on completely out the window.

So we are going to try to work on that this afternoon and have something to Mr. MacNutt and to the Board perhaps first thing in the morning.

CHAIRMAN: How long is your cross, Mr. Gorman?

MR. GORMAN: I would expect about an hour.

CHAIRMAN: Okay. That is by MacNutt count, that is two, I guess. No, I am just wondering if maybe I had a question of Mr. MacNutt, is that if you had a moment to speak with the Public Intervenor and Mr. Gorman, you might find some matters that have not been canvassed to date or that they have no desire to canvass, that you might be able to fill in today or tomorrow with. That is a question.

MR. MACNUTT: I think, Mr. Chairman, we have a preparation session scheduled for this afternoon. We are in a draft mode but I have been advised that we still need to have this afternoon's consultation before --

CHAIRMAN: Missed the last bit of what you said, Mr. MacNutt.

MR. MACNUTT: We are in a draft mode with several questions but I have been advised we still need to have our meeting this afternoon before we commence.

CHAIRMAN: Okay. Mr. Gorman, go ahead.

MR. MORRISON: Perhaps while we are having a brief discussion, Mr. Chairman, whether Mr. MacNutt could indicate whether he intends to cross examine Mr. Marois tomorrow. I guess we are -- it was our thought process that we would sort of finish up Marois tomorrow if possible.

CHAIRMAN: Well let's wait until Mr. Gorman's cross is through. Go ahead.

CROSS EXAMINATION BY MR. GORMAN

MR. GORMAN: Thank you, Mr. Chairman and members of the Board. With respect to cross examination of Mr. Marois, I would anticipate doing my cross examination of him tomorrow morning, if that is helpful to the Board to know that.

Q.479 - Good afternoon, Mr. Larlee and Mr. Ketchum.

MR. KETCHUM: Good afternoon, sir.

Q.480 - I would ask first if you would turn to exhibit A-3 and I am referring to tab 3 of the evidence of Mr. Larlee. Mr. Larlee, just at the beginning of your evidence you indicate that you are employed with the New Brunswick Power Holding Corporation and not the Applicant in this matter?

MR. LARLEE: That is correct. I am currently employed with

NB Power Holding Company.

Q.481 - And since your graduation from university, effectively you have been employed with NB Power or Holdco?

MR. LARLEE: Yes, that's true.

Q.482 - Did you participate in the class cost allocation study that was prepared by NB Power in 1991 and used during the November 1991 Generic Hearing before the New Brunswick Board of Commissioners of Public Utilities concerning cost allocation and rate design process?

MR. LARLEE: No, I did not. At that time my employment with NB Power was as a design engineer in the transmission system. I joined the load forecast and rates group I believe it was in December of '92.

Q.483 - So would the study that you are putting before the Board for this hearing, would that be the first study that you have done?

MR. LARLEE: No. I was involved with literally all of the studies in the intervening years that we have filed as part of the evidence in this proceeding.

Q.484 - And that would commence when? Your involvement is what I mean.

MR. LARLEE: They would commence with the 92/93 study, I believe.

Q.485 - Thank you. At page 1 of your direct evidence, and I am looking at line 14, you say my evidence introduces the New Brunswick Power Distribution and Customer Service Corporation's class cost allocation study.

And I am I guess wondering about the word "introduces". It doesn't say that you prepared it. It says that you are introducing it. Can you tell me who was involved in the preparation of that report? Was it you or was it you in collaboration with others?

MR. LARLEE: I was involved with the report. I was involved in collaboration with others. But I was also the lead in developing the cost allocation study.

Q.486 - So you were the lead. The others who were involved in the preparation, would they all report organizationally to you?

MR. LARLEE: Yes.

Q.487 - Okay, Mr. Larlee, I would ask you to turn to page 3 of your pre-filed evidence. And I am referring to line number 7. You say that the effort in preparation for restructuring has allowed for a clearer understanding and functionalization of costs.

Could you expand on this clearer understanding that you refer to?

MR. LARLEE: Yes. As I discussed briefly in my overview, restructuring basically eliminated the need to functionalize the production and transmission costs which was a key step in the previous studies. Because of restructuring those costs in great detail were analyzed through the whole process and separated out into the transmission company and Genco.

So as a result, there is no need to do that in a cost allocation study and I believe it lends for a clearer functionalization at the end of the day.

Q.488 - You refer to a clearer functionalization. What about a clearer understanding, which is I guess part of what you said in that statement?

MR. LARLEE: As a result of a clearer understanding, you have -- or sorry, clearer functionalization, you have a clearer understanding of the costs. I think that is the point I am trying to make.

Q.489 - So anyway, you would agree that the CCAS is used as a basis for differential rate adjustments between rate classes? That is the purpose of it?

MR. LARLEE: The purpose of the cost allocation study is to compare the allocated costs to the rate classes, compare that to the revenues received to the rate classes. So you end up with the revenue to cost ratio.

Q.490 - And then what is that revenue to cost ratio used for?

MR. LARLEE: And then the revenue to cost ratios, which are the result of the cost allocation study, then is one tool that is used in the rate design process.

Q.491 - And what would the other tools be?

MR. LARLEE: Well I think if you look at Mr. Marois' evidence, which is in A-3 under Mr. Marois' tab, perhaps we could go there?

Q.492 - Yes.

MR. LARLEE: The very first page, Mr. Marois lists the key objectives. So these are the other factors that came into play -- the key factors that came into play during the rate design process in this application.

Q.493 - Well, I guess sticking with Mr. Marois' evidence -- and he is not here today to answer this. And perhaps some of these questions may well end up being posed to him. He talks about key objectives. And I'm going to focus on the word "key". Are there other objectives that were considered other than the key ones?

MR. MORRISON: Mr. Chairman, I believe those questions were asked -- put to Mr. Marois yesterday. And I believe he answered them. If this witness can answer -- I just don't want to get into a situation where we are cross examining Mr. Larlee on evidence of Mr. Marois when Mr. Marois will be here tomorrow to answer those questions.

Q.494 - Fair enough. Mr. Larlee I guess is the one that brought me back to Mr. Marois' evidence. And I guess that is one of the difficulties that is posed when we have part of a panel present. But that is okay. I will defer to Mr. Marois on that.

If I could ask you to turn to addendum 3 of your report. Could you tell us what addendum 3 represents?

MR. LARLEE: Yes. What is going on here in addendum 3 is that Disco has three basic types of general costs. 1) the Disco general costs. Those are the costs within the operating company itself which are basically not related to any particular function. They are common costs such as corporate communications and regulatory, human resources and so forth.

Just for the record you will note here line 1 is "Rates and Load Forecasting" which is my group. At the time that the budget was prepared my group was in Disco. So that is why that is shown here.

The other type of costs are Holdco costs. And there is two types of those. 1) if you look at line -- or just above line 11 you will see a Holdco cost, corporate services. Those are the general corporate services costs. And you might characterize those as head office costs. It includes the CEO, finance, regulatory, the corporate regulatory costs, and legal and so forth.

And then the third type of cost, again that flows through Holdco, are the shared services costs. And these are the costs provided by Holdco's shared services organization that have been directly assigned to Holdco.

So what this schedule is trying to do is take these common costs and split out and allocate to the nondistribution customer classes a share of these costs.

And the reason why I have developed this schedule separately -- this is a new schedule that wasn't contained in the Board-approved cost allocation study from '91 and '92 -- is because under restructuring now there is a distinct line between distribution and transmission and wholesale customers.

And I couldn't use any type of asset-based allocation because in actual -- Disco doesn't really have or has very few assets related to serving those transmission and wholesale customers. All our distribution assets are used to service distribution customers.

So what this schedule does is detail line by line what I used as a basis to allocate the costs between the distribution customers and the wholesale and industrial transmission customers.

Q.495 - And the basis that you have used appears in the column on the far right under the word "basis"?

MR. LARLEE: Yes. I have put a brief description there of the basis used in each case.
Q.496 - And I guess what you have just said in your previous answer is effectively that these types of expenses, typically it is difficult to categorize them as demand, energy or customer-related. Is that really what you are saying?
MR. LARLEE: That is exactly correct, sir.
Q.497 - So would you agree that obviously allocating these types of costs would pose some challenges in preparation of this aspect of your study?
MR. LARLEE: Yes. It did pose a challenge.
Q.498 - Now if I can refer you to the last column in addendum 3 entitled "Basis". And if we start with the very first heading there, "Disco General Cost", line 1 is "Rates and Load Forecasting." And the basis that you have used is sales revenue?
MR. LARLEE: That is correct.
Q.499 - And could explain why you use sales revenue?
MR. LARLEE: Well, I felt that that was a reasonable way to represent the effort or the time on task between those three groupings, distribution, wholesale, industrial transmission.
Q.500 - Did you consider any other basis on which to allocate

those costs?

MR. LARLEE: Again I didn't -- normally I would use something related to assets. And in this case I really couldn't because of the unique nature. So I didn't prepare or do any analysis that I would consider a thorough consideration of alternatives, no.

Q.501 - So in a sense then using sales revenue as the basis for allocating the rates and load forecasting cost was somewhat -- would it be arbitrary? Would it be fair to say it was somewhat arbitrary?

MR. LARLEE: No. I wouldn't use the word arbitrary. I would use judgmental.

Q.502 - Okay. So in coming to the conclusion that sales revenue was the appropriate basis then this is your judgment that we are talking about or your team?

MR. LARLEE: Yes, primarily. Although I did consult others that I felt could contribute to the effort.

Q.503 - Were there any policy considerations there or -- when you say judgmental. I guess I'm looking for some indication as to what was the basis of coming to the conclusion that that was the appropriate basis?

MR. LARLEE: The primary basis is cost causation, so -- and given the practicalities of the information available. I felt that sales revenue was basically as good as it gets.

Just to clarify, there is no overriding policy issues driving me here other than I was tasked with preparing a cost allocation study that works on the fundamentals of cost causation.

Q.504 - Did you consider using total allocated costs as opposed to sales revenue?

MR. LARLEE: No, I did not.

Q.505 - Would that be reasonable?

MR. LARLEE: This is an allocation of Disco cost's primarily. And I really don't follow the rationale for using total allocated costs.

I think really where they are looking here is the work done within the Disco organization between these specific groups of customers. How can we divide it up? And I don't think total allocated cost is necessarily a good way to do that.

Q.506 - Would you say it is a bad way of doing it?

MR. LARLEE: No. I wouldn't use the word bad. It is another way of doing it. It wasn't the way I chose.

Q.507 - It is an option?

MR. LARLEE: It would be an option.

Q.508 - Okay. And then if I -- on the basis, if I go down that column, the next two items also use sales revenue. And could I take it from your previous answer that your rationale would be the same, you have used your judgment on that?

MR. LARLEE: Yes.

Q.509 - Then on line 4 under Regulatory I see that you have allocated it one-third to each?

MR. LARLEE: That is correct.

Q.510 - And that would result in a much larger number being attributed to the wholesale class than if you had for example been consistent and used sales revenue?

MR. LARLEE: Yes. Well, the use of one-third, obviously wholesale doesn't represent one-third of the revenue between distribution or wholesale industrial. So the one-third does result in a higher allocation.

My rationale for not using revenue in this case is simply that historically in these proceedings there has been three major groups involved, distribution customers, wholesale customers through the Municipal Utilities Association or representing the actual utilities themselves and the transmission customers, usually represented by the large industrial customers. So I felt it was a reasonable approach to simply divide the costs into three.

Q.511 - I want to talk about the first part of your answer. You said that clearly it wouldn't represent one-third of

the costs. Where would it fit? Where would the wholesale group fit in terms of a percentage, if you were using sales revenue for example? Would it be considerably less?
MR. LARLEE: Would you like me to work that out for you?
Q.512 - Could you?
MR. LARLEE: If it's all right with you, I will use round numbers. But using sales revenue, the allocation is about 10 percent. And using one-third, one-third, it is 33 1/3.
Q.513 - So it's quite a considerable difference?
MR. LARLEE: There is a difference.
Q.514 - The second part of your response to the last question that I wanted to ask you about is that you say that your rationale for allocating it on a 33 percent basis as opposed to say a 10 percent was the participation of the wholesale group in this process.
I want to make sure I understand your answer. If the wholesale group were not to participate, would we receive a substantial benefit in the sense that we would not be charged with one-third of the regulatory cost?
MR. LARLEE: Just to clarify my previous response, I was looking at historically what had happened in the past in the regulatory proceedings. And is was my understanding that wholesale was a significant participant in those proceedings. So that was the basic rationale.

I don't believe cost allocation studies are used to determine future credits to customers under any conditions. So I can't see that ever happening.

Q.515 - Well let me take it one step further then. If we didn't participate in these proceedings in the future, would it be less than one-third?

MR. LARLEE: I am sorry. Can you repeat the question? I didn't catch the whole thing?

Q.516 - Sure. You were talking about using historical data, rather than projecting this into this hearing and trying to determine whether or not we would be here to participate. So if we didn't participate in this hearing, would that cost go down in the future because we don't participate, would we then go down to about 10 percent, which is what you say based on sales revenue is where we would fit?

MR. LARLEE: Well, I think the real determination on what would happen in the future is what the Board decides as far as the details of the methodology for the cost allocation study. I think we have got to keep everything in perspective here, too, in that these numbers are relatively small to the overall cost. We are looking at numbers all less than a million dollars, so --

Q.517 - But I might remind you that those numbers might be

significant to the clients that I represent?
MR. LARLEE: Oh -- and I didn't mean to imply that. I just wanted to make sure that we keep the perspective and keep it relative.
Q.518 - So as an alternative to the manner in which you have -- the basis on which I guess you have allocated regulatory expenses, would it be consistent with standard a practice to do it on some other basis? For example, sales revenue, would that be a reasonable manner in which to allocate that expense and one that is consistent with practice that you are aware of or familiar with?
MR. LARLEE: I wouldn't be -- it wouldn't be inconsistent. What I was trying to do essentially was to reflect the cost causation as best as possible. But certainly using revenue would reflect what --
Q.519 - If I were to continue down on Addendum 3 under Holdco costs, I would find that there are five separate costs that are dealt with there. And under Basis, four of them talk about sales revenue and again the regulatory is again done on the basis of one-third, one-third, one-third?
MR. LARLEE: Correct.
MR. KETCHUM: And if I might just comment for a moment on that. When looking at general costs and administrative costs, as with several other costs, as you are pointing

out there is an element of judgment involved here. I think what Mr. Larlee has done is one reasonable way of doing this. And admittedly there are others.

Sales revenue being another, but not necessarily a right way and a wrong way. At the end of the day when you add all of these up, there is going to be some give and take on either side of the ledger with respect to the individual elements. But at the end of the day, the administrative costs here are segregated in a way that has allowed Mr. Larlee to make some reasonable judgments about cost causation that he has applied.

Lots of times when we look at some of these things, they are more aggregated and a grosser sort of methodology is applied. For example, as was mentioned here, utilizing of all other costs kind of allocator. So I think this is an attempt to be more precise on the basis of more disaggregated data and I think it's reasonable.

Q.520 - Mr. Ketchum, perhaps I could ask you then how sales revenue would be more precise than total allocated costs? How would that be more precise?

MR. KETCHUM: Because what I am trying to say is here if it's disaggregated to these individual account levels, and you have a sense that it's reasonable to do that particular account on sales revenue that's more precise I would say than a general allocator. Just in that sense that it -- as I said, Mr. Larlee has attempted to look at each of these individual lines and come up with something that he thinks is reasonable.

At the end of the day it seems to me that that could be a better way of doing it than a general allocator.

Q.521 - So are you in a sense I guess saying the same thing that Mr. Larlee is saying is that because of the participation of this group in the hearings that we should be charged with effectively one-third of the cost?

MR. KETCHUM: Well, again I think Mr. Larlee was attempting to look at that particular line item and apply a judgment about what caused a cost. So I think, you know, in that sense that, you know, that is a better way of looking at it than saying, for example, that that particular cost, as opposed to the sum of all the costs, might better be allocated on the basis of this kind of a cost causation estimate if you will or judgment.

Q.522 - Well would you agree with me then that if we did not participate in the hearings, the hearings still would need to go ahead, that the rates would have to be approved? This process would continue with us or without us?

MR. KETCHUM: I think that might very well be true, but I still believe that there would be some representative of your client that would want to participate in one way or another. And there is still a lot of attention paid to the municipal clients in the overall scheme of things in the regulatory area.

Q.523 - Mr. Larlee, I am going to refer you to exhibit A-11. So exhibit A-11, I am referring to the IR-13, Disco UM, IR-13, July 14th 2005.

MR. LARLEE: Would you give me that one more time please?

Q.524 - Sure. It is Disco UM IR 13. That is from the July 14th set of Interrogatories. Do you have that in front of you there?

MR. LARLEE: Yes, I do.

Q.525 - Yes. And then that is a question that deals with what we have just been talking about, regulatory functions listed in addendum 3?

MR. LARLEE: Yes.

Q.526 - Okay. And are there any other -- with respect to the regulatory cost you named a few things that are included in that.

Could you expand upon that? Is that sort of comprehensible? Or are there other elements included in regulatory?

MR. LARLEE: I wouldn't want to venture to say that that is comprehensive. Those are examples of the costs included in regulatory.

Q.527 - Well, you are talking about cost to hearings, administration cost, consultant services. Would it be fair to say legal costs and other costs of that nature?

MR. LARLEE: Yes, I believe so.

Q.528 - And in that response you also indicate that it is being allocated on a one-third basis because of active participation in regulatory proceedings, is that correct?

MR. LARLEE: Yes.

Q.529 - This morning we I guess heard a lot about the Electric Utility Cost Allocation Manual produced by the National Association of Regulatory Utility Commissioners. And you are obviously very familiar with that. That is the manual that you were questioned about this morning quite at length by Mr. MacDougall?

MR. KETCHUM: Yes. We are familiar with that.

Q.530 - I would ask you to turn to that manual. And it is found in exhibit 14 as appendix 7. Do you have that in front of you?

MR. KETCHUM: We have that general item in front of us, yes.

Q.531 - Thank you. I am just going to take you, first of all, just to the preface of that manual which I believe appears about three pages in.

And at the bottom the authors say "We set the

following objectives for the manual. It should be simple enough to be used as a primer on the subject for new employees yet offer enough substance for experienced witnesses. It must be comprehensive yet fit in one volume. And the writing style should be nonjudgmental, nonadvocating any one particular method but trying to include all currently used methods with pros and cons."
Would you agree that that manual meets those objectives?
MR. KETCHUM: Yes. I would agree with that.
Q.532 - And that particular manual, Mr. Ketchum, probably is something that you have referred to in your evidence over the years, as being something that you have relied on?
MR. KETCHUM: Yes. As a general proposition, as you just read, it does contain a lot of different methodologies and different approaches, for example for classifying the fixed cost of generation. It lists a dozen or so methodologies, the peaker credit being one of them.
So certainly I have referred to the manual. And I have quoted it from time to time in my testimony and evidence.
Q.533 - And I have no doubt that you are aware of other experts and have heard them refer to it and rely on it?
MR. KETCHUM: That is correct, sir.

Q.534 - I refer you to chapter 8, page 105. And this chapter deals or describes general plant investments and administrative and general expenses are treated in a cost of service study. Would you agree?

MR. KETCHUM: That is the topic of this chapter. Yes, sir.

Q.535 - Thank you. And the authors state under number 1, "General Plant" that "General plant expenditures" -- and I'm not going to talk about the account numbers -- but "General plant expenses are that portion of the plant that are not included in production, transmission or distribution accounts but which are nonetheless necessary to provide electric service."

Do you agree that that is what it says?

MR. KETCHUM: That is what it says. Yes, sir.

Q.536 - And are those the kinds of things that we are dealing with in addendum number 3?

MR. KETCHUM: Yes, they are.

Q.537 - So if I was to look for some guidance, if you will, as to how to prepare addendum number 3, chapter 8 of this manual should provide me with some guidance?

MR. KETCHUM: I would suggest to you that the starting paragraph here deals with general plant and we are dealing with general costs.

Q.538 - All right. And so what we have been talking about is regulatory. Is that dealt with in here?

MR. KETCHUM: You need to go over and look at expenses, so on the next several pages.

Q.539 - So page 106 under "Administrative and General Expenses", was that where I would find regulatory?

MR. KETCHUM: That is correct. Now, of course, I just might add that this is based on the FERC system of accounts. And these accounts are aggregated.

And some of the pieces that might fall in the Disco accounting system under regulatory may fall in one or two of these categories. For example, it may be an A & G. And it may also appear in outside services as an example.

Q.540 - But I understand that there are account numbers. And in fact they talk about, under part 2, account numbers 920 through 935, is what they are talking about. Is that correct?

MR. KETCHUM: Yes.

Q.541 - And we can get an idea as to what they include in accounts 920 through 935 by looking at the table as produced on page 106 and which continues on to page 107?

MR. KETCHUM: Those -- I would just say if you just read the account titles, it gives you some sort -- sort of a general idea what falls into those accounts.

And the other two columns are a couple of different ways of allocating those costs that have been suggested in here, among other approaches that are possible.

I think this also sort of illustrates the point that I was trying to get at earlier, that Mr. Larlee was looking at more of this aggregated kind of information here, more detailed information.

So he didn't have to apply say an overall general sort of allocator to what might have been under A & G salaries, several sub accounts. He looked at those things in a disaggregated way. So he didn't have to apply an umbrella allocator if you will.

Q.542 - Mr. Ketchum, I am not entirely sure I understood what you were saying. But let me see if I can through questions try to figure out, you know, precisely what you were trying to tell us.

When I look under "Administrative and General Expenses" it says administrative and general expenses include accounts 920 through 935. And that includes account 928, if you look on page 107, which is regulatory commission expenses. And they are allocated with an approach similar to that utilized for general plant.

Would you agree with that?

MR. KETCHUM: 928 is regulatory commission expenses. That is not the same however as the regulatory expense necessarily that is included in Mr. Larlee's regulatory accounts.

Q.543 - Why would the allocator be any different? Because you have looked to allocated on the basis of participation in the hearing process. And quite frankly I see absolutely nothing in that manual that suggests that as a method that would be appropriate.

MR. KETCHUM: I think you will find that this suggests that this is an example of allocation of A & G cost using a three-factor and two-factor approach.

This doesn't say that this is either the right way or the only way. As it said in the preamble, it also indicates that what NARUC is trying to work with here is some of things that they have seen in the past.

So I would say that the fact that the way Mr. Larlee did it doesn't appear here doesn't necessarily mean anything let alone that it is not proper.

Q.544 - Well, you have referred to the preamble in your answer. And would you agree that the preamble says -- on the third bullet on the preamble says that it tries to include all currently used methods with pros and cons?

MR. KETCHUM: It tries to. And by the way it was in 1992. And this is generally something that has been looked at in terms of FERC accounting. So again there are some differences that I think are important distinctions.

I don't think you can take an example from this even though it is not unreasonable necessarily. But you can't take anything from this and say that just because Mr. Larlee's approach doesn't appear here that it is not reasonable.

Q.545 - Mr. Ketchum, were you consulted with respect to this particular allocator prior to this report being prepared, this study?

MR. KETCHUM: Prior to the report -- I'm sorry?

Q.546 - Were you consulted specifically with respect to the one-third regulatory charges being allocated to each of three groups?

MR. KETCHUM: Again, my charge was to review what DIsco had done and provide my opinion as to whether or not it was reasonable. That was my charge. And I did review what Mr. Larlee did and I did say and believe that on an aggregate basis, at least it is very reasonable.

Q.547 - But you keep saying on an aggregate basis. But as a separate item is it reasonable? Is it something you have seen before? And if so, perhaps you could tell us where you have seen it?

MR. KETCHUM: I don't think I have ever seen that way particularly but I think it has been -- I think I can say that in my experience, what Mr. Larlee took into account there in terms of cost causation, that is, which elements in terms of the classes of service were driving regulatory costs, is one element that other rate groups, I believe, have taken into account.

I thought that overall he explained to me how it was done and why and I couldn't say that that was unreasonable.

Q.548 - Would it be consistent with the manner in which he has allocated the other costs?

MR. KETCHUM: That is the whole point, it doesn't need to be consistent. Every account may have different cost drivers and there may be some factors that are more reasonable for one account than they are for another.

If you look at the example, for example here some are allocated on plant, some allocated on salary, some allocated on revenues and that sort of thing in the example. So it depends on what you are talking about and if it seems to be something that makes sense.

Q.549 - Would you agree that in terms of then looking at the hearing process, cost causation variables might include a number of things, such as the number of rates and classes?

MR. KETCHUM: I think in terms of maybe -- I think I know what you are driving at. But in terms of the hearing process, I'm not necessarily sure that I could agree with that. But with respect to regulatory expense, I think one element may be a way of looking at it would be the number of classes, yes.

Q.550 - Okay. And perhaps also the complexity of the costs being scrutinized by the Board? Would that also be a factor?

MR. KETCHUM: It doesn't seem to me that that makes a big difference in terms of -- it may make a difference in terms of the overall cost that Mr. Larlee may have to have in his budget.

For example, he would probably have to have an increased budget if there was a mandate to do full blown marginal cost studies. So certainly if that was an outcome, that would be a driver of regulatory costs. But that doesn't necessarily reflect on how one might split up that particular account.

Q.551 - Mr. Ketchum, you said that one of the strengths of this approach that you are advocating here is the different types of costs are considered separately. But how is that consistent with saying that in aggregate it is reasonable?

MR. KETCHUM: I am sorry. I'm not quite sure I followed your question.

Q.552 - Well I think one of your responses there is you said one of the strengths of this approach is the different types of costs would be considered separately. In other words, the regulatory costs and what not.
But if you are considering them separately, the evidence you have given to date is that we should consider it in the aggregate. So how is it consistent with your statement that it should be considered in the aggregate?
MR. KETCHUM: Yes, sir. I see what you are driving at.
That might have sounded like an inconsistency, but what I meant to say, at the end of the day, if you add up a lot of little pieces and you think those little pieces are done properly, or in a reasonable way, you have a sense that the aggregate then is also reasonable.
And when you look at the aggregate and you look at it compared to in general, you know, the outcome of the allocation of aggregated costs or something more into this example, then you can say well, that's another way I can tell that it's reasonable.
Q.553 - This question I am not sure if it is for Mr. Larlee or Mr. Ketchum. But I think for Mr. Ketchum.
If the Board were to reject your proposal of one-third basis of allocation of these regulatory costs, what method or methods do you think would be reasonable to adopt?

MR. KETCHUM: You are asking me to help you out here.

Q.554 - Sorry, I am asking you to help out the Board.

MR. KETCHUM: Help the Board. I think that again there may be some other ways of doing that and perhaps in aggregate of all of the other distribution costs, the way they are allocated to the classes or something of that sort might be reasonable. Because this is a class -- a cost that applies to everybody.

Q.555 - I just need a minute or two here to change topics. Mr. Larlee, if I can go back to A-3, and I'm going to your evidence, I'm going to take you to page 4 of your evidence. And page 4 is introduced by question 6 which is, what are the results of the 2005/06 CCAS, and then you provide a table which summarizes those results.

MR. LARLEE: That's correct.

Q.556 - And in the first column you have Rate Class as the heading?

MR. LARLEE: Yes, I do.

Q.557 - And in response to questions this morning from Mr. Coon, I think you said there were -- I think you counted them out and said there were eight rate classes?

MR. LARLEE: Yes, that's correct.

Q.558 - And if I can take those rate classes from the bottom to the top, not the overall, but wholesale would be one of those rate classes?

MR. LARLEE: Correct.

Q.559 - And wholesale at this time represents Saint John Energy and the City of Edmundston?

MR. LARLEE: That's correct.

Q.560 - The next group are the large industrial?

MR. LARLEE: Yes.

Q.561 - And what types of industry would be covered by that group, just as an example?

MR. LARLEE: Large industrial is any customer over 750 kilowatts in manufacturing or processing. So it literally includes the very largest processing and manufacturing plants in New Brunswick which are pulp and paper mills to some quite small operations in the food processing and small sawmills, these types of operations.

Q.562 - Okay. And then moving up the table you then list six other rate classes and you -- of course we this morning discovered the residential actually is divided into electric and non-electric but is considered one class, but that was for comparison purposes to show it that way, is that correct?

MR. LARLEE: The residential class for this cost allocation study was segmented and that's why I have shown them indented here in this table.

Q.563 - But it's actually just one rate class as residential?
MR. LARLEE: Exactly. Just one rate class, that's correct.
Q.564 - The other rate classes are General Service I, General Service II, streetlights and unmetered water heaters and small industrial?
MR. LARLEE: Correct.
Q.565 - And wholesale we have -- I guess you have agreed that wholesale for the present time at least would represent Saint John Energy and Edmundston Energy?
MR. LARLEE: That's correct. Those are the only two customers at that rate.
Q.566 - And they would have customers on the retail side, their retail customers, that would fall within categories -- they are not numbered but from the top down categories 1, 2, 3, 4, 5 and 6, is that correct?
MR. LARLEE: Yes, that's my understanding.
Q.567 - So for example Edmundston Energy would have residential customers, General Service I and II customers, small industrial customers?
MR. LARLEE: Correct. Yes.
Q.568 - And Disco as a distribution utility would have the exact same grouping of customers, is that correct? I'm talking about the retail side of Disco.
MR. LARLEE: I would like to clarify that just before I

answer. The rate classes as defined by NB Power aren't defined exactly the same for Saint John Energy in particular. So although the titles of the rate classes may be similar the actual terms and conditions that these customers work under are quite a bit different in the case of Saint John Energy.

The other point I would like to make is although again the rate classes are similar the actual mix and number of customers percentage-wise for Disco and wholesale are quite different.

Q.569 - Okay. So I can take you back to I guess the original question. The six categories -- and let's call them categories within the rate class. Mr. Ketchum is shaking his head. No, I can't call them categories.

MR. SOLLOWS: He called them sub-classes earlier.

Q.570 - Okay. Well the six sub-classes, will that work?

MR. LARLEE: That's fine.

Q.571 - The six sub-classes exist for Disco customers and they exist for Saint John Energy customers, is that correct?

MR. LARLEE: Yes. That's my understanding, yes.

Q.572 - And you just testified that Saint John Energy -- you didn't mention Edmundston Energy, so I will stick with Saint John Energy as the example -- that the sub-classes differ in some way from Disco's sub-classes, did I understand your evidence correctly?

MR. LARLEE: Yes.

Q.573 - Could you elaborate on those differences?

MR. LARLEE: I'm not intimately familiar with Saint John Energy's rate policies and applications but I do know of a couple of significant differences. One is that they have already closed their all-electric rate. So I think that's the significant difference of note. The other is is their non-residential rates have different clauses in them similar to ratchets in the demand charges. They are not exactly ratchets but they are similar to ratchets. So these are significant differences in the rates.

Q.574 - I'm sorry, I didn't catch the last part of that. Could you repeat that, just the last part of your statement?

MR. LARLEE: That these are significant differences --

Q.575 - Just prior to that, the difference you were -- I was listening to my colleague.

MR. LARLEE: Oh, that the non-residential classes have aspects to the rates that are similar to demand ratchets. In other words the customers are required to pay minimum demand charges, whereas in our general service rates we don't have those types of clauses.

Q.576 - But effectively the customers would be the same. The same sub-classes of customers are being served by both, by both Disco on the retail side and by Saint John Energy for example?

MR. LARLEE: Again I'm not intimately aware of their policies but I believe generally it's the same type of customers, and what I will do is I will explain the way NB Power's division works and that is essentially we define whether a customer is residential or industrial. If they don't fit either of those two definitions general service is the default service. So the definition for general service customer is actually what they aren't. They aren't residential and they aren't industrial, industrial meaning manufacturing, processing or mining, and by default they end up general service.

Q.577 - Okay. But again the -- and I don't mean to beat this to death, but the group of customers serviced by Saint John Energy is effectively the same. They have residential customers, so does Disco, they have general service customers, so does Disco, they have small industrial, so does Disco, is that correct?

MR. LARLEE: If Saint John Energy is using the same type of definition I just described, yes.

Q.578 - Now I notice that in your table 1, if I were to take the first six classes, residential, General Service 1, General Service II, streetlights and unmetered water heaters and small industrial, and aggregate the revenue to cost ratios that are proposed, I don't see anything set forth in your evidence that would tell me what the aggregate revenue to cost ratio would be for those services with respect to Disco retail. Have you produced that number?

MR. LARLEE: No, I don't believe -- I know I haven't in the evidence, I don't believe we have through the IR process either.

Q.579 - It wouldn't be part of your -- I haven't seen it in your pre-filed evidence where it has been broken out that way. Well then would you agree that the service that is being provided to these six sub-classes by the wholesale customers is effectively the same service that is being applied by Disco, so it might be useful to compare the aggregate revenue to cost ratio that effectively Disco is paying for the -- with respect to its retail customers?

MR. LARLEE: Well I will start with the first part of your question, and you asked me if I agreed that the service is the same. I don't agree. And even though -- I was trying to allude to earlier is even though the class -- the customers within the classes look the same, the actual make up of the class is -- the relative make up between the wholesale customers and Disco is quite different. Disco has a much higher percentage of industrial customers than the wholesale customers. Disco has a higher percentage of residential customers. And if you think about the wholesale customers and the fact that they are completely urban in their service territory, that makes sense that the commercial type customer which primarily makes up general service tend to be in urban areas. So they have a higher penetration of general service. As well Disco has much more rural service territory. So we have many more rural customers than the wholesale customers do. So we do provide in essence different service than the wholesale customers.

Q.580 - Well, I think what you are describing is what you consider to be a different profile with respect to these classes of customers, but I think you -- at least in my view you have moved off the point I was trying to make that effectively these sub-classes exist in both Saint John Energy for example, Edmundston Energy and in Disco.

MR. LARLEE: I mean, that's correct. I agree with you there. But you were beginning to talk about the cost allocated to each of these classes and we can't talk about how the costs are allocated to the classes unless we talk about how these classes are made up and the differences in how they are made up.

Q.581 - Okay. But I guess just to -- and maybe I will get off of this particular point. The six essential sub-classes exist for both?

MR. LARLEE: Yes.

Q.582 - Now I understand that the second part of your answer was that maybe the profile of these customers might be a little different in Edmundston than it is in Nackawic, it might be different in Saint John than it is say in Sussex?

MR. LARLEE: My point was is that it's significantly different between Disco and the wholesale customers.

Q.583 - Okay. And within Disco if you were to go to different communities or different areas you would find that it's different within Disco as well depending on the area you were looking at, the profile to make up the percentage of each sub-class, and I think that's what you are telling me?

MR. LARLEE: In any rate class there is going to be a lot of variability within the rate class, yes, that's correct.

Q.584 - Okay. Perhaps I could ask you to look at the schedules which are attached to your evidence. That's still in A-3. And the first schedule I am going to ask you to look at is schedule 6.0. And I am also going to refer to UM-1. Sorry UM-1.

MR. MORRISON: Exhibit number?

Q.585 - Exhibit UM-1. That is the pre-filed evidence of Paula Zarnett. And in Ms. Zarnett's evidence, if you would turn to table 5 -- do you have table 5 in front of you?

MR. LARLEE: I do, yes.

Q.586 - Does everybody on the Board have that now? I am going to compare a number of -- sorry. Everybody have it? Thank you. I am going to ask you to compare the numbers from some of your schedules to the entries that appear on table 5 in Ms. Zarnett's evidence.

That table 5 is entitled "Comparison of revenue cost ratios by customer class as proposed by Disco". And the first column -- sorry, the first column that appears is entitled "Fully allocated revenue". Do you see that?

MR. LARLEE: Yes, I do.

Q.587 - And it says schedule 6.0. Do you see that just above where it says "Fully allocated revenues"?

MR. LARLEE: Yes.

Q.588 - Okay. Now I want you to compare and you may well have already done this. But I would like you to compare the entries on table 5 with the entries on schedule 6.0 on the last column, "fully allocated revenue". And a couple of them are out of order. They are not -- they weren't reproduced, I don't think, in exactly the same order, which unfortunately may make it a little confusing.

But for example, the first entry that appears under column 5 is $352,476. Do you see that?

MR. LARLEE: Yes, I see that.

Q.589 - In schedule 6. And that number also appears as the first number on table 5.

MR. LARLEE: Yes, I see that. I have just been looking down through the numbers and they appear to be correct.

Q.590 - So you take no issue that the numbers under "fully allocated revenue" in fact were drawn from your schedule?

MR. LARLEE: It certainly appears that way.

Q.591 - Okay. Now would you turn to schedule 6.1. This is NB Power Distribution and Customer Service Class Cost Allocation Study Supply Cost Allocation.

MR. LARLEE: Yes.

Q.592 - And again I am going to ask you to go to column 7, supply cost total, and to look under the column on table 5 entitled "Schedule 6.1 Total Supply Cost" and verify that the numbers that have been used in fact have been taken from your tables?

MR. LARLEE: Total Supply Cost is under column 2 in 6.1?

Q.593 - Yes. The second column, yes. It's the last column -- sorry. If I said 6.1, I should have said 5.1. So I direct you to schedule 5.1.

MR. LARLEE: Again the numbers appear to be drawn from either column 5.1 or column 2 of 6.1. The numbers are the same.

Q.594 - Thank you. The third column is entitled schedule 5.2 "Transmission Service Cost", and if you go to your schedule 5.2 would you verify that those are your numbers as well?

MR. LARLEE: Again they appear to be drawn from that schedule.

Q.595 - And finally there would be schedule 4.5 dealing with distribution and revenue requirement. And I would ask you to look at column 11 in schedule 4.5 and compare it to the fourth column?

MR. TINGLEY: Where are we now?

MR. GORMAN: We are on schedule 4.5 attached to Mr. Larlee's evidence. I know sometimes we need a road map. So Mr. Larlee, then I guess I will ask you to compare the entries in column 11 of schedule 4.5 with the fourth column in table 5.

MR. LARLEE: Again the numbers appear to be drawn from schedule 4.5.

Q.596 - So you would agree then that the -- first of all, that the numbers that have been inserted into table 5 have all originated with your pre-filed evidence?

MR. LARLEE: It certainly appears that way to me.

Q.597 - And you will see that we have a heading on the left hand side that says "NBP Distribution Customers", and you will see a number of categories, sub-classes of customers. Again these came from your schedules.

MR. LARLEE: Yes, I see that.

Q.598 - And they would effectively represent the retail customers if you will that NBP Distribution services?

MR. LARLEE: Yes. I would characterize them as customers which we provide distribution services to, yes.

Q.599 - Okay. Now on the far right hand corner of table 5 I guess we have done something that wasn't in your evidence. I would like you to have a look at it. And it says computed revenue cost ratio. And at the bottom -- at the bottom, total NBP Distribution, and if you look on the far right hand column you will see number 1.015.

MR. LARLEE: Yes, I see that.

Q.600 - And you agree that in computing that number that it was your numbers that were used, and do you agree that that is the correct revenue cost ratio, or do you want to take a minute and use your calculator and verify that?

MR. LARLEE: It looks to me like the math is right there.

Q.601 - Okay. So then you would agree that if we were to look at NB Disco in terms of its retail customers and look at what revenue cost ratio was assigned to it, it in fact would be 1.015?

MR. LARLEE: For that particular sub-grouping, let's call it, of Disco's customers, yes, that appears to be the case.

Q.602 - Okay. But that sub-grouping -- and correct me if I am wrong. I understand that sub-grouping effectively is the same types of customers that are served by the municipal utilities, so that we are talking about the same sub-grouping, aren't we?

MR. LARLEE: We are talking about the same types of customers but we are not talking about the same load or the same -- necessarily the same cost causation that wholesale customers would see.

Q.603 - Perhaps you have something further to add along the way, but in terms of the question that has been posed to you, if you were to calculate the revenue cost ratio for the same -- effectively the same set of customers, Disco's comes out at 1.015, you would agree with that? You have agreed with the math.

MR. LARLEE: Yes, I have.

Q.604 - And if I look at the revenue to cost ratio that would be attributed to the wholesale group under the proposal, and I need just to go to table 1, that's exhibit 3, page 4 of your direct evidence.

MR. LARLEE: I have that.

Q.605 - You have that in front of you. Okay. So for the wholesale class, the revenue to cost at proposed rates, at least at the time that the initial application was filed, was 1.05?

MR. LARLEE: That's correct, yes.

Q.606 - And that would be significantly more than what would be assigned to the same group of sub-classes of customers for Disco?

MR. LARLEE: The revenue to cost ratios of that sub-class and wholesale are different, right.

Q.607 - And which is the greater?

MR. LARLEE: Pardon.

Q.608 - Which is the greater?

MR. LARLEE: The wholesale classes at 1.05 and by your calculation all of the distribution served customers of Disco is 1.015.

Q.609 - Okay. So that would make the wholesale greater?

MR. LARLEE: That's correct.

Q.610 - By how much?

MR. LARLEE: By .035 by my quick subtraction.

Q.611 - You don't need a calculator for that one.

MR. LARLEE: No.

Q.612 - So if we have in the province effectively three distributors and Perth-Andover also is a distributor but of course they obtain their power elsewhere, then you would agree that what we have is a revenue to cost ratio assigned to two of those three that is significantly greater than the third?

MR. LARLEE: The revenue to cost ratio for the wholesale class is targeted at 1.05. And the reason for that is because of the contracts that Disco has with the wholesale customers, with the City of Edmundston and with Saint John Energy. Those contracts were put in place back in 1996 and there are clauses in those contracts which bound NB Power and now Disco, to reduce the revenue cost ratio from what it was at the time down to 1.05, and to hold it there.

Q.613 - So effectively what you are saying is because of contracts that are in existence, that 1.05 was predetermined as where they were going to get to and everything else was worked out to make sure that it hit at 1.05?

MR. LARLEE: The proposed rates were set such that it came out to 1.05.

Q.614 - Okay. But I understood your evidence effectively to say that because of contracts with -- and these contracts were originally signed with NB Power when it was an integrated utility, I think you would agree with that?

A. Yes.

Q.615 - And you are saying that you set it at 1.05 because those contracts contained a commitment, as I understand your evidence, and correct me if I am wrong -- a commitment to reduce the revenue to cost ratio from I believe it was quite a bit higher than 1.05 and there was a commitment based on the earlier Board decision which we have heard a lot about, but there was a commitment to reduce it down to the 1.05 level, is that --

MR. LARLEE: Correct.

Q.616 - And that was reflected in the contracts?

MR. LARLEE: Correct.

Q.617 - Now the contracts -- I guess that part of the contract which deals with the 1.05, the background for that is the 1992 decision. Would you agree with that?

MR. LARLEE: Yes, I would.

Q.618 - And in the 1992 decision -- and again I am paraphrasing, we can go to the decision, I'm sure that a lot of people will jump on me if I'm wrong here -- but the directive of the Board was that effectively over a period of time the revenue to cost ratios for all classes had to be bought within .95 to 1.05. Is that correct?

MR. LARLEE: Yes.

Q.619 - So in order to I guess effectively meet the requirements of the Public Utilities Board, it was essential to get it down to 1.05, but there is no prohibition from getting it down for example to 1.015.

MR. LARLEE: It was explained to me that those contracts were written such that the revenue cost ratio was to be held at 1.05.

MR. MORRISON: And, Mr. Chairman, rather than have Mr. Larlee comment on the contracts, I'm sure they will be scrutinized as evidence at some point in this proceeding, and they will speak for themselves I'm sure.

CHAIRMAN: Well, Mr. Morrison, why not sooner rather than later? You have both got them, I presume.

MR. GORMAN: Actually they are in evidence.

CHAIRMAN: All right.

MR. GORMAN: If I could just have a minute to find out where.

CHAIRMAN: Okay. I think we talked about that in Fredericton, didn't we?

MR. GORMAN: The reference is in exhibit A-15, at Appendix number 10. And that's the contract between the New Brunswick Power Corporation and the City of Saint John.

And I believe -- yes, Appendix number 11 is the agreement for the supply of power and energy between New Brunswick Power Corporation and the City of Edmundston.
So if I could ask you to refer to page 3 of that contract. And maybe before I do that, you -- in your answer I think you said you were advised. And I certainly don't want you to disclose any legal advice that you have received. Perhaps that's privileged. But when you say you were advised, I took it that you didn't research this yourself or you had not looked at it previously, because your response was I have been advised that it is in the contracts. Can you elaborate on that for me?
MR. LARLEE: Well, I am not a lawyer. So I didn't rely on my own skills to interpret the contract. I relied on others within the company.
Q.620 - Effectively some legal advice is that what you are telling me that you got legal advice as to what that meant?
MR. LARLEE: Ultimately, yes.
Q.621 - If we can then refer to page 3 on that contract. And let's go back for a moment to the context in which the 1992 decision was rendered. And as I understand it again, and I will paraphrase it that the Board directed the parties to -- sorry, directed NB Power to get the revenue

to cost ratios for all classes within this .95 to 1.05 band if you would. You would agree with that?
MR. LARLEE: Yes.
Q.622 - And there certainly would be no prohibition from this, as we have talked about within the decision itself, let's leave the contract alone for a moment, to being less than 1.05, that would in fact be in a perfect world, everybody would be at 1?
MR. LARLEE: No, there certainly is no prohibition to any rate class. And then there is no different -- there is no specific direction in the Board's decision on any particular rate class. It's strictly all rate classes within the range is my recollection.
Q.623 - Sure. And still maybe sticking with the 1992 decision, and the Board, you know, said in the long term certain things were to happen. I guess I can't speak for the Board, but I would have to say that between -- I think the hearing was in 1991 and, you know, I guess we have gotten into another century. So I think that's perhaps what one might consider to be -- there has been quite a long term. I don't know what the Board had in mind when they said long term, but it strikes me it's a long time since that decision.
CHAIRMAN: Didn't you sit, Mr. Gorman?

MR. GORMAN: I wouldn't be asking questions on it if I had.

Q.624 - So if we now go to page 3 of the contract, the Saint John Energy contract, that's Appendix 10. Revenue to cost ratio rate adjustment, 3.3, is that what you are talking about where you say it's in the contract?

MR. LARLEE: There is -- I believe there is this section and then you move ahead to Appendix A. There is no page number on it. It's after the signatory page. There is Appendix A. There is actual dates in the adjustment. So those -- that section in that Appendix I believe are -- make up the requirement to move the revenue to cost ratio.

Q.625 - Now let's talk about the contract generally first then. My understanding is that the contract term expires sometime early next year?

MR. MORRISON: I think that's found at page 6 under paragraph 3, Mr. Chairman.

MR. LARLEE: Yes, that's what's written on page 6, paragraph 3.

Q.626 - So even if the contract were binding on Saint John Energy despite what might come out of these hearings, it would only be binding until the end of March next year, would you agree with that, based on this contract? I am not asking you to give me a legal opinion, but on the face of it, isn't that what it appears to say?

MR. LARLEE: Well, I hate to read contracts without the help of legal advice. But it does go on to say if we read 3, Article 8 of the supply agreement entitled, Term Agreements Hereby Amended, extend the term of the agreement to March 31st '06, and thereafter year to year and until one of the parties hereto gives 12 months notice of its intention to terminate. And so unless someone has given notice, I assume the contract would continue.

Q.627 - So the parties though under the agreement can give notice to terminate it, is that correct? I mean that's what you have just read?

MR. LARLEE: I mean that's what my layman's understanding, yes.

Q.628 - Now let's look at the Section 3.3, which deals with the Revenue to Cost Ratio Rate Adjustment. And I going to ask you to read for the record that first full paragraph begins, In consideration?

MR. LARLEE: In consideration of the City agreeing to take electric power and energy solely from NB Power during the term of the Agreement, NB Power agrees to apply a revenue to cost ratio rate adjustment ("Rate Adjustment") to the monthly bills otherwise payable by the City such that the effect of the Rate Adjustment will be the reduction, over the first 5 years of this Agreement, of the revenue to cost ratio for service to the City from 114 percent (being the revenue to cost ratio calculated by NB Power for Wholesale customers for NB Power's fiscal year '95, '96) to 105 percent, and the maintenance of the revenue to cost ratio to no more than 105 percent until termination of this Agreement. The Rate Adjustment shall be applied as follows.

Q.629 - Thank you. I am going to direct you to the second last line in what you have just read, which I guess if we start from the third last line, it directs it to get down to 105 percent by 1995, '96, you would agree with that? That that's what's agreed by the parties?

MR. LARLEE: Yes.

Q.630 - And after that it doesn't say that it is to be maintained at 105 percent does it?

MR. LARLEE: What it says is, and the maintenance of the ratio at no more than 105 percent.

Q.631 - And I appreciate that you are not a lawyer, but would it be fair to say that at no more -- that 102 would be acceptable -- 102 is no more than?

MR. LARLEE: That is correct. However, you have to read that in the context of Appendix A.

Q.632 - Okay.

MR. LARLEE: If you go down to the bottom of Appendix A, there is a specific formula for the April 1, 2000 adjustment.

CHAIRMAN: Mr. Gorman, I hate to interrupt, but is this not a legal argument?

MR. GORMAN: Well, it wasn't my intention to bring this forward, but I guess it just came up as part of the response by this witness as to why -- I am not sure, quite frankly, if I can go back to his response, whether it was the reason that they were at 105 or one of the reasons. But this -- I guess this particular document has been brought forward. Really I thought the Board wanted to look at it because the witness had referred to it.

CHAIRMAN: Oh, no. I do. But what we are getting down now is the interpretation of that contract and I would suggest that's something that you gentlemen can handle quite ably in summation.

MR. GORMAN: It's a hard temptation though not to.

CHAIRMAN: I know. And it just crossed my mind that if Saint John Energy were to terminate this contract does that mean that they no longer get standard service?

MR. GORMAN: Yes.

MR. MORRISON: There could be all kinds of ramifications when this contract --

CHAIRMAN: Okay. Sorry.

MR. GORMAN: Nobody should interpret what this questioning to mean that there is any indication of termination of the contract in the near future. There is a -- I am not aware of any options quite frankly.

MR. MORRISON: Has Mr. Gorman given notice -- giving notice, Mr. Chairman?

MR. GORMAN: I think it says it has to be written notice. In any event, I won't ask any further questions on the contract itself. I think that we have made our point that the contract does allow for something less than 105 percent.

Q.633 - So, Mr. Larlee, if I can perhaps go back to your response to a few questions ago and your answer as to why the wholesale class was at 105 percent and you said well it's because it's in the contract. So for argument sake, let's consider the fact that perhaps we do have our legal arguments and that the wholesale class wins the day and the Board accepts the fact that they are not bound by 105 percent, but that it could be less. Do you have any other reason why the wholesale class is at 105 percent?

MR. LARLEE: Well under your hypothetical scenario, we would do as we would do with all rate adjustments look at the rate objectives of -- that we are using at the time and adjust the rates accordingly.

Q.634 - Well then let me phrase that a little bit differently. In putting together your study, did you consider that 105 for wholesale was set in stone? That you should just go there because of the contracts and for no other reason that you have given any consideration to?

MR. LARLEE: I considered it set in a contract.

Q.635 - So you didn't consider anything else?

MR. LARLEE: No, I didn't for this particular rate proposal.

MR. GORMAN: Mr. Chairman, I see that it is 10 to 3:00 and although I probably have some more questions for these individuals, I think the next group of questions I intended to ask would more suitably be questions for Mr. Marois. And I know that I guess what we were told at the beginning of this process, was that we would try to break as close to 3:00. I wonder if this would be a good time to do that?

CHAIRMAN: All right. And I understand counsel of the parties are going to meet anyway to talk about what will unfold for tomorrow. We will rise then and reconvene tomorrow morning at quarter after 9:00.

(Adjourned)

Certified to be a true transcript of the proceedings of this hearing as recorded by me, to the best of my ability.

Reporter