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

Algonquin Hotel, St. Andrews, N.B.
October 26th 2005

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CHAIRMAN: Good morning, ladies and gentlemen. This is a continuation of the NB Power Disco application for changes in its rates and tolls. And could I have appearances, please, for the Applicant?

MR. MORRISON: Good morning, Mr. Chairman, Commissioners. For the Applicant, Terry Morrison, David Hashey. And with us is Lori Clark and Roch Marois and Neil Larlee and

Malcolm Ketchum.

CHAIRMAN: And Canadian Manufacturers & Exporters, New Brunswick Division? Eastern Wind? Enbridge Gas New Brunswick?

MR. MACDOUGALL: Good morning, Mr. Chair, Commissioners. David MacDougall on behalf of Enbridge Gas New Brunswick. I will be joined shortly by Miss Shelley Black and Mr. John Thompson of Enbridge, who are coming down this morning. And today our witness is Dr. Alan Rosenberg, who is over to the left.

CHAIRMAN: Thank you, Mr. MacDougall. The Irving Group of Companies? Jolly Farmer? Rogers?

MS. VAILLANCOURT: Good morning. Christiane Vaillancourt representing Rogers.

CHAIRMAN: Thank you. Self-represented individuals? Municipal Utilities?

MR. GORMAN: Good morning, Mr. Chairman and Commissioners. Raymond Gorman appearing for the Municipal Utilities. This morning I have with me Eric Marr, Dana Young, and Jeff Garrett.

CHAIRMAN: Thanks, Mr. Gorman. Vibrant Communities? And the Public Intervenor?

MR. HYSLOP: Thank you, Mr. Chairman. Peter Hyslop with Mr. Knecht, Mr. O'Rourke, Mr. Barnett, Ms. Young and Ms.

Power. Thank you.

CHAIRMAN: Thank you. And Mr. MacNutt, who is with Board counsel today?

MR. MACNUTT: I have with me Doug Goss, Senior Advisor, John Murphy, Advisor, John Lawton, Consultant, and Arthur Adelberg, Consultant.

CHAIRMAN: Thank you, Mr. MacNutt. And Informal Intervenors today who just want to go on the record? If not, go to preliminary matters. First off, the Board will be delivering a ruling in reference to the motion concerning Board jurisdiction to set a rate for pole attachments tomorrow afternoon.

And we have some exhibits, Mr. Morrison, that we should be marking now?

MR. MORRISON: That is correct, Mr. Chairman. It is undertaking responses.

CHAIRMAN: Okay. Do you want to go that way first?

MR. MORRISON: I believe copies have been provided to the Secretary. The first is an undertaking which is undertaking number 1 from Wednesday, October 5th.

CHAIRMAN: My records indicate that should be A-41. And how did you characterize that, Mr. Morrison?

MR. MORRISON: That is the undertaking number 3 from Wednesday, October 5th. Sorry, undertaking number 1 from

Wednesday, October 5th.

CHAIRMAN: Okay. Thank you.

MR. MORRISON: The next item, Mr. Chairman, is undertaking number 3 from Wednesday, October 5th.

CHAIRMAN: So that will be A-42.

MR. MORRISON: And the next item, Mr. Chairman, is undertaking number 1 from Thursday, October 6th.

CHAIRMAN: A-43.

MR. MORRISON: The next -- give the Secretary a chance to catch her breath here. The next item is undertaking number 2 from Thursday, October 6th.

CHAIRMAN: A-44. Is that from October 5th?

MR. MORRISON: That was October 6th, undertaking number 2 from October 6th.

CHAIRMAN: On the actual response, Mr. Morrison, it has requested October 6th 2005.

MR. MORRISON: That is correct.

CHAIRMAN: Sorry. I am transposing figures here. Carry on.

MR. MACNUTT: Just so we can catch up, Mr. Chairman, what are we marking now?

MR. MORRISON: Undertaking number 2 from October 6th 2005.

CHAIRMAN: And it is A-44, Mr. MacNutt.

MR. MACNUTT: They are just being handed out now, Mr. Chairman.

MR. MORRISON: I will slow down. And finally, Mr. Chairman, it is undertaking number 3 from Thursday, October 6th 2005.

CHAIRMAN: A-45.

MR. MORRISON: And our records indicate that there is only one outstanding undertaking, Mr. Chairman, that we are continuing to work on and that deals with the export data that was provided to the National Energy Board. And we have staff working on that response as we speak.

CHAIRMAN: Any estimate of when that might be available, Mr. Morrison?

MR. MORRISON: We think in the next couple of days but certainly by early next week.

CHAIRMAN: Good. Thank you.

MR. MORRISON: And I have one other preliminary matter, Mr. Chairman.

CHAIRMAN: Yes, what about you filed the evidence -- I will rephrase that. Have we marked as exhibits the refiled evidence on the rate hearing?

MR. MORRISON: The revenue requirement evidence?

CHAIRMAN: Yes.

MR. MORRISON: No, we haven't.

CHAIRMAN: And that has been filed with the Board, has it not?

MR. MORRISON: Yes.

CHAIRMAN: So would this be a good time to allocate a exhibit number to that?

MR. MORRISON: Certainly.

CHAIRMAN: How many volumes are there?

MR. MORRISON: I believe there is just one volume.

CHAIRMAN: Why don't we make it easy and call it A-50. Just nice and easy.

MR. MORRISON: Okay.

CHAIRMAN: So that would be the one volume. And more detail I can just put on that? Evidence, one volume. When was it filed, Mr. Morrison?

MR. MORRISON: It is entitled "Evidence Revenue Requirement", it is volume 1 of 1 and it is dated October 17th.

CHAIRMAN: Thank you.

MR. MORRISON: That is when it was filed.

CHAIRMAN: All right. Thank you. That is really in two volumes, isn't it? It is in two separate volumes in the French and English languages.

MR. MORRISON: That is correct.

CHAIRMAN: So I have marked those two volumes separately but both with A-50.

MR. MORRISON: Fine, Mr. Chairman.

MR. MACNUTT: Mr. Chairman, so we have not marked an exhibit today namely A-46, A-47, A-48, or A-49?

CHAIRMAN: Exactly.

MR. MACNUTT: Thank you.

CHAIRMAN: That's -- for someone as old as I, it will be easier if you say exhibit 50, I know that means the evidence.

MR. MACNUTT: Thank you, Mr. Chairman.

MR. MORRISON: There was one other document filed with the evidence at that time, Mr. Chairman, which was the updated LaCapra report.

CHAIRMAN: Okay. I will work backwards. That will be A-49.

Any other preliminary matters, Mr. Morrison?

MR. MORRISON: Just one, Mr. Chairman. On October 6th, and it is found at page 1460 of the transcript, and I don't think there is any need to turn it up, Mr. Larlee was asked by Mr. MacNutt whether there was data available for total system distribution voltage, industrial customer and transmission voltage. And Mr. Larlee said subject to check, that he didn't believe that that data was available.

He did misspeak. There isn't data available for transmission voltage, but in response to an IR, which was Disco PI IR-4, which was found in exhibit -- I don't have

the exhibit number right offhand, Mr. Chairman, but I will provide it to you -- the response, there was data available for total system and for transmission voltage. But the distribution voltage is not available. So Mr. Larlee misspoke and that evidence is on the record.

CHAIRMAN: Thanks, Mr. Morrison. Any other preliminary matters from Intervenors? Okay, I guess Madam Secretary, swear the witness?

DR. ALAN ROSENBERG, sworn:

DIRECT EXAMINATION BY MR. MACDOUGALL:

MR. MACDOUGALL: Thank you, Mr. Chair. Good morning, Mr. Chair, Commissioners. One small tidy up matter just so that we don't have any confusion going forward. When Dr. Rosenberg's evidence was first submitted to the Board and sent to parties, there were two versions that went in, a confidential version and a redacted version. NB Power later reviewed the confidential version and confirmed to all parties and the Board that there was nothing of confidence -- no concern with confidential information in that document. So the one document that I believe all parties have is a document that says "confidential" on the front, in fact that document is not confidential and none of these matters will be in confidence and we should all be referring to the one single document.

And NB Power did advise everyone about that shortly after the document was filed.

CHAIRMAN: Thanks, Mr. MacDougall.

CHAIRMAN: And Mr. Chair, if I may before I get Dr. Rosenberg to confirm his evidence, his evidence is at EGNB exhibit 1. His qualifications are at appendix A. I understand that no other parties have any concerns with Dr. Rosenberg's qualifications. And if we could have him confirmed as an expert in the areas of cost of service and rate design in the electricity industry?

CHAIRMAN: Okay. It is done.

MR. MACDOUGALL: Thank you.

Q.1 - Dr. Rosenberg, do you have in front of you exhibit EGNB-1, Evidence of Alan Rosenberg on behalf of Enbridge Gas New Brunswick?

A. I do.

Q.2 - And do you also have in front of you, EGNB-2, Interrogatory responses dated September 23rd 2005 to interrogatories submitted on the evidence of Alan Rosenberg?

MR. MACDOUGALL: I think you have to put your mike on, Dr. Rosenberg.

A. I apologize. Yes, there --

MR. MACNUTT: Mr. Chairman, just while we are making those

technical adjustments, I just wish to identify that David Plante of CME has arrived. It might be noted for the record.

MR. MACDOUGALL: Mr. Chair, as now as you will note, Ms. Black and Mr. Thompson have also now joined me.

Q.3 - So, Dr. Rosenberg, just to get that back on the transcript, maybe we can go over that again. You have in front of you EGNB-1, evidence of Alan Rosenberg?

A. Correct.

Q.4 - And you have EGNB-2, which is a binder that contains various sets of interrogatory responses but they were all filed as a single binder, EGNB-2?

A. Yes, I do.

Q.5 - And with respect to both the evidence and the information requests, were those prepared by you or under your direction and control?

A. Yes, they were.

Q.6 - And do you adopt them as your testimony in this proceeding?

A. Yes, I do. The evidence is mine. The tie is Mr. MacDougall's. So if you don't like the evidence you blame me. If you don't like the tie, you can blame Mr. MacDougall.

MR. MACDOUGALL: So Mr. Chair, I believe the two documents

that are important for you to have in hand are EGNB-1 and EGNB-2 until such time as Dr. Rosenberg is available for cross examination.

And as Dr. Rosenberg states, he made it here despite the storm last night, but his luggage did not so the tie doesn't match the shirt perfectly but it was as good as the lawyer and an expert can do, neither with tremendous fashion sense. I will speak for myself. Maybe Dr. Rosenberg has better fashion sense than I.

Mr. Chair, if I may, I am going to take Dr. Rosenberg through a direct examination that is going to cover -- that is going to cover a couple of issues.

Just a few questions just on the background to the preparation of Dr. Rosenberg's evidence. We are then going to go through the three main issues that Dr. Rosenberg raises in his evidence. And along the way, he will make a couple of comments with respect to the evidence of the other expert witnesses filed in this proceeding.

We understood that was the appropriate approach.

CHAIRMAN: Mr. MacDougall, one of the reasons that we have got this commotion going up here is that we all seem to have the redacted but not the unredacted. So the only thing I would request if any time in your examination that

you come upon a page that has in ours redacted, you fill it in for us. Okay?

MR. MACDOUGALL: I will try to do that, Mr. Chair.

CHAIRMAN: I doubt that there is any great problem with this but anyway, we will keep that in mind.

MR. MACDOUGALL: There were very few items, Mr. Chair. I have the confidential version in front of me, so if there is a reference and you see the word "redacted", you tell me and I will fill in where it is.

CHAIRMAN: Absolutely.

MR. MACDOUGALL: Thank you. And I apologize for that. They both were filed with the Board and I thought that had been dealt with.

CHAIRMAN: No, I think it got lost in our shuffle.

MR. MACDOUGALL: Thank you, Mr. Chair. Just to reiterate then quickly, in our direct this morning, Mr. Chair, we will just go through three areas, the first area just being a little background to the approach Dr. Rosenberg took in his evidence to a summary of the various key positions he has taken with a little focus on the cost of service evidence in that it's a little more complex. And three, he will make some remarks on the testimony filed by the other experts in this proceeding as there was no rebuttal period and the parties had agreed in one of

the earlier preliminary conferences that they could comment on each other's testimony in a brief fashion and Mr. Ketchum likewise had done that.

So if I may, Mr. Chair, I will just start with a direct examination of Dr. Rosenberg and after which he will be available for cross examination.

CHAIRMAN: Please do.

Q.7 - Dr. Rosenberg, could you please state the major topics that you dealt with in your direct evidence?

A. Yes. There are three major topics in my evidence. The first deals with the cost of service study, the allocated class cost of service study. The second deals with rate design, specifically rate design for the residential class and for the two general service classes, general service I and general service II. And the third topic addresses the need for a specific rate for customers with their own generation, co-generation, on site generation, who require standby service. And I explained why that is necessary and what the features of such a rate should contain.

Q.8 - Now starting with cost of service, could you explain to the Board what has generally guided your views on the cost of service study that you have proposed?

A. What is generally -- what has guided my views on cost

of service, first of all my personal experience. I have been doing this for almost 24 years in over 20 states and provinces. And I have examined many many cost of service studies, conducted many cost of service studies. So obviously I relied on my own experience.

Second, I relied on standard reference works on cost of service such as the NARUC manual, which I believe has been mentioned in this proceeding.

Third, of course I was guided by the Board's 1992 decision on cost of service. And finally, I was guided by the Reed analysis of 1993.

Q.9 - And were there any threshold questions that needed to be addressed when you considered the cost of service studies supplied by Disco?

A. Yes, Mr. MacDougall. In looking at the allocation and production costs, where I have concentrated my efforts, focused my efforts, there is a threshold question. And the threshold question is do we go on a cost accounting basis? In other words, do we just look at how the Disco gets billed by the PPAs and look no further? Or do we look at a cost causation basis?

And if NARUC defines cost causation as trying to determine what or who causes the costs to NB Power. So that was the threshold question.

Q.10 - And in preparing your evidence, did you have any concerns with Disco's approach to this threshold question?

A. Yes, I did. In all candour, I found Disco's approach to be somewhat ambiguous. For example, on the Genco PPAs they took an accounting approach. They just looked at the accounting situation. And that predominated their views. Whereas when they looked at the Nuclearco PPA, they really decided to look behind the PPA and look at the actual costs of the Point Lepreau.

Q.11 - And which approach did you take to the threshold question on cost of service?

A. I come down four square in favor of the cost causation approach. I think that -- here Is where I differ from Mr. Ketchum. I think the cost causation approach is still very much appropriate. As a matter of fact, it may even be more appropriate in these times of high energy costs. So in the words of -- if I can borrow a phrase from Mr. Adelberg and Mr. Garwood, I am trying to look through the PPA's at the underlying costs and try to establish a cause and effect relationship between the customer's behaviour and the actual costs of New Brunswick Power.

Q.12 - And could you advise the Board why you specifically recommended the cost causation approach?

A. Yes. I think there are eight -- basically eight reasons why I think the cost causation approach is preferable.

Number one, NB Power is an unbundled utility in name only. In other words, it looks like a vertically integrated utility. It acts like a vertically integrated utility. You know, looks like a duck, walks like a duck, quacks, I think it's for all intents and purposes a vertically integrated utility despite the restructuring. At least at this time.

Secondly, the PPAs ultimately must reflect the economic realities of the generation. So you know, why pretend that it -- that it doesn't. Certainly those PPAs were not a result of any competitive bidding process.

Third, I frankly do not see authentic competition -- electric -- when I say competition, I mean on electric competition. Where customers have a choice as to which electric supplier they use. I don't see that coming to New Brunswick for quite some time. So that is the third reason.

The fourth reason is that even if down the road, we do get electric competition and we do have let's say a regulated standard offer service that customers can choose either that or they can go out and get their own supplier.

That would not negate the need for a cost base standard offer service.

The fifth reason is that in New Brunswick we could have gas on electric competition. Maybe not everywhere, but certainly a lot of places you could have gas on electric competition. You can certainly have demand side management on electric competition. And you can't have authentic competition if you don't have a level playing field. And you can't have a level playing field unless NB Power's rates are based on actual costs.

The fifth reason -- I'm sorry, the sixth reason why I come down in favor of a cost causation approach is that you do have this 60/40 approach. You know 60 percent energy, 40 percent demand. Plus that harkens back to the 1992 decision.

That was based on system planning so -- and cost causation. So if we throw out cost causation, in my view you have to throw out the 1992 decision. Because the whole basis of the 1992 decision was on cost causation.

The next reason is if you don't base your cost of service on cost causation, then the customers are never going to get appropriate price signals about how their behaviour and decisions impact the cost of NB Power.

And I guess the last reason I come down in favor of

cost causation on this threshold question is that even if you were to say for the sake of argument, well let's use the cost accounting approach, I think the results would still be ambiguous. In other words, you would still have decisions to make.

For example, on the Nuclearco contract, that is billed to the Disco on the basis of energy. So you might say, well it is energy related. But if you look at it more closely, a lot of that energy -- most of that energy, in fact, almost all is take or pay. So it is fixed.

So in other words, the bill from the Nuclearco company is not going to be impacted whether somebody uses more energy or less energy. It is still going to be the same bill.

So if it is fixed, then traditional cost analysis would say it should be demand related and not energy related.

So for all those reasons, I come down in favor of the cost causation approach.

Q.13 - At this time then, Dr. Rosenberg, could you give us any comments you may have on the approach taken to this threshold question by the other expert witnesses?

A. Looking at Mr. Knecht's testimony -- and I hope I am pronouncing his name correctly -- the -- he calls it the traditional approach, the cost causation approach, the

traditional approach. And my reading is that he does favor that. He does note that the PPAs are not determined by market forces and he also does not consider the PPA approach or the cost accounting approach a particularly stable one over the long run.

In looking at the testimony of Mr. Adelberg and Garwood, on the one hand they say relying on the bill cost is reasonable -- in other words, the cost accounting approach is reasonable. But they also support the Peaker Credit Method. And in my view, that is an inconsistency because the two have nothing to do with each other. The cost accounting approach has nothing to do with the Peaker Credit Method and the Peaker Credit Method has nothing to do with the PPAs. So they do note the inconsistency, however, of Disco's approach.

Q.14 - Having decided on your approach to the threshold question, what did you have to do next in developing your cost study?

A. Well after we decide on the cost causation approach -- or at least I have decided that is the way to go -- the next question in dealing with these costs is to we take the fixed variable approach to classification or do we take some other approach?

The fixed variable approach is to say well fixed costs

are allocated on demand thus the utility has to build these fixed -- these plants to meet the -- accommodate the peak demand. And so you allocate all fixed costs on demand, you allocate all variable costs on energy. It;s very simple. It's probably the oldest and most widely used method. And if there were no history in New Brunswick, that is probably the approach that I would take.

However, you can't just make decisions in a vacuum. I think you have to look at the history of the jurisdiction where you are working. And looking at the 1992 decision, particularly page 11 of that decision, if I could read just a little bit of that. It says, "The Board does not accept the proposition that generation costs should be classified as 100 percent demand." So the Board is rejecting the fixed, variable approach.

It says, "Decisions on the construction of major generation facilities have been made on the basis of comprehensive reviews of both capital and energy costs. It is highly likely that future decisions on generation facilities will be made on the same basis."

So the Board's philosophy, it came down on the basis of 60/40, but it didn't just accept the 60/40. It adopted a certain philosophy. And that philosophy is that I think

the Board noted that it accepted the 60/40 but it ordered NB Power to prepare a study to support that.

And of course, NB Power did that in 1993 and that was the Reed analysis and that analysis basically said that we have examined the system and based upon the characteristics of the system and the planning criteria used, we believe that the Peaker Credit Method, which is also called the Equivalent Peaker Method, supports the use of the 60/40.

Q.15 - Dr. Rosenberg, could you then explain what the ramification of choosing the Peaker Credit Method is?

A. Well if you look at the NARUC manual, you see that the Peaker Credit Method or the Equivalent Peaker Method, the heart of it is a system planning method. It says how does the -- how does the system planner react to the load curve.

So unless you get a clear picture of how the system planner responds to the load curve, you can't get a clear picture of how the customer's usage influences costs, or imposes costs on the system. And the Equivalent Peaker Method says that -- says yes, we do have to build capacity to meet the coincident peak, however, not all capacity is created equal.

The planner, when he is choosing to build a new plant,

has a choice of technologies. And these choice of technologies span a whole spectrum. At one end of the spectrum, you have something called a peaker, okay. And the prototype of a peaker is usually taken as a combustion turbine. And a combustion turbine, what are the characteristics of a combustion turbine?

It has very low capital costs, very cheap to build. You know $400 a kw maybe, sometimes less, sometimes a little more. But they have very high running costs, very high fuel costs. So that is one end of the spectrum.

The other end of the spectrum you have a base load plant and probably a nuclear plant is probably the paragon of a base load plant. And a nuclear plant of course has the opposite characteristics.

The nuclear plant has very high fixed costs, it is expensive to build. You know, some nuclear plants have gone as high as 6,000 a kw. But it has very low running costs. Nuclear fuel is very cheap per megawatt hour.

And then of course you have a spectrum in between, intermediate plants, combined cycle plants, coal plants, oil fired plants, things like that.

So the Equivalent Peaker Method says that I have a choice of technologies. And therefore I have to recognize that in my cost allocation process.

Q.16 - Could you explain, Dr. Rosenberg, how the use of the Equivalent Peaker Method impacts cost allocation and classification?

A. Well again you have to go back to the system planning. How does the system planner choose which plant to build, the peaker plant, or the base load plant or something in between. He looks at how long he expects the plant to run, okay.

If the plant is only going to run a few hundred hours, and some plants only run a few hundred hours, sometimes even less, then he is going to choose the peaker plant because that is the most economic choice.

If he expects the plant to run a long time, and we say expects the plant to have a large capacity factor, okay, you know 4,000 hours, 5,000 hours, 6,000 hours, then he will choose the base load plant because the plant will run long enough that the fuel savings will far more than outweigh the additional capital cost.

So it is that decision that we try to capture in the Equivalent Peaker Method. And the most I guess notable feature of the Equivalent Peaker Method is that it says okay, we will compare the capital costs of the plant to the cost of a combustion turbine since the combustion turbine is the peaker. And we will classify all that

excess cost as energy related. Because we have spent that capital to save fuel. That is why this method is also frequently called a capital substitution method.

But in my view, that is only part of the story, okay, because, a utility doesn't seek to minimize fuel costs, it seeks to minimize total costs. So you can say, well when a utility decided to put in a peaker or an oil fired plant, it decided to spend more fuel to save capital. I mean, that is just as true. You have to look at the total picture and just to say, we spend capital to save fuel, even though that is the glib answer, it is probably -- it is certainly an incomplete answer and in my view, it could be very misleading.

Q.17 - Dr. Rosenberg, in your review of the Board's 1992 decision, do you believe the Board has acknowledged this duality in the past?

A. Yes. I think the Board has acknowledged it. I think Mr. Knecht also has acknowledged it. Mr. Knecht made reference -- there is this duality, as I said, between capital costs and fuel costs. And if I can just quote from Mr. Knecht, he said, "By the same token, intermediate load and peaking capacity generators are lower capital costs, high fuel cost technologies which are efficient to operate only at relatively low capacity factors. In

effect, these technologies accept higher fuel costs in order to reduce capital costs. These technologies generally only run during peak periods and therefore, customers who disproportionately contribute to peak demands are more responsible for these costs. As such it is equally tempting to classify some energy related costs as peak demand related."

Now I think where the Board have made this observation about duality in the 1992 decision was at page 30 of that decision where the Board noted higher winter energy costs may occur because during that season more use is made of generating units with low capital costs and high energy costs. If so, and the higher winter energy costs are to be selectively allocated to rate classes, then it would be appropriate to allocate the lower capital costs in a like manner.

And I agree with both those observations. I think the Board hit the nail right on the head in that observation and I would just paraphrase that observation to make it apropos to the cost allocation process. So thus if higher capital costs are to be selectively allocated to the higher load factor classes, as the Equivalent Peaker Method does, then it would be equally appropriate to allocate the lower fuel costs associated with those base

load plants in a commensurate manner.

Q.18 - Having done that in your study, Dr. Rosenberg, did you make any other fundamental modifications to Disco's study?

A. Yes, I did. And I said I tried to capture both sides of the coin here. So when you allocate costs on energy or anything other than demand, you are allocating a higher -- a higher kw costs to the high load factor classes. It's just a mathematical result. If you allocated energy to high load factor classes, you will get a higher capital cost per kw. And so as I said, I tried to mirror that in the allocation of the fuel cost.

The other thing I did was that I recognized that the concept of the breakeven point. And by that, I mean if let's say you decide that the breakeven point of a coal point is 4,000 hours. That if the plant runs more than 4,000 hours you are going to put in a coal plant, then that energy up to 4,000 hours is responsible for your decision to build a coal plant instead of a peaker. But any energy usage past that point is irrelevant to the cost of building that coal plant.

In other words, you might say if it runs 5,000 hours I am still going to put in the coal plant. If it runs 6,000 hours, I am still going to put in the coal plant. So all that energy past that breakeven point, that breakeven

point is the point where you are indifferent as to which plant you put in, okay, because the capital cost and the fuel cost offset each other at that point, then any usage past that point is irrelevant to the decision making of the planner. And if it is irrelevant to the decision making of the planner, it is irrelevant to the imposition of capital costs.

So I have tried to remove those costs from the cost equation since they are irrelevant to the cost causation process.

Q.19 - And did you make any other changes to Disco's study?

A. Yes, I made one other change to the Disco's cost of service model. And that had to do with the export credits, I believe. The -- again, the -- I went to a cost causation philosophy and -- instead of how it's billed. So I reclassified the export credits partly on demand and partly on energy. And I would note that Mr. Adelberg and Mr. Garwood made a similar change as well.

Q.20 - Do you consider your proposed cost study as ideal for Disco?

A. No, my study is not perfect. No studies -- no cost of service study is absolutely perfect and accurate. That's why we have bandwidths -- tolerance bands on the revenue to cost ratios, usually between 95 and 105, to recognize

that cost of service studies are imperfect.

Did I have to make simplifying assumptions to do my study? Yes, I did have to make simplifying assumptions to do my study. But every study has to make simplifying assumptions.

So I guess my point here is that the perfect should not be the enemy of the good. I think that my study is the only one on the record that is faithful to the Peaker Credit Method both on the capital side and the fuel side. And as a result I think it recognizes the totality of the Peaker Credit Method, not just selective aspects of it. And therefore I would submit that the record -- or the study that I have submitted is the most accurate one on the record.

Q.21 - Dr. Rosenberg, some of the other experts in this proceeding have made reference to marginal cost studies that had come in after the filing of your evidence. Could you just briefly comment on your views of their evidence with respect to potential approaches to marginal cost studies going forward?

A. Yes. I believe Mr. Knecht made three points on the subject of marginal cost studies.

First he said that marginal cost studies can resolve some thorny issues that are inherent in embedded studies.

Secondly, he felt that marginal cost analysis was more consistent with public policy, specifically on deregulation.

And third he observed that based on some marginal costs that he looked at in the past, he observed that there was not much difference between serving 100 percent load factor load and a seasonal load, you know, one that just peaks in the winter time.

Messrs. Adelberg and Garwood of course go even further. They believe that marginal cost analysis is superior to imbedded cost analysis and I think they sort of disparage any imbedded cost study as basically a futile exercise.

I differ with all these gentlemen, all three of these gentlemen. I think that embedded studies should be the benchmark of how costs -- how revenues are allocated -- how costs are allocated and therefore how revenues are allocated.

And again, my reasons for coming out in favour of the embedded studies is first of all, none of these witnesses have presented a complete marginal cost analysis for the Board's consideration. So really the only complete thorough marginal analysis we -- cost analysis we have is the embedded analysis. There just is not any marginal

cost study on the record to consider.

Secondly, in my experience I'm not aware of any Canadian provinces that use marginal cost analysis to allocate the revenue requirement to the various customer classes, various service classes. I could be wrong but I'm not aware of any. I know Alberta does not, British Columbia does not, Nova Scotia does not. So I'm not aware of any Canadian provinces that do it.

I am aware of six states in the United States that use marginal cost analysis. I might have missed one or two, but I know California, Oregon, Washington, Nevada, Montana, Illinois, possibly Maine, I'm not sure about Maine. But all the other states use embedded cost analysis. So I would not consider those six or seven states or whatever to be a ringing endorsement of marginal cost analysis.

The third reason I take the position that I do on this topic is that marginal cost analysis is fraught with lots of controversy, as much so if not more than embedded studies, and I don't believe there are any more objective than embedded studies.

The fourth reason why I would recommend using -- going the embedded route is that if you go with the marginal cost study, the marginal cost approach, there is an extra

step to the process, because after you figure out, you know, class A's marginal cost is $10,000,000 and class B's marginal cost is $20,000,000, and so forth, you go all the way down, and let's say we could all agree on those matters, and you sum up all those marginal costs, the sum that you get will only by the sheerest coincidence be equal to the revenue requirement. So when you sum up the marginal cost you may get, you know, a billion dollars and the revenue requirement might be a billion, two. Or it might be 800 million. So they won't be equal. So then you have an extra step in the process. How do you reconcile the marginal cost analysis that you have on the one hand with the revenue part, the dollars that you have to allocate to the classes on the other hand. And there is lots of controversy involved in that reconciliation process.

The fifth reason why I favour the embedded study is, as I have noted in my response to interrogatory 1 from the PUB, there are many pragmatic reasons why even under authentic competition, prices will not necessarily gravitate towards marginal costs, let alone equal marginal costs. Professor Kahn, for example -- Alfred Kahn -- who is a former chairman of the New York Public Service Commission, very well noted advocate of marginal cost, as

most economics professors are -- he says in his book that there is a strong tendency in industry to price on a full cost basis, usually computed as average costs over a period of time, with a mark-up to make sure that they recover their total costs.

So as a practical matter, as a pragmatic matter, I still think you get back to average costs.

The sixth reason I can't agree with marginal costs -- well I can't agree that there would be very little difference between serving 100 percent load factor customer and serving a seasonal customer. My experience with markets across North America where there are wholesale markets show sharp distinctions between on peak prices and off peak prices. For example, in the New England ISO and PJM and the market in Alberta, you have caps. There is market caps of a thousand dollars a megawatt hour. You wouldn't need market caps of a thousand dollars a megawatt hour if prices were the same across all the hours.

I think there is a -- my experience is that high load factor customers are cheaper to serve and in places where they can go out and get competitive bids you usually get much more economic bids than low load factor customers.

So that's the basic reasons for my recommendation to

stick with embedded cost studies as the basis for allocating revenue.

Q.22 - Thank you, Dr. Rosenberg. Just briefly now then on the two remaining issues -- and again, Mr. Chair, we did spend a little more time on that due to the technical nature of the cost of service aspects. Your second point was on rate design, Dr. Rosenberg. Could you just give the Board your general views as presented in your evidence on this topic, please?

A. Well first I would note that on the issue of rate design there appears to be much more unanimity among the witnesses, at least that's how I read their testimony. I think Mr. Marois, Mr. Knecht, Messrs. Adelberg and Garwood, are all receptive to ultimately eliminating the differential block, the declining block rate and the residential rate, so as to be more reflective of cost of service. Mr. Knecht I believe expressed impatience with the slow pace of eliminating the declining block and the proposed narrower differential. And Mr. Adelberg and Mr. Garwood noted that the -- and again I'm quoting from their testimony -- the primary objective of rate design is to minimize discrimination if customers with different demands, and thus imposing different costs, were charged the same rates. And I couldn't agree with that

observation more. That's a very astute observation.

So that's my general view on the rate design, that we should eliminate the declining block rates because -- I'm not saying -- I mean, there is some declining -- there is some places where declining block rates are appropriate, if it's based on cost, but in the situation that we have here it's not based on costs. It's antithetical to cost.

So my view on the -- my recommendations on the rate designs for the residential class is that first of all we eliminate the declining block rate completely, and instead we have seasonal rates. Seasonal rates are very easy for customers to understand. I would imagine, for example, that the Algonquin Hotel has different rates than it does in July. It's an easy concept to understand. It's also easy to administer. You can use the same meters that you have now.

I think the rate design that I proposed for the residential class is more cost based than the one proposed by Disco, and you can see that by looking at the revenue to cost ratio of the heating class -- the heating customers versus the not heating customers. What I have done is I have narrowed that differential. It's more conducive to demand side management, to DSM. It's more conducive to fuel switching. So it's more efficient.

I don't believe that my proposals are unduly disruptive for the vast majority of customers.

The other thing I would note is that in responding to certain interrogatories about my proposed rate design, I was asked to do some bill impact analysis, you know, what are the rates now, what are the rates based on Disco's proposed rates, what are the rates -- what are the revenues based on your proposed rates.

And when you do such analysis what you normally do is you use the same billing determinates. You know, you take the billing determinates, you multiply it by some -- this person's proposed rates, you multiply it by my proposed rates, and you look at the difference. I think that's misleading, because the whole purpose of putting in seasonal rates is to change the consumption behaviour of a customer. I mean hopefully the customer will react to those billing rates and lower its winter usage, okay, and get a more even rate.

And so I think you have to keep that in mind when you look at bill impacts, is that those bill impacts don't take into consideration the fact that customers should respond to the seasonal rate design and change their behaviour.

Q.23 - Dr. Rosenberg, could you likewise briefly summarize

your recommendations regarding rate design for the GS classes?

A. Yes. Likewise for the general service classes really my recommendations are directionally the same. As for the residential I see no reason why we could not have equalized rates for general service I and general service II. The differential there is solely for promotional reasons, not cost of service reasons. The 2001 New Brunswick White Paper noted that this differential between general service I and general service II is not aligned with the policy of the province. Furthermore I would submit that my proposals regarding the general service classes do not violate gradualism, A), because my GS II revenue requirement is the same level as that of the Disco, B), my GS I revenue requirement actually is a decrease, is less revenue than what the Disco had proposed, and, C), if you look at the revenue to cost revenue of the two classes, even after I equalize rates, there would still be a differential between the two classes. And that's because they have different usage patterns.

So I think what I proposed is certainly a step in the right direction. Perhaps it doesn't go all the way to cost but it certainly is a step in the right direction.

Q.24 - And, Dr. Rosenberg, like with the residential class, are you proposing some seasonal differentiation in the GS I and II classes?

A. Yes.

Q.25 - Could you explain to the Board what you believe the result will be if the Board does not move to eliminate the residential declining block and equalize the GS I and II rates?

A. Very simply, in my view if you do not do that you will be sending incorrect price signals to the existing and potential electric customers as to the actual cost that they impose upon NB Power.

Q.26 - And likewise why is the seasonal differentiation component so important in your view?

A. Well NB Power is a markedly weather sensitive winter peaking utility. They have higher winter usage for the heating usage predominantly, and that is what is driving the peak, and it's also driving the higher fuel cost. And failure to recognize this reality will lead to a failure to recognize cost causation. And in my view, if you don't recognize cost causation that's -- you are being counterproductive to the goals of energy efficiency and the energy goals that this province has set.

Q.27 - And on your final topic then, Dr. Rosenberg, could you

just briefly describe for the Board your proposal for a standby rate for customers with self-generation?

A. Yes. Let me just explain what standby rate is. Standby rate is when a customer puts in its own generation, typically cogeneration, so a customer has on-sight generation, but of course the customer's generation can fail. Units trip, you know, things happen, turbine blades fall off, things like that. And when that happens they have to rely on the utility for back-up power, for standby.

Now normally that type of service is a very sporadic service. I mean it happens just when the unit trips. Frequently it's for very short duration. And as a result the load shape and the coincidence factors of that standby service differ markedly from the coincidence factors of a full service -- a full requirements customer who is normally on when the peak is on, when the utility uses peak.

And so a rate that's perfectly cost based for a full requirements customer is not cost based for standby service. And so many utilities across North America have special rates specifically for standby service, and that is what I am proposing that New Brunswick Power institute, a special rate for standby service.

And then I have noted in my evidence there are certain features of a standby rate, how you can go from a full requirements rate and sort of evolve it into a standby rate. And the principal feature is called a prorated daily demand charge.

So basically what that means, instead of having a demand charge based upon your peak demand for the month, you have a demand charge based upon your peak demand for the day. And that for various technical reasons addresses the problem with the full requirements rate versus the standby rate. That's not something that I have come up with. It's probably the most common structure used for standby rates.

Q.28 - And, Dr. Rosenberg, again could you just explain why you feel such an approach is required?

A. Well if you don't have an appropriate rate for standby service you could be discouraging what would otherwise be an economical cogeneration project.

MR. MACDOUGALL: Thank you, Dr. Rosenberg. Thank you, Mr. Chair. That's the completion of Dr. Rosenberg's direct evidence and he is available for cross examination.

CHAIRMAN: Good. Thanks, Mr. MacDougall. We will take our 15 minute break at this time.

(Recess)

CHAIRMAN: It's my understanding, Mr. Plante, that you have no questions of this witness?

MR. PLANTE: That's correct, Mr. Chair.

CHAIRMAN: Okay. Thank you, sir. Any preliminary matters, Mr. Morrison?

MR. MORRISON: No, Mr. Chairman.

MR. MACDOUGALL: Mr. Chair, just one comment. NB Power has been kind enough to put their binders and everything -- a set of those, so that I did not have to drag a second set down to St. Andrews since they were bringing one anyway. Dr. Rosenberg is not fully familiar with all of the system although we have taken him through it, and since he has a Ph.D. in math it shouldn't be too difficult, but bear with him if he has to turn around occasionally and get used to the numbering system behind.

CHAIRMAN: Okay. Is that what it takes to be able to use that numbering system? I guess I'm out to lunch. Go ahead, Mr. Gorman.

CROSS EXAMINATION BY MR. GORMAN:

Q.29 - Thank you, Mr. Chairman. Good morning, Dr. Rosenberg. My name is Raymond Gorman. I am the solicitor for the municipal utilities and we would take power through the wholesale rate.

A. Good morning.

Q.30 - I hope you are enjoying the Indian summer here in New Brunswick.

A. Actually I enjoyed New Brunswick more four years ago when I came in August, but --

Q.31 - I can understand that. I just have a few questions first of all arising out of the direct evidence that you gave this morning, and I guess I'm going to follow the order in which you testified. And the first thing I guess that you said was the cost of -- the second part of your testimony dealing with cost of service study dealt with residential and general service rate designs.

A. The second part of my testimony was on residential and general service rate design. The first part was on the class cost of service study.

Q.32 - Yes. And when you dealt with the rate design for residential and general service you didn't specifically focus on wholesale anywhere in your report?

A. No, I did not.

Q.33 - You referred again in your direct testimony to the 1992 decision of this Board and there was some discussion with respect to the 60/40 split. So you would agree that obviously the split that was determined was appropriate in New Brunswick in 1992?

A. My -- obviously the document speaks for itself, but my

reading of the document says that the Board was not just fixated on any particular numerical example. They came down on a certain philosophy or approach to cost allocation and that was what was most important. And then of course they noted that things might change and that you might have to change the 60/40 as appropriate to the circumstances. So that they adopted a methodology, if you will, or a philosophy of an approach to cost allocation, and that was the key to the 1992 decision. At least that's my understanding of it.

Q.34 - But you would agree that that doesn't mean the numbers don't matter. Effectively what the Board came down with was a 60/40 split.

A. They did use those numbers in the decision, yes.

Q.35 - And do you agree that -- and I know there was much debate back in 1992 about this, but do you agree that that would not be an unusual split?

A. I don't think you can -- I don't think the term usual or unusual really applies to it. I mean certainly there is a whole range. Is it outside the range? No, I don't think it's outside the range, but I don't think you can say the number itself is usual or unusual.

Q.36 - Could I say it's traditional?

A. No.

Q.37 - Why not?

A. Because there is no tradition involved. It's a matter of economics. It's not tradition.

Q.38 - So you wouldn't agree that other Canadian jurisdictions have used that in the past?

A. They may have used it but the numbers they used would of course depend upon their philosophy and their circumstances.

Q.39 - Thank you. In your direct evidence this morning you referred to I guess virtually all of the other experts except for one. I don't believe you referred to Ms. Zarnett's evidence, and you disagreed -- I just want to make sure I understood that you disagreed with their use of marginal costs. You effectively disagreed with all of those experts, is that correct?

A. On that particular subject, yes.

Q.40 - In your testimony this morning I think you stated that the object of rate design is to minimize discrimination, is that accurate?

A. Yes. I think that was a phrase that Mr. Adelberg and Mr. Garwood used in their testimony. I thought it a very apt phrase.

Q.41 - And it's one that you would adopt as your own or you would accept as a reasonable statement?

A. Yes.

Q.42 - And ideally would you agree that perhaps rather than just to minimize discrimination, perhaps one should attempt to eliminate it altogether?

A. You try to eliminate undue discrimination. Sometimes you do want to discriminate because there are certain policy objectives that you have, and you are conscious of those policy objectives when you make your decision. And so you feel that making these decisions are for the public good, and in that case I guess I would call it due discrimination. As long as all the facts are considered, that's certainly the prerogative of the regulator.

Q.43 - Certainly. But if there were no policy considerations, then would the object then be to eliminate discrimination?

A. If there were no policy objectives, the objective should be to have rates based on cost of service which I think most people would say would -- is fair and equitable, yes.

Q.44 - So if there were no policy considerations, should the goal be to essentially narrow the differentials in the revenue to cost ratios?

A. Within the 95 to 105 bandwidth. Once you get -- I don't think cost of service studies are that accurate that -- in other words, the cost of service study is you are

painting with a little bit of a broad brush, and I think what you are saying is well as long as I'm within these lines, that's a tolerance bandwidth and that's satisfactory.

Q.45 - I understand the concept of this tolerance bandwidth but what I'm saying is that if the object of rate design is to minimize discrimination, or undue discrimination, then in a perfect world wouldn't everybody be at unity, for example, rather than within that bandwidth.

Q.46 - Well as a matter of fact, my experience in British Columbia and Alberta, Nova Scotia, all of those locations use the 95 to 105 bandwidth, so -- and they all consider that anything within the 95 to 105 bandwidth to be appropriate and good enough for -- we don't live in a perfect world. We just can't measure these things, you know, to the nth decimal place.

And somebody once said, why do economists use decimal points? And the answer is to show they have a sense of humour. You know, I think you are dealing with complex issues and you are trying to get as accurate a representation as you can. And like I say, the folks in Alberta and Nova Scotia say as long as the rates are within the 95 to 105 bandwidth, we are satisfied that those rates are cost of service.

Q.47 - Well would you recommend a ten percent spread then in terms of those percentages?

A. To be perfectly honest, I haven't re-examined that issue. I mean the '92 decision said 95 to 105. That's within my experience as an appropriate bandwidth and so I have just accepted that. I haven't re-examined that issue.

Q.48 - Would you agree that there is a certain amount of judgment involved if a utility puts one rate class at 95 percent and another at 105 percent, that in fact there are a lot of judgment calls that have to be made?

A. Unfortunately rate making and rate design is not a cook book. You know, you don't follow things, you know, put in half a cup of this, two teaspoons of that. There is a certain amount of judgment in them, so that's correct. But it should be reasoned judgment. It shouldn't be capricious or arbitrary judgment.

So for example if a class is 115 and you want to bring it to the bandwidth, I mean my first thought is, well why should I bring it all the way down to 95? I mean it's 115. Let me bring it down to 105. Conversely, if somebody -- if one class is at 70 and I want to bring that class to the bandwidth, I probably wouldn't bring it to the top of the bandwidth. I would bring it up to the 95

point. So it's judgment, yes, but I don't think it's capriciousness.

Q.49 - Well if you have a ten point spread in the bandwidth and let's for example say you had two classes that were within the bandwidth, let's say one was at 103 and one was at 97, if you were to move them at all, wouldn't the goal be to move them closer to unity rather than away from it?

A. Unless there are other considerations, and there are considerations, moderation, things like that. Sometimes there are considerations as to the competitiveness of your industrial customers. So there are other considerations that are valid considerations that a regulator may want to -- may wish to consider.

Q.50 - And these would be a matter -- I think essentially what you are saying -- a matter of perhaps public policy, is that where you are going?

A. In essence, yes.

Q.51 - And if a regulator were to go there it would be really a matter of them understanding and having some background with respect to that public policy?

A. Yes. I would say yes.

Q.52 - If I could take you to your report that is exhibit EGNB-1, and specifically I'm referring to schedule 2. Schedule 2 would be the second last page. Sorry. I would

like to take you to schedule 1 first. I'm sorry.

A. Schedule 1.

Q.53 - In reviewing schedule 1, which is a comparison of supply cost classification allocation methods, and it's the NB Power study as compared to your study, is that correct?

A. That is correct.

Q.54 - And I see -- and I haven't added this up precisely, but I guess you are a mathematician and presumably if I am incorrect in my numbers you are going to point that out to me. But under residential essentially the supply cost according to your study is about $13,000,000 more than it would appear in the NB Power study?

A. About thirteen-and-a-half, yes.

Q.55 - And if I go down to wholesale, something in the order of just under $2,000,000 would be allocated as total supply cost in addition on yours from the NB Power study?

A. About 1.7, yes.

Q.56 - So the two of them together as I say roughly 15,000,000. and if I look at the large industrial, column 7, I see that you show a reduction there of about 15,000,000. So would it be fair to say that that reduction is based on allocating more cost to residential and wholesale and less to large industrial?

A. Not exactly, but I'm not moving -- that's just the outcome of a situation and the reason it comes out that way is because as you see from my evidence, I believe that the study filed by the Disco under allocates costs to the classes -- to the winter peaking classes, and over allocates costs to the classes that have the flattest load shape and the industrial class probably has the flattest load shape, and so they are the ones that show up as having the lower cost under the *

Q.57 - No, I understand that, but dealing just with the consequences of your study, it would be effectively a shift in terms of cost away from industrial and essentially the lion's share of it under residential.

A. I don't like to characterize it as a shift. I like to characterize it as a more accurate representation of what these classes are actually imposing on the study. It's only a shift in the sense that the Disco study didn't accurately portray what the cost causation was.

Q.58 - Okay. Well let's put it this way. Your study shows an increase of total supply cost to residential of somewhere in the order of $13,000,000.

A. Compared to the Disco file study, yes.

Q.59 - Yes. And wholesale is something just under 2,000,000?

A. Compared to the Disco study -- that's the difference

between the two studies, yes.

Q.60 - And that effectively would be the difference between the two studies. There are other minor differences but if I add those up, they seem to account for most of the difference.

A. Well there is about a million dollar difference in general service I. In other words, my study allocated that a million dollars less to the general service I class allocated about a million-and-a-half more to the general service II class. And again that's because the general service I class has a higher load factor than the general service II class.

Q.61 - Okay. But the bulk of this difference is made up on residential, about 13,000,000?

A. The residentials account for 40 percent of the supply cost. So it's a big picture, yes.

Q.62 - Now if I ask you to flip to schedule 2, and this is a comparison of our revenue to cost ratios between the NB Power CCAS and the recommended CCAS at current and proposed revenue.

A. Yes. By proposed I believe this represents the Disco's proposed.

Q.63 - Yes.

A. Yes.

Q.64 - And I guess if we look under the NB Power column first, the revenue cost ratio to proposed revenue is 95 percent, and I guess you have said that's within the bandwidth.

A. Who are we looking at now?

Q.65 - Sorry. Column 7, large industrial, under the NB Power CCAS.

A. Yes. 95.

Q.66 - And I guess you are saying that that's appropriate. It's within the bandwidth?

A. That's within the Board's directives, yes.

Q.67 - And so if I move over to your recommended CCAS large industrial would be at one and you also would agree that that would be appropriate?

A. Well all I'm saying this is -- you have to understand what this schedule does. I did not make a recommendation or revenue allocation recommendation for all the classes. I did not say, assign X -- this amount of dollars to this class, this amount of dollars to this class, this amount of dollars to this class. So this schedule is merely an expedient to see, using the Disco's proposed revenue, where things fall out under their study versus where things fall out under my study. It's not a recommendation as much as it is just something that the Board can see what the results of the Disco's proposals are.

Q.68 - So are you saying it would be just for illustration purposes?

A. That's correct. Just for illustration purposes.

Q.69 - If I take you down to column 10 on the wholesale rate class, and you will see under the NB Power proposal it would come in at 1.05 and again according to your evidence that's within the bandwidth.

A. That's the Board's decision.

Q.70 - Yes. And if I look at the recommendations under your study it would fall to 1.03, and would your evidence be that a revenue to cost ration of 1.03 would also be appropriate?

A. As I have said I have not made specific recommendations as to how to allocate the revenue requirement. My recommendations are more to how to conduct an appropriate cost of service study. What this shows is that under my cost of service study the Disco's proposed revenues would result in the wholesale class being at a revenue to cost ratio of 1.03, which is within the bandwidth. It doesn't mean that no party can recommend that it should be different. That would be up to that party to recommend and make a case for.

Q.71 - Okay. But the wholesale at 1.03 as opposed to 1.05 would be appropriate in your view then?

A. It would be cost based according to the Board's guidelines, yes.

Q.72 - It falls within the bandwidth.

A. It falls within the bandwidth.

Q.73 - Could I just have one moment, please. Thank you, Mr. Chairman. I'm going to refer you to page 25 of your pre-filed evidence at EGNB-1.

A. Yes, I have that.

Q.74 - And I'm sure you are familiar with that page. You cited cases that were decided by regulators in Texas as an example of the symmetrical corollary and fuel cost allocation. Were you personally involved in any of those cases?

A. No. But one of my partners was involved in the Texas cases.

Q.75 - That's what I'm referring to is the Texas cases.

A. Yes. One of my partners was involved. I was not personally involved. My firm was involved.

Q.76 - Do you recall whether or not the applicant was an integrated utility?

A. I believe it was. That's my understanding.

Q.77 - So in these Texas examples then, the generation being allocated was part of the applicant's and the cost was incurred within the applicant as a corporation?

A. That's correct. That's my understanding.

Q.78 - Do you recall or are you aware of whether or not the applicant procured any generation under power purchase agreements?

A. I honestly don't know.

Q.79 - Are you familiar with any examples of approaches to the allocation of generation costs where generation is procured from a separate company or companies under a power purchase agreement?

A. No, I am not.

Q.80 - Are you aware of any other jurisdictions other than Texas that has really addressed this issue, and the same, any decisions?

A. I think I responded to that in one of the interrogatories.

Q.81 - You might be referring to PUB IR-2.

A. Yes.

Q.82 - And I think at that time you said that you hadn't conducted a formal survey and you don't possess any other citations that have addressed the issue?

A. That is correct.

Q.83 - Just one moment, Mr. Chairman.

A. But I would take my response to number 2 as more of a complete answer to your question.

MR. GORMAN: Those are all of my questions. Thank you.

CHAIRMAN: Thank you, Mr. Gorman. If my memory serves me correctly, the next would be the Public Intervenor. Do you gentlemen want to switch tables?

CROSS EXAMINATION BY MR. HYSLOP

Q.84 - Good morning, Mr. Chairman, Commissioners and Dr. Rosenberg. My name is Peter Hyslop. I am the Public Intervenor in this case. I have enjoyed very much your testimony. It has been a learning curve. I have been getting steady lectures on utility economics 101 from Mr. Knecht. And it is good to have a guest lecturer once in a while. We appreciate that.

A. There will be a short quiz after.

Q.85 - Well I think the quiz is just beginning but I'm not sure who for. But we will go from there.

A. Okay.

Q.86 - I was a little interested in your answers to my colleague, Mr. Gorman. And in particular some of your answers suggested that the role of a cost allocation study is important but it's not the be all and end all in setting rate and rate design. Would you tend to agree with that comment, Dr. Rosenberg?

A. It is probably the place they start from. It is the place they start from. And then they may temper the

indications of that study based upon certain considerations.

But it is the starting place.

Q.87 - Yes. And I noted in your testimony, you referred I guess to the classic text by Mr. Bonbright and others. And you said page 391 but I think you were referring to page 389. And I will just read a little bit and you can tell me if that is the section you might have been referring to.

A. Sure.

Q.88 - It is without doubt the most widely accepted measure of reasonable public utility rates and rate relationships is the cost of service -- and it goes on a little later -- and general cost base rates satisfy the commonly held multi-dimensional sometimes conflicting pricing objectives better than most non cost based rates.

Would that have been the section perhaps you were referring to, Dr. Rosenberg?

A. Yes, it could. One of the nice things about that book is you can probably find a quote that supports any position you want to take.

Q.89 - And I do want to refer to one of those. And it was the one at page 391. So I had to go looking for yours. But in any event, at 391 it states, Unfortunately no set simple identification of reasonable rates -- with rates

measured by cost of service is attainable. One major reason is due to the excessive complexity of rate relations or in the spirit of transaction cost economics, one might say it is due to considerations of bounded rationality.

And I will put in parenthesis here as it might apply to us people on the learning curve, or the cognitive limitations upon the human mind to perceive and process all relevant information.

And I take it you would accept that comment from the text as being applicable as well?

A. Right. Just as I don't believe you should make selective application of the Equivalent Peaker Method, I don't think you should make selective application of any reference manual. I would highly recommend that anybody who is seriously interested read the entire work and consider that work in the context of other work.

Q.90 - And I think that is a fair comment and I think you have been quite gracious about conceding the cost allocation study isn't the be all and end all of a rate case.

Now I do want to just start out a little bit by talking about the 14 step procedure that is found in EGNB-1, and that is the appendix B.

A. Yes.

Q.91 - And if I look at step -- sorry, I will wait until everybody gets there.

A. Yes, I have that.

Q.92 - Okay. And the first step is to classify the fixed costs between demand and duration related costs. Is that the first step you took, Dr. Rosenberg?

A. That is correct.

Q.93 - And in the broad scheme of things, this is the same approach that NB Power took with regard to their cost allocation except what they call energy you are referring it to as duration related cost. Correct?

A. My understanding -- no, I don't think I can agree with that. I mean, maybe in a very very broad sense, that is what they did. But I actually looked at the Equivalent Peaker approach. In other words, how much -- what is the cost of this plant, capital cost of the plant versus the capital cost of the peaker. Plus what NB Power did was they said we have got the 60/40, we are going to use it here and here. We are not going to use it here.

Q.94 - Yes.

A. With that understanding --

Q.95 - You came out at the same place?

A. I did come out at 60/40, yes, that's right.

Q.96 - And just the difference between what they refer to

energy, you are referring to as duration related costs?
A. I think that is a more precise term.
Q.97 - Yes. Okay. And duration related costs are the costs that are occurred in the generation of electricity over time or over a period of time?
A. Duration means over time, yes.
Q.98 - Yes, okay. And essentially then, we ended up with the same result. And the cost you used and I won't go into it because you covered it quite well in your direct testimony. You were using costs that were not based on the purchase power agreement. You were using the accounting costs -- the cost causation costs --
A. I was using the cost causation approach and in my opening statement I, I think, went into some length as to why I felt that is the most appropriate approach.
Q.99 - Right. And then you go on to allocate the duration costs to each of the customer classes. That would be part of the process that you took in your appendix B?
A. That is correct.
Q.100 - And the critical method or one of the critical steps that you used to determine the duration of these -- the costs -- generation costs to customer classes, you did a breakeven analysis based on different types of generation to a basic peak? Is that correct, Dr. Rosenberg?

A. That is correct.

Q.101 - So for example, you would have compared oil or gas or hydro back to in this case CC units or CT unit?

A. CT unit.

Q.102 - Yes. And in doing so, you determined that the generation costs from coal would be allocated to customer classes over a nine month period from October through to June, I believe.

A. Right. I resorted to months because I really didn't have accurate hourly data so I -- again, that is sort of an expedient that I used -- I used the nine months figuring those are the top nine months.

Q.103 - Right. And after you did your calculation of the breakeven period, you took the rough number and apportioned it in terms of a percentage of the year as opposed to an exact percentage of hours?

A. Correct.

Q.104 - And --

A. Because we do have accurate information about monthly usage.

Q.105 - Yes. And we don't have that with regard to on an hourly basis for the different classes. Correct?

A. That is correct. Precisely correct.

Q.106 - And it would not only aid you, but I suggest it would

aid myself and even NB Power at some point in time, if they were able to have this accurate data for each of the classes on an hourly basis. Would that be correct?

A. That would be nice, yes.

Q.107 - It would be helpful to us all, I expect?

A. Yes, it would.

Q.108 - And anyhow, go back to oil and gas in your analysis, when you looked at that you came to the conclusion that the fuel costs should be allocated amongst customer classes based on their usage in the month of January. And you did that as a proxy as well.

A. The fuel costs?

Q.109 - The duration costs?

A. The duration costs, yes.

Q.110 - Yes. And I think in your evidence you even stated that that was a bit of an accommodation to the low load factor customers because --

A. I think that choice, that expedient actually benefits the low load --

Q.111 - Yes, I understand that. So whatever class gets allocated, the oil, gas duration costs in January gets that same allocation under your methodology for the whole year because you have established the breakeven point to be in rough terms one month?

A. Correct.

Q.112 - Right. And the number of hours is of course based on your breakeven analysis that you did for each of the different methodologies -- or each of the generation methods?

A. That's correct. And that was based upon, I think, a integrated resource plan of NB Power's.

Q.113 - Is that the one they did just around the time they did for Coleson Cove, Dr. Rosenberg, do you recall, 2002?

A. I think it was 2002, yes.

Q.114 - Okay. Now you are familiar with the NARUC manual. It has been referred to many times during these hearings?

A. Yes.

Q.115 - Right. And just for the record it is found in exhibit A-14, tab 7. I don't think there is a need to specifically refer to it. But there is about a five page section in there that describes the Equivalent Peaker Method. Wold you be familiar with that, Dr. Rosenberg?

A. I believe I have looked at it once or twice.

Q.116 - Didn't write it, by any chance?

A. No.

Q.117 - Now in regard to that, I went through it last night and I couldn't find anywhere in that five or seven page description where it would refer to something called

duration related costs. Am I correct in my understanding from reading the Peaker Method? You will find it in exhibit A-14, if you wish to look at it?

A. I think I have my own copy. Yes, I have that. And could you repeat your question?

Q.118 - Yes, I could. When I went through the manual last night again and I probably haven't read it as many times as you, but I couldn't find in this manual a specific reference to where it discussed costs in terms of being duration related costs. Would I be correct that that phraseology is not found in pages 52 to 57 of the NARUC manual where it describes the equivalent Peaker Method, Dr. Rosenberg?

A. No, I'm not sure that's quite correct. On page 53, which is in part of the section on equivalent Peaker Method they have a section there, I think you will see it, called a digression on system planning. There is reference to plant allocation. And if you read the second paragraph of that section, that digression, I think you will see a very explicit description of the breakeven point, and they even use the term duration.

A peak load of intermediate duration for example, of 1,500 to 4,000 hours per year may be served most economically by a combined cycle unit. A peak load of

long annual duration may be served most economically by a base load plan. So they are describing exactly the planning process that is at the very heart of the equivalent Peaker method, and which is what I am trying to capture in the allocation.

Q.119 - Okay. But again, looking at this very briefly in terms of duration you are referring to the length of time for the capital cost to -- or the unit that you invest the capital in, correct?

A. This is the investment of capital, yes.

Q.120 - Yes. Okay. And when Mr. Ketchum did his analysis of the Peaker Credit or the Equivalent Peaker Methodology --

A. Could I --

Q.121 - Yes.

A. Let me put just one other point that I just see here. If you look at page 56 I think -- now on 56 they are not discussing the Equivalent Peaker Method but they are discussing a similar type method, and it's a rating method called the Base and Peak Method. And you will see starting at the bottom of page 55, the difference is that using the Base and Peak Method, the energy related excess capital costs -- and you can recognize that as, you know, applying to the Equivalent Peaker Method, are allocated on the basis of the classes proportion of on-peak energy. So

here they are using on peak energy instead of total energy.

Again the concept -- it's not exactly what I'm using but the concept is the same.

Q.122 - Okay. Now you have modified in your analysis in your cost allocation study the Peaker Method for purposes of presentation to this Board, correct?

A. I have tried to present complete Equivalent Peaker Method.

Q.123 - And going on from there, your purpose is to take the fuel costs for each type of plant on a month-by-month basis and figure out how much is to be assigned to each particular rate class?

A. That is correct. That is correct. Because in a fixed variable approach, costs -- fuel costs from one class to another class may differ because classes use electricity at different times of the day or different times of the season, whereas when you get into a methodology like the Equivalent Peaker Method, there are two reasons why one class's fuel costs may be different from another class's fuel costs.

One reason again is the same as the fixed variable approach because they use it at different times of the day or at different times of the year, but the other reason is because you have allocated more base load plant to one

class and more peaking plant to another class.

Q.124 - Sure. And the way that you allocate or determine the basis of the duration related costs is on the same basis, each class pays for its capacity from the equivalent peak.

A. Would you repeat that?

Q.125 - Yes. I'm just trying to get at the basis upon which you allocate the duration related costs, it's the same method that you --

A. Sorry. Yes.

Q.126 - I would like, Dr. Rosenberg, if we could move on to EGNB 2 which is the responses to interrogatories.

A. Yes, I have that.

Q.127 - Okay. And I'm referring specifically to interrogatory EGNB PI IR-1 and in particular I believe it's attachment B.

A. We are looking at PI --

Q.128 - Yes.

A. -- IR-1.

Q.129 - Yes.

A. Attachment B.

Q.130 - Yes.

A. I believe that was asked to provide work papers.

Q.131 - Yes, it was.

A. Yes.

Q.132 - And I believe that this is your Equivalent Peaker Analysis of -- I'm sorry -- assuming everyone has it, moving on with the questioning on it. This was your Equivalent Peaker Analysis, Dr. Rosenberg?

A. Well I can't take all the credit for it. Most of it came from I believe IR-36.

Q.133 - Yes. Which was the NB Power Equivalent Peaker based on the accounting costs, correct?

A. No, not on accounting costs. On the capital costs.

Q.134 - Capital costs.

A. Yes.

Q.135 - And to the best of your knowledge, this was based on the 2002 accounting costs or capital costs?

A. That's to the best of my knowledge, yes.

Q.136 - Yes.

A. Book costs 2002, yes.

Q.137 - Yes. And in the bottom right hand corner of this attachment B, there is a block that you have got a square around, correct?

A. That's correct.

Q.138 - And the 40/60 demand energy split that's listed there, that's the same split that NB Power came out with as a result of doing their analysis and you accept that, for a system as a whole?

A. For the system as a whole, yes.

Q.139 - Yes.

A. But it's different for different types of --

Q.140 - That's correct. And that's what you have got down the remainder of that block, I believe.

A. That is correct.

Q.141 - Right. And so for example, for nuclear you have classified the fixed cost at 30 percent/70 percent.

A. Roughly, yes.

Q.142 - Yes. I'm rounding -- I hope I'm rounding the right way.

A. Yes, that's correct.

Q.143 - Good. And now that you have these percentages based on 2002 costs, my question becomes you then applied them to the 2006 costs for each type of unit in your analysis, correct?

A. That's correct. But in my experience I don't think you would get a very different picture if you updated to 2006. These things tend to be very, very stable over time.

Q.144 - Yes. Okay. Well we will go on and maybe talk about that a little bit. And so you have made an assumption I guess that nothing substantially has changed -- would change very much over time with regard to system fixed

costs.

A. I mean if NB Power had built a new nuclear plant between 2002 and 2006, you know, I would say, well gee, we have got to look at that --

Q.145 - Yes.

A. -- but I don't think anything really substantial has changed.

Q.146 - We are going to talk about that a little bit too before we are done, the nuclear plant, so -- so dealing with that, we know where you are coming from on the 2002 and 2006. And just by way of curiosity, did you do a system split of generation costs based on 2006 costs in your analysis, Dr. Rosenberg, do you recall?

A. No. My recollection was that we asked in an interrogatory NB Power to update their Peaker Credit analysis they did in 1993, to update that and that's basically what I used. As I said, I made one minor change on one of the units.

Q.147 - Courtenay Bay, I believe.

A. Yes.

Q.148 - Yes. So you didn't do it.

A. But that's a relatively small change.

(Off the record)

Q.149 - Now in your evidence -- I would like to go on a little

bit with some of the questions on the cost, and I refer you to exhibit A-16.

A. A-16?

Q.150 - A-16.

A. I have that.

Q.151 - Okay. And I would also ask you to keep the IR I had out, EGNB PI IR-1.

A. Okay. I will do that, Mr. Hyslop.

Q.152 - Thank you. And when I look at EGNB PI IR-1 under column 8, row 18, I show total fixed costs for the system at $285,000,000. Is that what you see, Dr. Rosenberg?

A. Total fixed costs 285,190, yes.

Q.153 - Yes. And when I go to --

CHAIRMAN: Sorry. Just hold on, Mr. Hyslop.

MR. HYSLOP: I'm sorry. Thank you.

CHAIRMAN: Next time reverse it and say, keep the IR that you have out and would you get. We are all scrambling up here. The IR that you had was PI --

MR. HYSLOP: IR-1.

CHAIRMAN: At?

MR. HYSLOP: Attachment B.

CHAIRMAN: B. Right. And we are looking at what page? A-16.

MR. HYSLOP: And I'm also looking at exhibit A-16, Disco

EGNB IR-9.

CHAIRMAN: Thank you.

MR. HYSLOP: You don't have it, Commissioner LeBlanc? Disco EGNB IR-9. It should be a table, Revised NB Power Distribution customer service class cost allocation study using Genco and nuclear accounting costs.

Q.154 - Now starting first with EGNB PI IR-1, the total fixed costs used at column 8, line 17 or line 18, are shown as $285,000,000. I think you agreed with that, Dr. Rosenberg?

A. Yes.

Q.155 - Yes. And when I looked at Disco EGNB IR-9 and in particular at column 7 and row 6, I show total non-fuel costs at $581,000,000, is that correct?

A. That is correct.

Q.156 - Yes. And I would suggest that that would suggest between 2002 and 2006 there was in fact some significant increase in the fixed costs?

A. No, I don't think that's correct. I think the major reason for the difference is that the 285,000,000 that we are talking about covers depreciation and financial costs, whereas the figure you are talking about includes about 256,000,000 of operation and maintenance expense which is not in the PI IR-1 attachment. That's the major reason

for the difference.

And so what I'm doing is I'm looking at just the capital costs which is depreciation, you know, interest, things like that, and that's how I'm getting my split. And then the O&M just follows from that. That's normally how the Equivalent Peaker Method is done. So the difference in figures that you just alluded to is not indicative of a great difference in things. It's the O&M expense that really accounts for a big difference.

Q.157 - Okay. Well I want to, if I could, just have a quick look at particularly on the Coleson Cove aspect of this, if I could.

A. Sure.

Q.158 - And if I go back to EGNB PI IR-1 --

A. Yes.

Q.159 - -- and I look at Coleson Cove, and in particular -- I get a total fixed cost of 13,000,000 for Coleson Cove.

A. That's what it's showing, yes.

Q.160 - Yes. Now I want to go over, if I could, to oil and gas line on EGNB IR-9, if I could.

A. Yes.

Q.161 - And I show Coleson Cove now at 138,941,000?

A. That's correct.

Q.162 - Right. And just so we are comparing apples and apples

because the OM&A cost you referred to is in the -- if we look at columns 3 and 4 for oil and gas we have 41,000,000 for amortization --

A. Correct.

Q.163 - -- and 58,000,000 for interest expense.

A. I agree with that.

Q.164 - Right. And wouldn't this at least suggest that between 2002 and 2006 something was going on at Coleson Cove in terms of new capital costs?

A. I think this Board is familiar with what has been going on at Coleson Cove.

Q.165 - Okay. Very good.

CHAIRMAN: Not familiar enough.

Q.166 - So at least with regard to Coleson Cove, there has been a change to the capital cost between 2002 and 2006.

A. I would agree with that.

Q.167 - Thank you. Now again sticking with Coleson Cove, I want to talk a little bit about some of the problems. And maybe before I get into specific exhibits a couple of questions. I take it you are familiar with the history of our Coleson Cove and orimulsion experiment here in New Brunswick, Dr. Rosenberg?

A. I have read a little bit about it, yes.

Q.168 - Okay. And I was at the Coleson Cove hearing and as I

understand it, we went about attempting to refurbish an oil generator and we were going to use orimulsion as a fuel. Is that your understanding?

A. That's in accordance with my understanding, yes.

Q.169 - Yes. And as I also understand the situation, the price for orimulsion was so good that we were going to intend to use this refurbished generation unit as part of our base load in New Brunswick, would that be your understanding as well?

A. My understanding is that the intent was to get significant fuel savings from the orimulsion as a result of this conversion. And also my understanding is that it didn't quite work out as expected. And to me that just illustrates a reason why even though the Equivalent Peaker Method treats all capital costs in excess of a combustion turbine as for purposes of fuel related. Sometimes the best laid plans of mice and men are about equal and -- to quote a Scottish poet -- and, you know, that's why you do sometimes expend capital costs that do not result in fuel savings and therefore they really shouldn't be considered as duration or energy related.

Q.170 - And to -- well first I can't leave the mice Scottish poet alone. He wrote one of his very finest poems about meeting a fine Hyslop lady at a fine Hyslop pub in

Dumfirdshire. I claim to be ancestry. But going on from that point perhaps then -- and I think maybe we are starting to hit on it, but perhaps the extent of it. I would ask if you could call up EGNB-2 which is the response to interrogatories, and in particular EGNB PI IR-1(d).

A. Yes.

Q.171 - And I would also ask to keep -- sorry -- EGNB PI IR-1, and I'm looking in particular at schedule D.

A. Schedule D?

Q.172 - Attachment D. This is in exhibit EGNB 2 and it's the interrogatories, Dr. Rosenberg.

CHAIRMAN: Would you give the two citations again, Mr. Hyslop. You have got us all lost.

Q.173 - Okay. Exhibit EGNB 2 --

A. Interrogatory from the Public Intervenor.

Q.174 - Correct.

MR. MACDOUGALL: Mr. Chair, if I could assist Dr. Rosenberg, he is not using this binder because he is using his own copies. It's the fourth attachment reference there, Dr. Rosenberg. They are A, B, C and D in the binder. So it's your attachment IR 1-D. For everyone else it follows tab B in the binder.

A. Yes. These were different Excel files. So I have the

last one, 1-D, yes. I have that.

Q.175 - Do you have it?

CHAIRMAN: Give us the two again and we will check them to make sure we got the right one?

MR. HYSLOP: It's EGNB-2. And I am referring to IR EGNB PI IR-1 and I am dealing with attachment D.

CHAIRMAN: And the second one.

MR. HYSLOP: The other one will be the break even analysis which will be EGNB-2. And I will be referring to Disco EGNB Disco IR-4.

CHAIRMAN: Thank you, Mr. Hyslop. Go ahead.d.

MR. HYSLOP: I apologize, Mr. Chairman. We get into the attachments, it's another step beyond what we are used to.

CHAIRMAN: Right. Thank you.

Q.176 - Now dealing with IR-4, the third column -- the third row down refers to Coleson Cove Orimulsion at $29.20?

A. Yes.

Q.177 - And that was the breakeven analysis and the numbers -- the fuel costs you used for the oil gas with Coleson Cove, correct?

A. I am trying to find that.

CHAIRMAN: You said third line down.

MR. HYSLOP: Third -- third row down. I am looking at EGNB Disco IR-4.

MR. SOLLOWS: EGNB IR-4.4.

CHAIRMAN: Disco.

MR. HYSLOP: Yes.

CHAIRMAN: Now the third line down makes sense.

MR. HYSLOP: Yes.

CHAIRMAN: Thank you.

MR. HYSLOP: I just want to make sure everybody has it.

A. This is not a data response from me. Oh, this is our response to the Disco?

Q.178 - That's correct.

A. Okay. Number 4. Yes. I have that.

Q.179 - I am looking at the third line down?

A. Yes.

Q.180 - And it refers -- and I am looking for the -- it says Coleson Cove Orimulsion?

A. Okay. Now, I am with you.

Q.181 - Okay. I apologize it's --

A. That's okay.

Q.182 - -- we are struggling all here a little.

A. As I say, now we are cooking with gas. Okay.

Q.183 - Well, we are not cooking with Orimulsion.

A. Okay.

Q.184 - In any event, the second column --

A. My little attempt at humour.

Q.185 - -- the third column is variable cost dollar per megawatt, and it appears to me that you used the variable cost $29.20 to do --

A. The breakeven analysis.

Q.186 - -- the breakeven?

A. That is correct.

Q.187 - And now when I go back to the other interrogatory that we pulled out, which is PI IR-1D --

A. Correct.

Q.188 - -- and I look at the -- and I am looking down in the second block of numbers, which starts coal, Orimulsion, Pepcoke --

A. Yes.

Q.189 - -- and you have monthly totals and the second line in there is heavy oil?

A. Yes, I have that. Right.

Q.190 - And if I go over on heavy oil and look at the very far right-hand side what I got is $72.04 per megawatt hour?

A. $74 --

Q.191 - 74 --

A. -- on top right.

Q.192 - Yes.

A. And then we change it a little bit and it comes to 74.60. But, yes, and that's the right ballpark.

Q.193 - Okay. And that 72.04 would be the fuel costs per megawatt hour at Coleson Cove at the time this particular analysis is done, am I correct?

A. That is correct.

Q.194 - Right.

A. But we are not using Orimulsion.

Q.195 - That's correct. And the point I am making is that as a result -- and perhaps to get to the point that we want to make, your study has taken into account for the lack of a better term, some of the -- the problems we had with the Orimulsion contract, correct?

A. Correct.

Q.196 - Right. You have done your analysis, that we are now paying -- using heavy fuel at the Coleson Cove plant, correct?

A. Oh, right. I mean I -- the actual cost --

Q.197 - That's what --

A. -- the actual cost that I am allocating has to be actual costs.

Q.198 - Yes. I appreciate that. And so because of this mistake, one of the results is -- and I go back on your evidence here briefly, as I understand it, you are allocating these fuels costs to the consumption patterns of the different classes base done their consumption in

the month of January?

A. For the oil, that's correct.

Q.199 - Right. So for 12 months of the year then, the consumption patterns of the residential class and they cost they take out of Coleson Cove are based on their consumption again in January, which would be probably the peak time of year for the residential class, correct?

A. That's correct. Right.

Q.200 - You would agree with me this wasn't a very good experiment in capital for fuel substitution at the end of the day?

MR. MORRISON: Mr. Chairman, I really don't think that's relevant to this discussion. There may be other forms in which it may be relevant, but I don't think it's relevant here.

CHAIRMAN: I think this is a relevant time to break for lunch. We will try and get back at quarter after 1:00. See how we make out.

(Recess - 12:00 p.m. - 1:15 p.m.)

CHAIRMAN: Good afternoon. Sorry about the lateness in the hour. We are going to try and wrap it up though at 3:00 o'clock thinking of the shorthand reporters. So anything preliminary? If not, go ahead, Mr. Hyslop.

MR. HYSLOP: Thank you, Mr. Chairman. -

1563 - Cross by Mr. Morrison -

Q.201 - Just a couple of other small points, Dr. Rosenberg. The first one, you mentioned Point Lepreau. And it's my understanding and perhaps yours, that there is going to refurbishment of the nuclear generator in apparently 2008-2009. That hasn't been factored in at all in your cost study, has it, Dr. Rosenberg?

A. No, those costs are not reflected in the company's revenue requirements at the present time.

Q.202 - Right. But just as a general statement that upon this being completed a couple of years now, it would tend to push the demand share of the fixed costs down, would that be generally a correct statement?

A. I really haven't done any analysis, so I can't answer that question.

Q.203 - I will leave it at then. I want to go back very briefly, if I could, to exhibit EGNB-2. And it's one of the exhibits we had out this morning. EGNB PI IR-1, and attachment D?

A. I have that. Again, this is the series of the 4 Excel spreadsheets?

Q.204 - Yes, And then we are looking at attachment D?

A. D?

Q.205 - D. D as in dog.

A. D as in dog. Yes, I have that.

Q.206 - And I want to focus, if I could, briefly on the three lines at the bottom of the first block of numbers at the top which refer to Purchase Power Frasier's, Edmundston and NUG's, Purchase Power Bayside Power and Purchase Power IOL?

A. Oh, at the top. Yes, I have that.

Q.207 - And dealing first with IOL and Frasier's, that suggests a number of megawatt hours to be purchased for all 12 months of the year?

A. Mmmm.

Q.208 - And when I look across that, it seems to suggest to me that the purchase of this power is at a pretty constant rate. It almost suggests that they are purchasing a good part of the power from each of those two sources?

A. Yes.

Q.209 - Yes. And for the Bayside Power, there seems to be some suggestion in looking at this that for five months of the year that we are purchasing this power from November through March. And it will look to be that we are buying a fairly large proportion of the generation from the Bayside Power?

A. I know a large portion, but it is certainly winter power.

Q.210 - Yes. When I also look at this table and I look at the

right-hand side, where it says, gas purchase power, that would be in the second block of numbers --

A. Yes.

Q.211 - -- and I go all the way over, it says per megawatt hour, I get $76.80?

A. That's correct.

Q.212 - And that would be for each megawatt hour of purchased power relating to those three items we just discussed?

A. That appears to be correct.

Q.213 - Yes, And again as I understand your methodology, you have allocated these fuel costs based on the fixed costs for oil plants and the demand allocator -- and this is the demand allocator of 95 percent, is that correct?

A. Correct.

Q.214 - Right. And what that means is you allocate these costs under your cost allocation methodology based essentially on who is buying the power in the month of January?

A. The capital cost of it?

Q.215 - Yes. And also would it not apply to these fuels costs for the --

A. Well, the fuel costs are allocated on a month-by-month basis.

Q.216 - Yes. And in the month that you are using to allocate

those, from my understanding of your methodology, is based on the month of January?

A. To allocate the duration question of a fixed cost.

Q.217 - Yes.

A. Yes, that's correct. And I don't know how much fixed costs are associated with those purchase power contracts.

Q.218 - Just so I figure out where I am going. So if I am a residential customer, I am getting assigned this high-priced generation every month based on your -- their contribution to the system peak, is that correct?

A. If it's high-priced generation, it's based on the system peak, that's correct.

Q.219 - Yes. Right. So, for example, if I am a residential customer, the amount of my July bill that I pay is based on my share of whatever I am purchasing in the January peak?

A. Well, you are allocated more peaking plant because you are a peaker load shape And so it's more economical to serve you with peaking plant, than it is to serve you with base load plant.

Q.220 - But going back to what we just looked at these numbers, doesn't the type or the amount of power and the continuity suggest that it is being used in a base load manner, Dr. Rosenberg?

A. Well, I treated the gas and oil purchases as one block of power. In other words, I didn't try to distinguish between this purchase power contract and that purchase power contract. That would be another element of granularity and I really don't think it would change the total results by very much.

MR. HYSLOP: Thank you very much, Dr. Rosenberg. That completes my cross examination. And I would certainly say the quiz went well.

WITNESS: Quite welcome.

MR. HYSLOP: Thank you.

CHAIRMAN: That's the shortest half hour on record, Mr. Hyslop.

MR. HYSLOP: Pardon me?

CHAIRMAN: That's the shortest half hour on record. Correct me, if I am wrong, Mr. Morrison, but it is now Disco?

MR. MORRISON: I believe that's correct.

CHAIRMAN: And then we will go to Mr. MacNutt.

MR. MORRISON: Just give me a moment.

CHAIRMAN: Oh, indeed. Take your time.

CROSS EXAMINATION BY MR. MORRISON:

Q.221 - Good afternoon, Dr. Rosenberg.

A. Good afternoon.

Q.222 - I am Terry Morrison. I will be asking you questions

on behalf of the Applicant, Disco. My condolences for the loss of your luggage and having to rely on Mr. MacDougall as your haberdasher. At least New Brunswick has finally got its second tie. So --

A. That was bad.

Q.223 - I know.

CHAIRMAN: I thought having to put up with Mr. Hyslop's reference to Scottish poetry was bad enough, Mr. Morrison.

A. I am not to be outdone.

Q.224 - Dr. Rosenberg, I just want to ask you a couple of questions on some things that came out this morning. I think it was in your cross examination -- I believe it was by Mr. Hyslop, you indicated that cost allocation studies are not perfect, is that correct?

A. That's correct.

Q.225 - But you did say that a cost allocation was the starting point for rate design, is that correct?

A. That's correct.

Q.226 - But there are other considerations that one must take into account when doing a rate design, is that correct?

A. Correct.

Q.227 - And one of those considerations would be gradualism, is that correct?

A. That's generally considered a valid consideration.

Q.228 - Under I believe it was cross examination again by -- no, it was by Mr. Gorman, I just want to clarify this, you said that you disagreed with all the other experts with respect to marginal costs. They are being proponents of the marginal cost approach. I just want to make sure that I am clear that you weren't referring to Mr. Ketchum in that regard, because Mr. Ketchum opposes marginal cost as well, is that correct?

A. I believe I was referring to the statements by Mr. Knecht and Messrs. Adelberg and Garwood.

Q.229 - Thank you. And under cross examination this morning by Mr. Hyslop, you made the statement that you were talking about system fixed costs. And I think you made the statement that system fixed costs are very stable over time?

A. Well, I think I was referring to the fixed costs, unless you build a new plant, generally don't change your depreciation rate, but normally the fixed costs are pretty much stable from year to year.

Q.230 - So you would agree with me that if there were no additions to the generation fleet that you would anticipate that system fixed costs would remain fairly stable?

A. Well, I mean you know, interest rates can go up or

down, if you float a new bond, in the case of investor-owned utility -- of course, that wouldn't be applicable to NB Power, but for investor-owned utility, they might get a different return on equity. So you do have changes like that. But they are not really drastic changes unless you build a new nuclear plant or something like that.

Q.231 - That's fair enough. Perhaps before I get into the meat of my cross examination, just so that we all have the same binders available, I will be referring to EGNB-1, EGNB-2 and A-3. And perhaps if we could turn up EGNB-1. And, of course, it's under the Enbridge Gas New Brunswick tab. And it's -- it would be your evidence Dr. Rosenberg?

A. Yes.

Q.232 - And if we can turn to page 7 of your evidence?

A. Yes.

Q.233 - And more particularly lines -- beginning at line 8 where it says -- and I think you are talking about the power purchase agreements?

A. Right.

Q.234 - And it says, moreover to obscure the tangible and measurable and authentic economic costs of the electric generation process would very likely frustrate the worthwhile objectives of cost based rates. For example, the Nuclearco contract is charged to Disco on a per

kilowatt hour basis. However, to ignore the essentially fixed nature of these costs and pretend they are variable would be clearly inappropriate for purposes of cost allocation and rate design, do you see that?

A. Yes, I do.

Q.235 - So I think the problem that you have identified here is that the Nuclearco PPA is priced on a kilowatt hour basis, while the underlying costs is essentially fixed, is that a fair statement?

A. It's priced on a per kilowatt hour basis, but unless the nuclear plant exceeds a certain capacity factor, in which case there is an incentive built in for the plant to run at a high capacity factor, it's a fixed dollar. So you could just as easily bill the Disco for X dollars per month, you know, without any reference to kwh, you know, for the first X million kilowatt hours --

Q.236 - And you would agree with me that a nuclear plant, I believe you said, is one that's very capital intensive, correct?

A. Yes, that's correct.

Q.237 - So do I take it from what you are saying that you believe that it would be inappropriate to ignore the fixed nature of the Nuclearco PPA for cost allocation and rate design purposes?

A. I agree with that entirely.

Q.238 - Now, you basically have -- if I can categorize your evidence at a very high level and I believe I am encapsulating it correctly, but if I understand your evidence on a high level is, you looked at what Disco did. You said, okay, Disco, you have adopted the Peaker Credit Method. You didn't do it right. In other words, there is some inconsistencies in the methodology -- the way you applied the methodology and therefore you undertook to do it right. Is that -- it may be a simplification, but is that the nub of your evidence?

A. I would agree with that.

Q.239 - And as a result of that you prepared an alternative CCAS, correct?

A. That's correct.

Q.240 - And the basis of your cost allocation study is the Equivalent Peaker Method, is that correct?

A. That is the philosophical basis, yes.

Q.241 - Right. And that's a capital substitution methodology, as I think you explained this morning?

A. That is absolutely correct.

Q.242 - And would you agree with me, Dr. Rosenberg, that essential to this type of analysis is determining the breakeven point of the various types of generation?

A. I would agree.

Q.243 - And in your cost allocation study in order to ascertain the break even point for the generation fleet, you examined I believe it was the alternative resource table analysis that was included in the February 2002 integrated resource plant?

A. I believe that is a correct reference, yes.

Q.244 - And not to put too fine a point on it, Dr. Rosenberg, but a good chunk of your report -- and I am going to say that's from pages -- between pages 10 and 36, what you are really doing is analyzing the New Brunswick Power generation costs, is that a fair statement?

A. That's a fair statement.

Q.245 - And in order to do that is it also fair to say that you have to have -- and I think you mentioned this morning, you have to have system planning information. The Equivalent Peaker Method, I believe you said this morning is the system planning-type analysis, correct?

A. All -- really all capital substitution methods are at their heart -- go harken back to system planning that we can have different types of generation. And they have different fixed costs for kw, and they have different variable costs for kwh.

Q.246 - So any capital substitution methodology whether it's

the equivalent Peaker or some other variant of that, you have to have access to that specific generation information, correct?

A. To do a fair job, yes.

Q.247 - And therefore, Dr. Rosenberg, you would agree with me that without current information about the resources used in generation, it would be very difficult, if not impossible, to properly apply the Equivalent Peaker Method, correct?

A. I don't think I would go that far. I think you have to distinguish between planning considerations and operating considerations. Certainly the actual -- your actual revenue requirement for a test year is based on operating considerations. And those are the costs that we have to be allocating.

On the other hand, when you -- in a sophisticated method, such as a capital substitution, I think you have to go back to planning. And the planning doesn't change from one month to the next. I mean, when you build a coal plant or a nuclear plant, you know, you expect it to have a 20 year to 40 year life. And so I think that planning considerations do give you a pretty good picture of who is causing what cost on the utility.

Q.248 - But you need that information -- you need that system

planning information to do the analysis?

A. Right. And that's certainly one of the reasons we requested that type of information in the discovery phase.

Q.249 - Now if I am correct, during the direct examination this morning by Mr. MacDougall, you gave a number of reasons why you believe the Equivalent Peaker Method was the appropriate methodology to use in this case, correct?

A. Given the history of New Brunswick, yes.

Q.250 - Correct. And two of those reasons stuck out in my mind, Dr. Rosenberg. And I think the first one -- I think you used the analogy, if it walks like a duck and talks like a duck, it's a duck. But you made the -- and one of the reasons, and I am going to suggest to you, and you can correct me if I am wrong, and perhaps the primary reason why you believe that the Equivalent Peaker Method was appropriate in this case is because you don't -- you do not believe that NB Power, the utility, is really unbundled, is that correct?

A. Well, I believe I -- Mr. MacDougall examined me, I gave a series of reasons why I felt -- that the cost -- that the -- there is a threshold question. And the threshold question is do we simply take the PPAs and look at how they bill for Disco in some cases and in other cases, we don't look at how they bill. In other words, we

will use cost accounting, except where we don't use cost accounting. Or we will use cost causation except when we don't use cost causation.

My recollection was that we submitted an interrogatory to the company. We said in the long run, don't the PPAs have to ultimately reflect the physical and actual costs of the generating companies? And I think the answer was yes. And so I think that you have to -- if you are trying to establish a nexus between customer usage and cost causation, then you actually have to look at the costs. And that's why I said, okay, the threshold question is do we look at just the billing or do we look at cost causation? And once I answer that and I say, okay, if I look at cost causation, what method am I going to use, fixed variable or capital substitution? And based upon the history --

Q.251 - No. And I understand the conclusion that you reached. What I am trying to get at, Dr. Rosenberg, is that what you got into this morning, which really wasn't in your evidence and that's fine. But the rationale you used in basically answering that threshold question. And if I recall your direct testimony this morning, I think there were eight reasons. But two of them that struck me were first that basically this is an integrated utility. It's

not unbundled. And secondly, that the Board in its 1992 decision at least implicity recognized the philosophy of capital substitution, is that fair?

A. I think that's fair.

Q.252 - So would you agree with me, Dr. Rosenberg, that if nether of those two criteria were met, would you still be advocating use of the Peaker Credit methodology?

A. If neither of those conditions were met? Well, you are asking obviously a hypothetical.

Q.253 - Absolutely.

A. It was always tough to answer hypotheticals. If I had just come in totally cold and was not aware of the 1992 decision, if I decided to use cost causation, okay, then I would use the fixed variable approach. It's simple. It's widely used. You don't have to look at system planning. It's very simple. And I believe it gives a reasonable approach.

Now getting back to the other question, if Disco were really buying their generation from a lot of places and they were negotiating a contract here and negotiating a contract here, then I -- you know, I would tend to give more weight to their power purchase costs, because they really are power purchase costs. But the way I saw the situation, the PPAs were almost a convenience of you know

how to functionally unbundle without really unbundling. And -
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Q.254 - I am sure that is going to be a point of some argument at some point in time.

A. Well, it could be. But if you are not actually -- if you are not actually looking at -- I mean let's say the PPA gives no -- absolutely no consideration to seasonality, well then the customers are going to say -- and you transfer that into the ratemaking process and say we will give no considerations to seasonality, then the consumer is going to say well, it doesn't make any difference whether I use gas in December or whether I use gas in April. I mean, the electricity in December or electricity in April, it makes no difference. But it does make a difference. And ultimately if the costs go up the PPAs are going to have to change too.

It's not conducive -- unless you actually look at the underlying costs and peel back the layer and see what's really going on, it's really not conducive to efficiency and to all the things that I think this province really wants to do.

Q.255 - Well, you have been I think in this field for what 24 years, I believe?

A. Almost, yes.

Q.256 - And I understand -- I mean you have done a number of cost allocation studies and been an expert witness numerous times. And I think I overhead you saying you have been cross examined hundreds of times. And I understand that you have done some work in the PJM system, is that correct?

A. I have testified in Pennslyvania. I testified in the restructuring cases in New Jersey. Those are --

Q.257 - In the PJM systems?

A. Yes. Delaware. I have done some work in Delaware, so yes.

Q.258 - So you have been involved -- I believe you might have been involved is it the Delmarva matter?

A. Delmarva, yes.

Q.259 - And I understand that the PJM system is an independent operator that operates in Pennslyvania and New Jersey, Maryland and Ohio and maybe a couple of other states?

A. I think they actually have a bigger footprint there now. They actually -- there is a PJM South. Dominion Resources just joined them. So the footprint is I think has recently gotten -- American Electric Power just joined the system. So the footprint is -- I don't know the exact footprint, but I think it is pretty big.

Q.260 - Right. And in the PJM system, I understand that let's

say a distribution company obtains power from a number of generators, independent generators and the mechanism is generally power supply agreements, is that correct?

A. No, not entirely.

Q.261 - No.

A. You do -- Delmarva, for example, when they restructured in Delaware, they divested all their generation. So you take a utility like Delmarva, they are entirely dependent upon purchase power.

Q.262 - So that they are now only a distribution --

A. They are basically only a wires company.

Q.263 - Right.

A. Right. That's correct.

Q.264 - So they would buy their power under purchase power agreements --

A. Under a purchase power --

Q.265 - -- from a number --

A. Right. I mean it's up to them. They could buy a purchase power agreement. They could buy it on the spot market. That's up to their discretion.

Q.266 - So if you were doing a cost allocation study of Delmarva or another distribution company, the PJM system, you would not use the Peaker Credit Method, would you?

A. No, I would not. As a matter of fact, Delmarva just

filed a rate case, and there is no generation at all in the rate case. It's simply a wires case, because they just want to get the wires correct.

Q.267 - Right. That's because it's a -- purely a distribution company?

A. It's purely a distribution company.

Q.268 - And you wouldn't have access to the generation costs in any event to do a cost allocation study based on the Peaker Credit Method?

A. Yes, that's true.

Q.269 - So if you are doing a cost allocation study for Delmarva or another strictly distribution company in the PJM system, you would be looking at their purchase power costs, correct, through their purchase power agreements?

A. Well, that's right. I mean they have what's called standard offer service.

Q.270 - Correct.

A. And the standard offer service or set based without regard to an embedded cost allocation study.

Q.271 - But their price driver would be their purchase power cost?

A. Their price driver would be their purchase power cost, that's correct. For their standard -- for supply, yes.

Q.272 - Correct. Could you turn to page 39, Dr. Rosenberg?

A. 39?

Q.273 - 39, yes. And it's really the first paragraph on that page. And it talks about I guess the relative complexity of your approach as opposed to Disco's approach, correct?

A. Yes.

Q.274 - And if I understand your evidence, you would agree that your generation cost analysis approach is more complex and requires significantly more data than Disco's approach, correct?

A. That's true.

Q.275 - Now, Mr. Gorman -- I am going to ask you to turn up EGNB-1 again. And it's the schedules that are attached to your evidence, which are -- no, I believe it's -- it's still in the schedule attached to Dr. Rosenberg's evidence. And Mr. Gorman took you there this morning. It's schedules AR-1 -- exhibit AR-1, schedule 1 and schedule 2. And looking at both those schedules, Dr. Rosenberg, it appears that the most noticeable I guess impact of applying your methodology as opposed to Disco's methodology is that the residential class is allocated a bit more cost and the large industrial class is allocated a bit less cost, is that a fair --

A. The residential class is allocated a bit more cost, that's correct. And what was your second --

Q.276 - And the large industrial is allocated a bit less cost?
A. Yes. But there were some other differences as well.
Q.277 - But those are probably the most striking, if you will?
A. Perhaps, yes.
Q.278 - Other than that, and I know that you used two entirely different methodologies, would you agree that for the most part your results are fairly similar?
A. Well, the numbers, of course, speak for themselves. I mean, it's a fact of life that when you do different cost of service studies, like for example, if you are talking about how much cost shall we classify as demand related versus energy related? Okay. That's a big decision. But if you have a class whose load factor is the same as the system average load factor, it doesn't make any difference to them. Because they have the system average load factor. They don't care how you classify. It only affects classes that -- that decision only affects classes that are -- either have a higher than average system load factor or a lower than average system load factor.

Likewise when you allocate fuel costs, if you have a class that uses the same as the system in winter and in non-winter, again, that class is going to be indifferent as to whether you make a differential fuel allocation.
Q.279 - And that's because of the characteristics of the

customer base of a particular utility, correct?

A. Right. So when you make changes such as I made, where it's going to show up are going to be classes that have either a very large load factor difference than the system average or very different usage shape than a system average.

Q.280 - And in this case that's primarily the heating class customers, both general service and residential, correct?

A. That's correct. That is correct.

Q.281 - But overall, despite the fact that there is two methodologies that have been used, the numbers come out fairly symmetrically or fairly closely, correct? The numbers are the numbers, right?

A. The numbers are the numbers, yes.

Q.282 - Fair enough. If I can ask you to turn back to page 39 again of your evidence, and I think you alluded to it just a few moments ago, you said that if you -- if for whatever reason you weren't going to use the Peaker Credit Methodology -- and again it's in the first seven lines of that first paragraph?

A. Yes.

Q.283 - You would use this straight fixed variable approach? Correct?

A. Yes.

Q.284 - And in this case, in the case of New Brunswick, would you agree with me that if you use the straight fixed variable approach, that the result would be that more costs would be allocated to the peak users?

A. Yes. As a matter of fact, I think I did a sensitivity run. I actually looked at a more of a traditional run and, yes, there were more -- even more costs allocated to the peak users than under my method.

Q.285 - Right. And again in New Brunswick, when we talk about the peak users, we are primarily talking about residential heating class and the general service II class, correct?

A. That's correct.

Q.286 - Does it -- that's heat drive the peak in New Brunswick?

A. Absolutely.

Q.287 - I just want to get back a little bit more on the use of the Peaker Credit System for a moment, Dr. Rosenberg. In your direct evidence this morning, you talked about -- you know, the basis is cost causation, correct?

A. Correct.

Q.288 - And you stated that you believed you should look at NB Power's generation costs. And the reason you looked at NB Power's generation costs is that you don't view the utility as really being functionally unbundled, correct?

A. Well, those are the cost that are impacted. I mean when somebody puts their light switch on or raises or lowers their thermostat in New Brunswick, they are affecting New Brunswick Power's costs. They are not affecting American Electric Power's costs.

Q.289 - So it's your view that it's really the underlying generation costs that are driving Disco's costs, correct?

A. Correct.

Q.290 - But you are aware that this is an application by Disco?

A. I am aware of that.

Q.291 - And I am assuming that you wouldn't agree with me then that what drives Disco's costs, as opposed to NB Power's costs or the old utilities costs, is the PPA pricing?

A. No, not really. I think ultimately it's got to be the actual cost of the generation.

Q.292 - So in short you have for want of a better word separated the PPAs from the cost causation?

A. I have tried to look behind the PPAs -- --

Q.293 - Right.

A. -- to the actual costs, yes.

Q.294 - I would like to turn now to the question of functionalization and classification of the distribution costs, Dr. Rosenberg?

A. Distribution costs?
Q.295 - Yes.
A. It's not an area that I believe I addressed in my testimony.
Q.296 - I know. And that's why I am raising it. I note when I went through your report, that your report doesn't address in any way functionalization and classification of Disco's distribution costs, correct?
A. That's correct.
Q.297 - You just don't deal with it?
A. That is correct. It was not on my plate, so to speak.,
Q.298 - And if I can get you to turn to exhibit A-3?
A. A-3. I have that.
Q.299 - A-3. And it's the evidence of Malcolm Ketchum.
A. Right.
Q.300 - And if you look at page 14 --
A. I have Mr. Marois, Mr. Larlee. I am looking for Mr. Ketchum's.
Q.301 - Mr. Ketchum's is tucked in behind Mr. Larlee, I believe.
A. Tucked behind Mr. Larlee. Okay. I have Mr. Larlee.
MR. MACDOUGALL: It's the very last tab in the binder, I believe, Dr. Rosenberg.

WITNESS: Oh, okay. They stuck you all the way at the back, Malcolm. But you know what, there is nothing behind that last tab in my book. I think I brought Mr. Ketchum's evidence with me. Well, let me see if I have it here so you can have yours, too.

CHAIRMAN: Did you provide those volumes?

MR. MORRISON: Me, personally, Mr. Chairman?

CHAIRMAN: Yes.

WITNESS: I have Mr. Ketchum's evidence -- I brought it with me, but --

MR. MORRISON: Mr. MacDougall asked us to provide the binders up there. So they are all mixed up.

Q.302 - In any event, if you could turn to page 14?

A. 14 of Mr. Ketchum's testimony.

Q.303 - Right. And there is a table there. And it shows the effects on revenue to cost ratios if you made changes to the functionalization and classification of distribution costs?

A. Yes.

Q.304 - And would you agree that when you look at that table that revenue to cost ratios -- the revenue to cost ratios are not particularly sensitive to changes in functionalization and classification in this case?

A. This table shows a relatively small change, yes.

Q.305 - And what I am getting at, Dr. Rosenberg, is your evidence focuses in a large part on the generation costs, if not entirely?

A. Yes, it does.

Q.306 - And is that because the generation cost classification is much more important in terms of its impact?

A. Yes. Well, yes, as a matter of fact, one of the reasons I focused on that -- there is several reasons. One, when I did a brief review of the company's cost of service study, the area of the classification and allocation of the generation cost is what struck me most is where I have a bone to pick, okay. I really didn't have much of a bone to pick in the other areas, so okay, the first reason -- but the second reason was because of the magnitude --

\Q.307 - Of course.

A. -- the generation and costs sort of overwhelmed the distribution costs.

Q.308 - Right. In other words, in the big scheme of things, fooling with the classification and functionalization of distribution costs isn't going to have a tremendous impact on the outcome?

A. No, it's not.

Q.309 - And is it fair to say, Dr. Rosenberg, the fact that

you didn't address the functionalization and classification, can I take it from that you felt that Disco's approach to functionalization and classification was not unreasonable?

A. Yes, I think that's a fair statement.

Q.310 - Now, I want to turn now, Dr. Rosenberg, to some of your specific rate proposals?

A. Yes.

Q.311 - And in particular I guess I will start with -- well, perhaps the most significant of your proposals is the proposal for seasonal rates?

A. Okay.

Q.312 - And you are proposing two seasonal rates, one for residential and one for general service, correct?

A. That is correct.

Q.313 - So let's go with the residential seasonal rate proposal first. And I would like to turn back to your evidence again, which is EGNB-1. And that's at page 10 of your evidence?

A. Yes.

Q.314 - And if you look at sort of the last paragraph beginning at I think line 16, yes, that whole question. And in there you state that my own analysis of NB Power date indicates that NP Power's fuel costs are up to $10 to

$14 per megawatt hour higher in the winter months than in the spring and summer months, is that correct?

A. That's correct. I believe I supplied that work paper response to some discovery.l

Q.315 - And would you agree that that translates into a differential of between 1 and 1.4 cents --

A. Yes.

Q.316 - -- kilowatt hour?

A. $10 per megawatt hour is 1 cent per kilowatt hour and $14 per megawatt hour is 1.4 cents. You divide it by 10.

Q.317 - And if we turn to page 45 of your evidence, I believe it's at page 45 where the specifics of your seasonal rate proposal are set out --

A. Yes.

Q.318 - -- under your proposal there, there would be a winter kilowatt charge of 9.93 cents?

A. That's correct.

Q.319 - And a non-kilowatt hour charge of 7.8 cents, correct?

A. That is correct.

Q.320 - And you would agree with what you are proposing would result in a winter-summer differential for the residential heating customers of 2.85 cents, about 3 cents?

A. Yes. 2.85, yes. That's correct.

Q.321 - So we have a marginal cost difference between winter

and summer, which is what 1 to 1.4 cents. And you are proposing a seasonal rate, which has a differential of almost 3 cents per kilowatt hour, correct?

A. Well, I think you said marginal costs.

Q.322 - Right.

A. I don't believe the 10 to 14 was marginal. I think those were the difference in the average fuel costs between one month and another month.

Q.323 - So what is the basis for your recommendation?

A. The basis for my --

Q.324 - Have you done an actual cost calculation of that 3 cents?

A. Yes. Well, that's an excellent question. As a matter of fact, I think imposed the question like that to me in discovery. So if you wouldn't mind, I might as well go to that question. And I believe it came from the Disco. Yes, I think it was Disco's IR-10. And the first question was, would Dr. Rosenberg agree that his seasonal rate design is not cost-based given that he suggests on page 44, line 20 that the winter, non-winter differential is 1 cent. It's really 1 to 1.4 cents. And that his proposal on the top of page 46 is for an approximately 3 cent -- and it's really 2.85 cents. And then it said if the answer is yes, please explain the justification? Well, as

you might have expected I did not agree that it is not cost-based. The differential that I spoke of before, the $10 and the $14, that relates just to fuel. That's totally fuel. And under the equivalent Peaker Method, capacity costs are also considered duration-related.

So consequently a larger portion of those duration-related capacity costs should also be allocated in the winter months. So you have a differential base just on the fuel costs. You have got a second differential based upon these duration-related capacity costs. And finally, they are talking about the residential class. And the residential class does not have a demand charge. They don't have demand meters. You can't give them a demand charge.

Q.325 - So it's a capacity cost --

A. So therefore -- exactly. So, therefore, you have to put some capacity costs in there as well to give that signal. It's the only way you can give that signal.

Q.326 - No, I understand that, Dr. Rosenberg. But where is the calculation for that capacity cost?

A. Well, the proof of the pudding is that when is all said and done, the rate design that I am proposing, doesn't even equalize the revenue to cost ratios between the heating class -- the heating customers and the

non-heating customers. So if you look at that, you say okay let's do everything Rosenberg says we should do and put in this 3 -- 2.85 cent differential, but when all is said is done, we run the cost of service study and the heating class still is still -- has a lower revenue to cost ratio than the non-heating class. So there is the proof of the pudding that perhaps I didn't go far enough than 2.85 cents.

Q.327 - But the point that I am trying to make Dr. Rosenberg is that you didn't build this right up from a cost calculation, didn't you? If I look at your evidence eon the bottom of page 45, you basically solved, correct?

A. Correct.

Q.328 - So it wasn't a calculation, per se, correct?

A. There are various ways to come up with a seasonal rate. And what I did was I tried to have certain objectives that I was trying to meet and that I solved to reach those objectives. But when you are all finished with that, Mr. Morrison, you then have to go back and say, okay, does my result make sense? Is my result more cost based? And then you look at your revenue to cost ratios and see whether or not you have done a good job. And that's what I did.

Q.329 - That's fair enough. I am going to go now to EGNB-2.

And it's Disco IR 11. EGNB-2, IR 11. And if you turn into the first two -- the third and fourth pages of the attachment, Dr. Rosenberg. One is the typical monthly load for a single residential customer, do you see that?'

A. Actually, I don't -- you know --

Q.330 - I guess I did it again.

A. -- I should have taken Mr. MacDougall's copy of the response.

MR. MACDOUGALL: I could certainly do that, Mr. Chair.

A. Okay. I have that.

Q.331 - If you can turn to the next page, which response is -- customer impact analysis using recommended rate design, do you see that?

A. Yes.

Q.332 - And you did do some customer impact analysis with respect to this seasonal rate for residential customers, correct?

A. Yes, I did.

Q.333 - And if I understand your evidence, the average customer impact of your proposed seasonal rate is 15.8 percent?

A. Compared to present rates, yes.

Q.334 - Now on the preceding page, you have some monthly data there, but you did not show the percentage impact on a

monthly basis, did you?

A. That is correct.

Q.335 - I believe I have given something to Mr. MacDougall before the break at lunch hour --

A. Yes.

Q.336 - -- and I am assuming he gave that to you?

A. Yes, he did.

MR. MORRISON: And I am going to ask that it be marked as an exhibit. And basically what it is, Mr. Chairman, we took Dr. Rosenberg's numbers and we solved -- well, not solved, we calculated the percentage impact on a monthly basis for the -- as to the impact of the seasonal, residential rate that he proposes. And I will just have these marked.

A. Does this now have an exhibit number?

CHAIRMAN: It is coming, sir. It is now A-46.

MR. MORRISON: A-46.

Q.337 - Dr. Rosenberg, looking at exhibit A-46, you will see that using basically your analysis, your numbers, we calculated a percentage difference in seasonal rate on a monthly basis. Do you see that?

A. Yes, I do.

Q.338 - And the -- while the average impact across the year would be 15.8 percent --

A. I'm glad you corroborated my number.

Q.339 - We did indeed. There are months where the impact on customers, for example in January is close to 39 percent. Correct?

A. Right.

Q.340 - And according to this, the average impact from November to March would be 35 percent. Correct?

A. That's what the numbers show, yes.

Q.341 - So that while you are correct in that the average impact is 15.8 percent, there are months in the year when customers would receive or would see an impact in their bill of upwards of 35 percent? Would you agree with that?

A. I would agree with that. Would you like me to comment on that?

Q.342 - I'm sure I can't stop you.

A. That's where you're sure. First of all, this comparison is between the rates that I was proposing and the current rates. Okay.

Q.343 - That's correct.

A. And those are based on two different revenue requirements. Okay. So if you really want to just isolate on the impact of the rate design, okay, not the revenue requirement, because you know, when you came in in April you wanted an increase, a 4 point something percent increase. So if you really just want to focus on the

impact of my recommendations on rate design, I think a fairer comparison would be between the rates I am proposing and the rates that for example, NB Power was proposing, that Disco was proposing back in April. So that's number one.

Number two, there is no question that my rate is seasonal. I mean, seasonal rate means your winter rates are going to go up. That is -- we are trying to induce a certain reaction to that. We want customers to insulate their homes or maybe put in a more efficient boiler. You know, whatever.

So these comparisons really don't assume that the customer is going to change its usage pattern in reaction to those rates. That is number two.

Number three, I know a lot of utilities have what they call budget billing. So if you think that, you know, the increase is too much, you can still say, you know, Mr. Consumer or Mrs. Consumer, you can pay us more on even matter, but the consumer is still getting the right price signal. The consumer is still getting the signal that hey, it cost a lot more in the winter than it does in the summer even though I am paying it over an even amount. So that's really what I wanted to say.

Q.344 - And you would agree with me that these impacts are

significant? If I understand you correctly, Dr. Rosenberg, that is exactly what you want. Correct?

A. Correct.

Q.345 - Because you want to send a price signal, correct?

A. That's correct.

Q.346 - So what it really comes down to then is a question of competing considerations, wouldn't you agree, between gradualism and customer impact versus sending the appropriate price signal. Would you agree with that?

A. I think that is a fair statement.

Q.347 - I would like to turn now to your general service seasonal rate proposal. I believe we can go back to page 47 of your evidence, which is EGNB-1.

A. Yes.

Q.348 - Now if I understand how you approach this, Dr. Rosenberg, and I hope I have it right.

A. I hope I have it right.

Q.349 - You have combined the general service I and II classes --

A. That is correct.

Q.350 - -- together? And then you split the combined class seasonally, winter and non-winter, correct?

A. That is correct.

Q.351 - And you are proposing a winter demand charge of $8.34

a kilowatt hour -- sorry, kilowatt, not kilowatt hour?

A. Yes.

Q.352 - And would you agree with me that the winter demand charge is approximately 70 percent higher than the summer demand charge?

A. Under my proposal?

Q.353 - Yes.

A. Yes, that's about right.

Q.354 - Okay. And the second aspect of your proposal is to institute a winter, non-winter energy charge. Correct?

A. That is correct.

Q.355 - Okay. And the winter charge you selected is 10 cents per kilowatt hour.

A. That's correct.

Q.356 - Right. And would you agree with me that this would result in an energy price differential between winter and non-winter of 4.5 cents per kilowatt hour?

A. Approximately, yes.

Q.357 - And if I go to page 48 of your evidence beginning at lines -- I guess it's line 10 and 11, if I understand your evidence, you set the winter energy charge at 10 cents per kilowatt hour judgmentally? That was a judgment call on your part, correct?

A. That's correct. There is a lot of judgment involved

in rate design.

Q.358 - Okay. So other than the judgment, is there any cost basis for the differential found in the seasonal rate that you are proposing for general service?

A. Well I actually pose that question on page 48 of my evidence as to why I did choose 10 cents. And I did that because it produced a number of reasonable results.

Q.359 - So it was a judgement. And I am not criticizing the fact that it --

A. The reason you have to do judgement is because when you look at just the cost of service study all by itself, there is nothing there that can say oh, the winter charge will be this, the summer charge will be that. The winter demand charge will be this. It is not geared to provide that type of information.

Q.360 - Okay.

A. So you have to use some judgment.

Q.361 - So you, using your judgment, selected 10 cents a kilowatt hour?

A. Right. Then you have to test your judgment to see if it produces reasonable results.

Q.362 - And in your view it produces a reasonable result?

A. That's correct.

Q.363 - But you would agree with me, Dr. Rosenberg, that there

would be others who may differ with your judgment in that regard?

A. Well then they would have to show why they thought their results were more reasonable.

Q.364 - I want to turn now to the next page of your evidence. It is lines 11 and 12.

A. Yes.

Q.365 - And it is talking about first -- the general service II revenue requirement for the same level proposed by Disco.

A. Mmmm.

Q.366 - So the next sentence that I want to draw your attention to. Second, the general service I class would receive a decrease so there should not be a concern about gradualism for those customers.

A. It certainly mitigates the concern.

Q.367 - Okay. Now if I told you, Dr. Rosenberg, that not all general service I customers would receive a rate decrease under your winter proposal, would have any reason to disagree with that?

A. No, I would not.

Q.368 - Okay. And if I told you that approximately 3,000 general service I customers would in fact see an increase in their winter time bills, would you have any reason

disagree with that?

A. You said in the winter time bills?

Q.369 - Yes.

A. Well certainly it's -- no, that wouldn't surprise me either although I haven't done that analysis because we are trying to raise the winter bills.

Q.370 - Right. And you are aware, Dr. Rosenberg, that close to 60 percent of Disco's customers are heat customers, that heat with electricity?

A. Yes.

Q.371 - And did you do any customer impact analysis to see how individual customers might be impacted by this proposal, this general service proposal?

A. Not on an individual customer basis.

Q.372 - Okay. And if I told you, Dr. Rosenberg, that some general service II customers would see impacts of up to 50 percent in some winter months, would you have any reason to disagree with that proposal?

A. In some winter months, I would not have any basis to disagree with you on that.

Q.373 - Now I want to go to the last area, which is the -- your proposal with respect to standby rates.

A. Yes.

Q.374 - And if we can go to EGNB-2. And it is Disco IR --

A. Oh where the --

Q.375 - Yes.

A. -- interrogatories. Yes.

Q.376 - Disco IR-12, way at the back. I think it's the last response in the binder.

A. Yes, I have that.

Q.377 - And we put a question to you about whether you -- well I will pose the question. Is Dr. Rosenberg aware that cogeneration exists in New Brunswick and that Disco currently provides non-firm backup under the interruptible rate to industrial self-generators? And your response to that was no, Dr. Rosenberg, is that correct?

A. Yes, that's the truth.

Q.378 - So at the time that you prepared your evidence, you were not aware that Disco was offering interruptible rate to cogeneration customers. Is that fair?

A. That is correct.

Q.379 - Finally Dr. Rosenberg, if I step back, looking at the big picture here, when you look at your proposals with respect to seasonal rates for both residential and general service, is it fair to say that your proposals will make electric energy significantly more costly in the winter heating season than it is currently?

A. It will make it more costly to the customers because

it is more costly to the utility. And that is the essence of cost causation.

Q.380 - Right.

A. When it is costly to the utility it should be costly to the customer. What is non-costly to the utility should save the customer.

Q.381 - And one of the outcomes of that type of price signal, if you will, I think you mentioned this morning, is the opportunity for fuel switching. Correct?

A. That is correct.

Q.382 - And it would make natural gas more attractive, for example?

A. Depending upon the price of natural gas.

MR. MORRISON: Thank you, Dr. Rosenberg. Those are all my questions, Mr. Chairman.

CHAIRMAN: Thank you, Mr. Morrison. I know that Mr. MacNutt would want me to break for the day now. Mr. MacNutt concurred. So we will rise now and come back at 9:15 tomorrow morning. Thank you.

(Adjourned)

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