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 - Revenue Requirement

Delta Hotel, Saint John, N.B.
February 22nd 2006

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Delta Hotel, Saint John, N.B.
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CHAIRMAN: Good morning, ladies and gentlemen. Here beginneth day 46.

Could I have appearances, please, first of all for the Applicant?

MR. MORRISON: Good morning, Mr. Chairman, Commissioners. Terry Morrison and David Hashey for the Applicant. With us at counsel table is Lori Clark.

And on my far left it is my pleasure to introduce Ryan Burgoyne who is an articling student with our firm, Mr. Chairman.

CHAIRMAN: Welcome, Mr. Burgoyne. I presume that you will be handling the examination this morning.

Thanks, Mr. Morrison. Canadian Manufacturers and Exporters?

MR. LAWSON: Good morning, Mr. Chairman and Commissioners. Gary Lawson appearing with David Plante today.

CHAIRMAN: Thanks, Mr. Lawson. Conservation Council is not here. Enbridge Gas New Brunswick?

MR. MACDOUGALL: David MacDougall, Mr. Chair and Commissioners, for Enbridge Gas New Brunswick.

CHAIRMAN: Thank you, Mr. MacDougall. And for the Irving Group of companies? Mr. Booker?

MR. BOOKER: Good morning. Andrew Booker for JDI.

CHAIRMAN: Good morning, Mr. Booker. And Mr. Gillis is not here. Rogers is not here. Some concern was expressed before we came in to make certain that Rogers was aware that next Tuesday was set aside for continuation of their evidence. There is no problem there?

MR. HASHEY: The schedule has been sent out to them. That was understood. But we will make absolutely sure today. But I'm positive there is no problem.

CHAIRMAN: Okay. Thanks, Mr. Hashey. And no self-represented individuals. They have really given up on us, haven't they. Municipal Utilities?

MR. GORMAN: Good morning, Mr. Chairman and Commissioners. Raymond Gorman appearing on behalf of the Municipal Utilities.

And this morning at our table from the City of Edmundston I have Michael Couturier, and from Saint John Energy Eric Marr and Dana Young.

CHAIRMAN: Thanks, Mr. Gorman. Vibrant Communities is not here yet. And the Public Intervenor?

MR. HYSLOP: Peter Hyslop with Carol Power this morning, Mr. Chair.

CHAIRMAN: Thanks, Mr. Hyslop. And again if are there any Informal Intervenors want to go on the record let me know. But I don't see any.

Mr. MacNutt, whom do you have with you this morning?

MR. MACNUTT: I have with me this morning, Mr. Chairman, Doug Goss, Senior Adviser, John Lawton, Adviser, Jim Easson, John Murphy and Andrew Logan, Consultant and Adviser.

CHAIRMAN: Thank you, Mr. MacNutt. Preliminary matters?

MR. MORRISON: Yes, Mr. Chairman. I have three undertaking responses to have entered.

The first is undertaking number 2 from February 20th requested by Mr. Coon. It is in reference to an IR dealing with the as-built cost estimate for Point Lepreau.

CHAIRMAN: My records indicate that is A-118.

MR. MORRISON: The next one, Mr. Chairman, is undertaking number 3 from February 20th requested by Mr. Gorman regarding whether there have been any changes in the minutes of the Operating Committee meetings.

CHAIRMAN: And that will be A-119.

MR. MORRISON: And finally, Mr. Chairman, is undertaking number 5 from February 20th from Mr. Hyslop. And again that deals with the minutes of the Operating Committee.

CHAIRMAN: And that is A-120. Any other preliminaries? Mr. Morrison?

MR. MORRISON: No, Mr. Chairman.

CHAIRMAN: Mr. MacDougall?

MR. MACDOUGALL: Yes, Mr. Chair. Mrs. Légère said it would be appropriate for Enbridge Gas New Brunswick to enter the testimony that was filed on their behalf on February 17th. She has copies of that. And I would like to enter those two documents as exhibits now.

The first document, Mr. Chair, would be the written Direct Testimony of Andrew J. Harrington and Shelley L. Black dated February 17th.

CHAIRMAN: That is EGNB-4.

MR. MACDOUGALL: And Mr. Chair, these documents have been already provided to all other parties to the proceeding.

CHAIRMAN: Just a moment. I have marked something wrong here.

MR. MACDOUGALL: The first one, Mr. Chair, would be the testimony of Andrew J. Harrington and Shelley L. Black.

CHAIRMAN: Yes. And that is 4.

MR. MACDOUGALL: Okay. And the second one is the Direct Testimony of Alan Rosenberg.

CHAIRMAN: EGNB-5 is the Direct Testimony of Alan Rosenberg.

MR. MACDOUGALL: Thank you very much, Mr. Chair. That is all the preliminary matters.

CHAIRMAN: Thank you. Any other preliminary matters? Okay. Time for the panel to ask its questions.

BY THE BOARD:

MR. BELL: Good morning, panel. Starting with Ms. MacFarlane. With regard to the audit of the fuel hedging program which I understand you understood to provide, I just had a question with regard to that. Were there any recommendations that followed from that audit that were provided to management?

MS. MACFARLANE: Yes, there were.

MR. BELL: Were they included with the report that will be provided to us?

MS. MACFARLANE: Yes.

MR. BELL: Thank you. My next question is with regard to the PROMOD program and I was wondering, is that owned by Genco or is that licensed from a third party?

MR. KENNEDY: It's licensed through a third party with the Genco holding the license.

MR. BELL: And do they do software maintenance on this program on an annual basis, or is the source code something that you have access to?

MS. MACFARLANE: We will have to check that, but I doubt it is something that we are actually changing the software on. I suspect that there are upgrades periodically done based on submissions from the supplier.

MR. BELL: Okay. So that would be the only time it would be changed --

MS. MACFARLANE: Yes.

MR. BELL: -- is on an upgrade.

MS. MACFARLANE: That's correct.

MR. BELL: And you don't have access to the source code.

MS. MACFARLANE: No.

MR. BELL: Okay. Finally, in regards to the precipitator project at Coleson Cove, were costs for Genco and Disco's contract administration, supervision as well as interest during that construction capitalized?

MS. MACFARLANE: Yes.

MR. BELL: Thank you very much.

MS. MACFARLANE: Perhaps, Mr. Chair, while we are on that topic, I had made an error yesterday. I had been asked about the precipitator, where the revenues for the sale of gypsum were, and I indicated that they were netted off the capacity payment. In fact when I checked last night they are netted off the contracted energy price.

MS. LEBLANC-BIRD: Good morning, Panel. Mr. Peaco, I heard several terms used Monday in relation to the La Capra reports tendered in this proceeding, including prudency review, reasonableness review, technical audit, audit and independent audit.

Firstly, how does a company such as Disco who is intending to retain the services of La Capra Associates determine what type of report or review they might require in a given situation?

MR. PEACO: You are asking me to make a judgment of what Disco would choose to do?

MS. LEBLANC-BIRD: How would somebody in Disco's position -- a company such as Disco --

MR. PEACO: Just hypothetically?

MS. LEBLANC-BIRD: -- determine what sort of report they might require from a company such as La Capra?

MR. PEACO: Sure. Well it all depends on the objectives that they are pursuing. I think in this particular instance Disco is clearly looking for somebody from outside of their organization to come in and do a -- a second set of eyes -- look at their analysis. That was the objective they had particularly with respect to presenting the results of that information for your information here today.

There are other ways -- other reviews that a company might do depending upon the purposes that they have.

One term we mentioned was prudency review. The prudency issue came up yesterday but in a different context. Our analysis clearly was not a prudency review. I think that was in an exchange I had with Mr. Hyslop perhaps yesterday.

A prudency review would be something different than an audit or a technical review of calculations such as we did.

MS. LEBLANC-BIRD: I guess my question -- the second part of that is how would someone know what it is that they would be looking for, whether they would be looking for a prudency review or a reasonableness review or a technical audit? Do you help them with the determination of that decision or is that something that they come to you and they already know in advance they wish to have?

MR. PEACO: In this case they came to me with a specific objective in mind and asked -- you know -- looked at the proposals from us and some other firms and asked us to do the specified scope of work.

We of course would offer folks advice. We do work for utilities, we do work for commissions and consumer advocate organizations as well. So we can advise any of those organizations on what our experience has been as to what is practised in other jurisdictions in terms of regulatory oversight or review or so forth. But we weren't asked for an opinion on the proper way of forwarding this case.

MS. LEBLANC-BIRD: You were not asked for an opinion as to the proper --

MR. PEACO: As to what the proper scope would be, that is correct.

MS. LEBLANC-BIRD: Okay. Secondly, is there a standard or a governing body or a code that dictates the contents, tools of measurement or foundations of these different reports or audits?

MR. PEACO: For the -- for accounting purposes, if you were doing an accounting audit, there are any number of standard practices and documents for how to approach an accounting audit. I'm not an expert in that area. My expertise is in power contracts and modellings.

So our review -- part of the reason we have, you know, had some ambiguity about the term audit is this is not an accounting or a financial audit. This is an audit for technical review of the analysis done from the perspective of an outside power system planning individual as opposed to an audit from a financial or accounting perspective.

MS. LEBLANC-BIRD: Is there a governing body or is there an association that somebody doing an audit would join and belong to that would have a standard for these different types of audits? I'm just asking that question because it's not my field of endeavour of course.

MR. PEACO: Yes. Not for the kind of work that I do which is a technical review. As I say, I think it's standard within the accounting industry to have such standards, but this kind of review is somewhat different from that.

MS. LEBLANC-BIRD: Could a technical review differ from one organization to another? Another organization like La Capra doing the same sort of work, could a technical audit be something completely different done by another organization, or a prudency review or a reasonableness review? Is there a standard as to what that is?

MR. PEACO: No. I think the only standard is the specified scope of work in terms of what we were asked to look at and the timeframe we were asked to look at the material and come to -- and the conclusion we are asked to draw from the material.

MS. LEBLANC-BIRD: Okay. Ms. MacFarlane, I have just one quick question for you.

Yesterday morning you spoke of how the inputs to the PPAs were subject to challenge by Disco, and that the challenges were often resolved by consensus. And I just wondered if you could describe a situation where a challenge by Disco could occur and explain the procedure or outline the process from the raising of the challenge to its consensus resolution. And that would be the form the challenge would take, either written or oral, the parties task to resolve the matter and the reduction to writing or what agreement would be reached in relation to that, please?

MS. MACFARLANE: An example I can cite is the planned outage at Coleson in 2006/2007 for the second precipitator. The tolling agreement for Coleson Cove and the vesting agreement for Genco, in fact all three of the PPAs, indicate that best efforts will be made to contain the outages to the summer months. So that during the winter months -- in fact almost shoulder months, during the summer months they are available for export, during the winter months they are available to handle the heating load in New Brunswick, and the outages are scheduled around the spring and fall to the extent possible.

The outage for the precipitator at Coleson Cove I believe was an example where it would extend outside of the dates specified in the terms of the contract, so that was something that Genco had to bring to the Operating Committee. And Disco obviously challenged that and looked at the entire maintenance schedule, looked at other options and opportunities for finding a way to schedule that outage in a period when it would be less -- when it would fit within the terms of the contract. They would have looked at the cost of doing the outage in that off schedule season. And in looking at all those factors, they would have had to be convinced that there was no other option but to do it at that time.

The committee would have met on that issue more than once, brought to the table people who were guests I guess we referred to them the other day -- guests to the committee who could speak to some of the challenges of the project and the challenges of the timing of the project. Who could speak more broadly to some of the reliability concerns with the other units and why they had to be scheduled as they were. At the end of the day that issue would have been reduced to writing in the form of minutes of the Operating Committee.

MS. LEBLANC-BIRD: Thank you very much, and thank you, Mr. Peaco.

MR. BELL: Ms. MacFarlane, in your discussion with Mr. MacNutt you talked about change to the method to determine the incremental cost for the purpose of calculating the hydro adjustment, is that right?

MS. MACFARLANE: Yes.

MR. BELL: And this change was approved by the Operating Committee?

MS. MACFARLANE: That's correct.

MR. BELL: Does this mean the method was not prescribed by the PPA?

MS. MACFARLANE: That's correct.

MR. BELL: So who created the original method of calculation?

MS. MACFARLANE: The original methodology, which was to look at the top of the dispatch curve including exports, was a choice of methodology.

Calculating the hydro adjustments is new. It was a choice of methodology that not sufficient rigour was given to. It was determined without enough analysis and probably based on past practice with respect to choosing incremental cost levels for other purposes.

It was only as the credit started accumulating and became very material that the logic behind it was challenged.

And again this would have been a challenge brought to the Operating Committee.

And it was at that time that the analysis was done with much more rigour. And again the minutes of the Operating Committee would document that this discussion went on over a significant period of time.

And finally the analysis was presented in a method that was deemed to be consistent with the original setting of the vesting price and fair to both parties.

MR. BELL: So the methodology was worked out in the first place for October 2004? There was a methodology behind the calculations?

MS. MACFARLANE: There was a methodology. It was not -- subsequent to that being put in place it was determined that it was not -- the methodology chosen was not chosen with sufficient analysis.

MR. BELL: And I guess my comment is that -- and who deemed that it wasn't sufficient analysis?

MS. MACFARLANE: I think it would have been the Genco members of the Operating Committee when they would have seen the level of credit, of hydro adjustment credit as it was accumulating during the year.

And it was at that time that they began to question whether or not the methodology in determining it was appropriate, as they have the right to do.

And the Operating Committee brought that to the Operating Committee and challenged Disco. And it was through that Operating Committee process that a resolution was reached.

MR. BELL: So it was Genco that was opposed -- you know, in opposition to the change? Or excuse me, they were the ones supporting the change?

MS. MACFARLANE: They were the ones at the committee supporting the change. But with the analysis presented and with significant discussion it was determined that they were in fact correct and that the methodology that had been used from October 1st was leading to a double counting of the credit to Disco.

MR. BELL: So using the methodology from October 1st 2004 -- and I think you have made an undertaking to do a parallel using that methodology for the Board --

MS. MACFARLANE: Yes.

MR. BELL: -- that would be -- it would have been a benefit to Disco?

MS. MACFARLANE: That's correct.

MR. BELL: And a fairly substantial benefit?

MS. MACFARLANE: That's correct.

MR. BELL: Mr. Marois, were you involved in this at all?

MR. MAROIS: Yes, I was informed. And I followed the discussion.

MR. BELL: I beg your pardon?

MR. MAROIS: Yes. I was involved, not in all the discussions. But I was involved in the process.

MR. BELL: And what side did you take in this?

MR. MAROIS: The right side.

MR. BELL: Which is what?

MR. MAROIS: It's doing it the proper way. It's pretty obvious when you look at it, that the previous methodology was not appropriate.

Like Ms. MacFarlane said, really when you set the vesting price, the way the vesting price is set at the beginning of the year, it's set at normal water levels. And that vesting price is set using in-province load.

So it's only normal that when you adjust the price during the year to reflect actual hydro level, that the same approach is used, i.e. based on in-province load. So you are comparing apples with apples. In other words, the only thing you are changing is the actual hydro level.

With the previous methodology you were using in-province load to set the vesting price and total load including exports to set the hydro adjustment. So you are comparing apples with oranges. It didn't make any sense. So that for me was the convincing argument. I mean, it just -- it didn't make sense to do it the other way.

But the other thing too is, like Ms. MacFarlane mentioned, is Disco and its customers benefit from hydro adjustments in three ways. The main way is through the hydro adjustment the way I have just described it. The other way is indirectly through exports. And that's where the export load comes into effect.

And the third way is since the price for interruptible customers is set on an hourly basis, they will implicitly benefit or pay for any changes in hydro.

So these three things combined capture all variances caused by hydro. So for me it was pretty obvious that the revised methodology was the right one.

The philosophy was the same. Like the intent was to calculate the impact of hydro adjustment based on marginal prices -- or sorry, the changes in supply prices. It's the application of the methodology which was wrong.

MR. BELL: So you would -- would you have considered last year's hydro levels windfall for the company, for Disco?

MR. MAROIS: I'm not certain I understand your point.

MR. BELL: Well, with the higher levels of hydro production, the benefits of a -- we will call it a windfall -- wouldn't they -- wouldn't they or shouldn't they trickle through to the ratepayers?

MR. MAROIS: Well, it depends. If there was an actual mechanism approved by the Board ahead of time -- and that's what we are considering right now. I think Ms. MacFarlane has alluded to that.

From Disco's perspective, if Disco ever wants to have predictable returns, it's going to have to find a way to manage these risks. And these risks can go both ways. So that's why I hesitate calling it a windfall.

Last year, like we said, because of a series of events, low in-province load, high hydro, high costs in the U.S. because of Katrina, all of that together created a very favorable year.

The opposite could happen. And it has happened. Because that's one of the reasons why we have lost so much money in certain years. So right now what we have is consistent with past practices. Past practices before restructuring, these risks resided in Disco.

Now we are considering on a go-forward basis, and we will have to come back to this Board to get it approved, mechanisms to try to make our return more predictable. Otherwise we will never be able to go to the financial markets.

MR. BELL: So as Vice-president in charge of Disco you didn't put up any opposition? Or you didn't look at your customers in the sense of the benefit that it could be to your customers? You didn't -- you didn't oppose this at all?

MR. MAROIS: Well, like I said, if I would not have been satisfied that the change in methodology was the right thing to do, I would definitely have opposed it. But I'm not going to oppose something just because it's going to result in a higher cost to me. My criteria is common sense and is it the right thing to do.

MR. BELL: But aren't you responsible for your bottom line for Disco?

MR. MAROIS: Yes. And one way of getting there is applying the PPAs properly. And the change is the right way to apply the PPA.

MR. BELL: So the original methodology was not proper?

MR. MAROIS: It was wrong.

MR. BELL: It was wrong?

MR. MAROIS: Yes.

MR. BELL: And so the Operating Committee -- I guess what I'm getting at is who developed the original? There must have been some thought pattern behind the original calculations and methodology?

MR. MAROIS: Yes. And like everything in life, it's not perfect. So I'm certain that the people that developed the initial methodology had the best intentions.

But when you look at it with a fresh set of eyes or with experience, you realize that it really wasn't doing the right thing.

MR. BELL: So it is going to be an ongoing process where the Operating Committees can change the PPAs and the structure of the methodology calculations?

MR. MAROIS: Well, this was not a change to the PPA. I mean, what the PPA says is you would calculate an adjustment for hydro. It's the way you did the calculation.

And I mean, we are still in transition here. This is the first year we have the application. We are going to find some of these things that can be improved.

But I mean, what I'm hopeful is after one or a couple of tries that it will have resolved many if not most of these things. And that's why we have got experienced people working on the Operating Committee. We also have

-- I don't know if you got that yesterday when Mr. Kennedy was mentioning it.

But we have two full-time people assigned just to manage the PPAs. So these people -- really as we go, some of these details come up, they are addressed, they are resolved. So on a go-forward basis I'm confident it's going to be more -- managing the PPAs will be more mechanical.

MR. BELL: I would like --

MS. MACFARLANE: Excuse me. Just before we finish that, if I could just add -- you mentioned, you asked the question shouldn't the windfall from additional hydro accrue to the ratepayer.

The ratepayer pays -- included in rates is average hydro. Every year we budget on and include in our revenue requirement average hydro. These pluses and minuses that over time will presumably equal out accrue to the shareholder.

If there is a -- and it's the shareholder who takes the risk of poor hydro in certain years. It's the shareholder who then takes the offset of high hydro in other years. The ratepayer always pays on the long-term average.

MR. BELL: Thank you. ENG -- Enbridge IR number 17 in

A-80. And I guess what I'm looking at under the capacity and the capacity payments -- 17, A-80 --

CHAIRMAN: Go ahead.

MR. BELL: Under Bayside, Bayside is a must run for five months of the year, the other seven months it's on standby?

MR. KENNEDY: The other seven months it's in the market it operates as a merchant plant with respect to Bayside Power.

MR. BELL: But we are still paying the capacity payments for those seven months that it's in the market?

MR. KENNEDY: Our capacity payment is based on a nominal capacity payment of 2425, and that takes into the account the fact that the Bayside Power is in the merchant market for those seven months of the year.

MR. BELL: But we are still paying that capacity payment to Bayside even though it's not on the system?

MR. KENNEDY: The capacity payment to Bayside is factored in as a dollar per megawatt hour basis. So they are not consuming energy -- they are not providing energy to us, so therefore we are not paying the capacity payment. The capacity with respect to the fixed costs with respect to that contract as well as the energy cost is based on the dollars per megawatt hour basis. Therefore, since we are not taking any power the seven months of the year we are not paying those costs.

MR. BELL: So I guess maybe I'm looking at this chart in a little different light then, because from what I look at is the fact is that for seven months of the year we are still paying the capacity payment.

MR. MAROIS: What are you looking at, please?

MR. BELL: Enbridge IR-17, A-80 -- Exhibit A-80.

MR. KENNEDY: What you are referring to I believe is the item that's beside Bayside Power with respect to purchase power, is it?

MR. BELL: Yes.

MR. KENNEDY: That basically is a nominal capacity based on name plate. It doesn't specifically deal with individual units. It's a nominated capacity that describes the capacity -- the name plate capacity of these units.

MR. BELL: I guess maybe I will clarify this. In the 2425 megawatts that is nominated capacity, Bayside is part of that, am I correct?

MR. KENNEDY: Yes.

MR. BELL: And therefore I guess what I am saying to you, Disco is paying to Genco for those 2425 megawatts all year?

MR. MAROIS: But I guess the point here is I'm not too sure -- I'm not that familiar with that spreadsheet. I don't know what it's breaking out. I guess it's consistent with the PPA. But what is important I think is based on the PPA, Disco has contracted 2425 megawatts of capacity and we have access to that capacity year round no matter where it comes from.

So here it's broken out between facilities but in reality it might not come from Bayside but it might come from somebody else, but Disco pays for 2425 megawatts and gets access to 2425 megawatts on a 12 month basis. So this is kind of illustrative of where it could come from but it doesn't necessarily come from those specific sources.

MR. BELL: So in other words, if in those seven months that Bayside went out on the open market, would they then give the credit to Genco or Disco?

MR. KENNEDY: If I could refer you to exhibit A-12 --

CHAIRMAN: You have got us on that one. That's back in the office.

MR. MORRISON: I believe that's from the CARD portion.

CHAIRMAN: Yes. That's from the CARD. I'm going to suggest that you wait to answer that question until after the break, rather than us waiting on you as it were here now.

MR. KENNEDY: Okay.

MS. FERGUSON SONIER: Thank you, Mr. Chairman. Ms. MacFarlane or Mr. Marois, in the evidence I could not find the organization chart of the utility. Could you provide it to us after the split of NB Power.

MS. MACFARLANE: Yes.

MS. FERGUSON SONIER: Thank you.

MS. MACFARLANE: Are you looking specifically for Disco or are you looking --

MS. FERGUSON SONIER: Not necessarily, no. The whole utility.

MS. MACFARLANE: Okay.

MR. DUMONT: Ms. MacFarlane, yesterday you mentioned the -- there was a settlement for the precipitator at Coleson Cove between you -- Disco and the designer or contractor of the precipitator. What was the amount of the settlement?

MR. MORRISON: You are looking for the settlement, Commissioner Dumont?

MR. DUMONT: Settlement amount, yes.

MR. MORRISON: I believe, and I will have to double-check that, we had some discussion about that yesterday -- I think that settlement amount was done on a confidential without prejudice basis, but can you -- can we wait? I will try to get some instruction from in-house counsel on that and answer that on the break. It's not a question of not wanting to provide the information, just a question whether there is any ramifications to doing that.

MR. DUMONT: Yes. And could you provide with that when the settlement occurred and when payment was made?

MR. MORRISON: Yes. I will get that information.

MR. DUMONT: Thank you.

CHAIRMAN: I was going to ask that question too because after the absolutely amazingly simple answer that Ms. MacFarlane gave, that question just flew out of my mind. Thank you for asking it.

Just a couple of questions. Mr. Lawson was questioning you in reference to the export credit and to my surprise you indicated that you did a run of PROMOD on October 1 of each year to see what it would predict you would sell on the export market in the following fiscal period. And then adjustments were made on the credit at that time and then I guess monthly throughout the year after that.

Now my understanding is that the credit is established over five years. In other words, it's a five year prediction. My question is rather simple, because most of the predictions and runs, et cetera, are done on an annual basis with PROMOD, why on earth do you set the predicted export sales for out over a five year period, why wouldn't you set it on the 1st of October when you have got that run period?

MS. MACFARLANE: The answer is a little bit of we do both. The PPA specifies a five year forecast and I believe again that was from the financial advisors thinking that that would bring some degree of predictability or certainty to the setting of the vesting price.

So there is a number, four or five years, in the vesting contract.

Every year the number is recalculated based on what the current market prices, both for fuel and for export prices, will lead to. And then whatever comes out of the PROMOD run done annually for the October 1 date is compared to what is in the contract and that sharing formula is applied. And if there is any sharing to or cost to Disco it is added to or subtracted from the amount that is specified in the contract.

CHAIRMAN: Okay. Thank you. Now I think this has been answered, but since the opening of the market there have been no changes to the PPAs?

MS. MACFARLANE: That's correct.

CHAIRMAN: And so therefore the PPAs which the Board has on file, those are up to date and current?

MS. MACFARLANE: That's correct.

CHAIRMAN: Good. Thanks. Mr. Peaco, would you consider yourself to be familiar with the North American electricity markets?

MR. PEACO: Yes.

CHAIRMAN: Very simple question. On the basis of that knowledge, are you aware of any other jurisdiction that its public policy has been to go to a competitive market place for generation -- excuse me -- let's phrase it -- a competitive market place for wholesale, large retail or even retail as well, where when setting up that market place PPAs were used as they have been in New Brunswick?

MR. PEACO: The analogy that -- in the US that is -- most closely resembles this would be many of the States that set up restructuring in the United States set up transitionary periods. Some of them were actually literally sale contracts back, some of them were implicitly contracts.

One example I can think of is in Pennsylvania. They didn't explicitly have the contract per se with the utility but they unbundled but didn't divest generation, but the generation company was obligated to back stop the standard offer for a period of years. So it had some of the same effect.

The -- in the case of for example the New England electric system in Massachusettes, when they divested their assets, the divestiture included a sell back contract to cover the seven year standard offer period from the owner of the assets. And so that contract effectively back stopped the standard offer that was offered up until -- I think it ended just recently in '05 in Massachusettes.

So the concept of a vesting contract, if you will, as a transitionary mechanism to go from a vertically integrated bundled structure to a competitive market has many parallels in some fashion or another in the way the transitions were structured. This contract clearly is longer term than many of those, but conceptually that analogy would exist in many of the States that went to restructuring.

CHAIRMAN: Just following up on what you just said, are you aware of any place that the back stop period for the standard offer is as long as it is here?

MR. PEACO: I'm not sure if I'm clear as to what the back stop period is here.

CHAIRMAN: I think it's as long as the heritage assets last, is my reading of it.

MR. PEACO: Yes. The only question I have is that obviously the contract provides for reduced nominations over time and it wasn't clear to me whether there were some other policy as to how that would occur. But so long as it's purely at the company's election as to when to step down on those, that would affect that, but if -- if you are looking at it in terms of the life of these contracts, clearly the transitionary period usually in the United States were somewhere between four and ten years, depending upon the jurisdiction.

CHAIRMAN: Okay. When in the other North American jurisdictions were PPAs common -- PPAs like these commonly used?

MR. PEACO: There was any number of ways to resolve sort of the unbundling of the vertically integrated utilities. I don't know if there is any exact analogies to these particular PPAs but clearly -- in the example of Pennyslvania, clearly there was explicit -- you know -- in effect the PPA between the generating company and the retail company to provide the standard offer service, that was administered more through regulatory order I believe. I'm not familiar with the exact form of that, but that would have the same kind of an effect. So I'm not sure which -- what distinction you are trying to draw between an example like that and these PPAs.

CHAIRMAN: Well in the market that you have just described, that is, in that period, why those PPAs would be under the watchful eye of the regulator, would they not?

MR. PEACO: No, not necessarily. There was a deal -- in that example effectively when the restructuring was done there was a deal strike and legislation or commission ordered, depending on the jurisdiction. But take the Pennyslvania example, there was an understanding that there was a fixed price to be delivered for standard offer service and that was the terms and conditions. The asset -- generating assets were in the unregulated generating company and there was no -- from that point forward there was no cost of service regulation of the generation. It was simply the terms and conditions of the standard offer that the generating company must have had to meet.

CHAIRMAN: Okay. Good. Thank you.

MR. MAROIS: Mr. Chair, without knowing all the details, I think the Quebec situation has a lot of similarities to what we have done here in terms of restructuring.

CHAIRMAN: Yes. In some cases it's even more restrictive, as I understand it. That is, the regulator is more restricted, but then again it's a Crown corp. as well. Okay. Thank you very much. We are going to take our break now so that you can have an opportunity to look at those things.

(Recess)

CHAIRMAN: Do we have an answer to the question that Commissioner Nelson put?

MR. MAROIS: I will do my best.

CHAIRMAN: Now there is at least 12 to 15 degrees up here. Surely you can explain it to us.

MR. MAROIS: Well, first I would like to say it's a good question. And I will try to address it in two steps. The first thing is Disco pays Genco a capacity charge related to the capacity that Genco makes available to Disco no matter the source. So that's the first thing I would like to say.

And the way that capacity charge is determined naturally is with a numerator divided by the denominator. The numerator is just Genco's fixed cost excluding any cost from third party NUGs.

So really the purpose of the capacity charge paid to Genco is to recover Genco's own fixed costs, not any fixed costs of the NUGs. So you take those costs and divide them by the capacity that Genco makes available to Disco, which is the 2425 megawatts. And that gives you a capacity charge.

The 2425 -- you could use anything else. You could use 2000 and have a lower charge per unit. Or you could use 1000 and have a higher charge per unit. So the denominator, the role of the denominator, the 2425, is really there to set the charge.

But what's important in my first point is the capacity charge paid by Disco to Genco is only to recover Genco's fixed cost.

So my second point is the charges related to Bayside are entirely energy-based, entirely variable. So you only pay for Bayside in the months they are generating. So conclusion is that we are not paying for capacity related to Bayside when Bayside is not available.

So I don't know if that answers the question, but --

CHAIRMAN: Sorry. I will just try and get my head around this. In other words, what you are saying is the exhibit is wrong?

MR. MAROIS: No. The exhibit is not wrong. And the exhibit is consistent with how the PPA was set. And again I'm not that familiar with this exhibit, but --

CHAIRMAN: Well, Mr. Marois, who is?

MR. MAROIS: No, but --

CHAIRMAN: Because I'm looking at it. And it says "capacity". And it lists them down. And Bayside Power shows a capacity payment right across all 12 months. I'm sorry, Commissioner Nelson. That is yours, but --

MR. MAROIS: It's not a capacity payment. Really, if you go back to my explanation, what I explain is to determine the capacity charge paid to Genco, the two variables were Genco's cost divided by capacity.

What this sheet really does, and it's consistent with the PPA, it just says which capacity number should we use? And we used 2425. And this explains how the 2425 came up. Like I said, it's almost irrelevant. Because at the end of the day you could use any number, which would give a different capacity charge. And as long as you multiply the capacity charge by the capacity, the objective at the end of the day is to recover Genco's fixed costs.

So the way this is presented and the way the PPA is presented, I would potentially say it's not as clear as it could be. But it doesn't impact the amount that Disco pays to Genco.

MR. NELSON: Mr. Marois, I'm looking at the end number on here. And it is 266 million 761. And I look at A-96 that you -- one of your exhibits. And it is 266,800,000.

MR. MAROIS: Let me just --

MR. BELL: A-96, your exhibit.

MR. MAROIS: So what does A-96 say, you say?

MR. NELSON: It is 266,800,000. And here it is 266' on the exhibit -- or on the IR from Enbridge it is 266 million 761. S that's pretty close.

MR. MAROIS: Yes. I'm not disputing the 267,000,000. What I'm saying is the purpose of the 267,000,000 is to pay Genco for its own fixed cost. It's just a pricing mechanism.

MR. BELL: I guess the question I have then is, so what you are saying is that during those seven months that Bayside is not required, we will call it, it is not in the base load, they do not get any money?

MR. MAROIS: Exactly.

MR. BELL: So during that period of time they get nothing from Genco or Disco or anybody?

MR. MAROIS: Exactly.

MR. BELL: So therefore they are only paid for the five months that they are required?

MR. MAROIS: Yes.

MR. BELL: So there is no money flow through during those seven months period?

MR. MAROIS: Exactly. I don't know if it's yes or no, but exactly.

MR. BELL: So why would this be --

MR. MAROIS: What would this be?

MR. BELL: In this chart here it looks like they are being paid for that period of time. Because if you look at it, in the five months there is no variance in the five months versus the seven months?

MR. MAROIS: Yes. But like I -- that's where it gets confusing. But the $267 million -- is it 267 --

MR. BELL: 200' --

MR. MAROIS: -- or $266.8 million --

MR. BELL: Yes.

MR. MAROIS: -- that's paid to Genco to allow Genco to recover its fixed costs for its own facilities. None of that money goes to the NUGs. So that's where it gets confusing.

The only purpose of showing all these facilities at the top of the response to the IR is just to show how the 2425 megawatts was derived.

And the 2425, the relevance of that number is really Genco has 266,000,000 to recover. You divide that by the 2425. And that gives you a capacity charge payment that's in the contract.

So the 2425 is just kind of a volume set in the contract for billing purposes. But it doesn't mean that any of that money flows to a third party NUG.

You could say the same thing for any of these plants.

Many of these plants won't be at the level that's built into 2425. The 2425 is purely a billing determinant.

DR. SOLLOWS: I wonder, to help me understand this matter, could I ask you take out the -- I think it is A-4 that contains the vesting PPA. And I'm referring to schedule 1.1.67 which is a schedule listing the Genco heritage assets.

Schedule 1.1.67. Schedule page I, it is a schedule to the vesting agreement, the last agreement in the binder that I have.

I will wait for them to find it. Do you have that?

MR. MAROIS: Yes, I do.

DR. SOLLOWS: Okay. When I look at the table that is presented I have -- I see that it lists the facilities that are included in the Genco heritage assets. And I see the first column identifies the unit.

The second column identifies the demonstrated net capacity I think of the unit in megawatts. And the next two columns allocate that demonstrated net capacity between base load assets and peaking assets. And the final column has the shutdown date.

Now when I follow those columns down and onto the other side of the piece of paper, it carries on again splitting each demonstrated net capability into base load and peaking.

And at the end of the column I see -- at the very end of the table I see the Heritage assets as of January 1st 2005 being 2445.1 which I think has been revised to be 2425.1. I see -- I have got a note here saying that.

But whether it is 2425 or 2445 is really immaterial to the point. It seems to me that this denominator that you are talking about is this base load asset.

MR. MAROIS: Yes, it is.

DR. SOLLOWS: And when I take the base load assets and the peaking assets, which are to be -- come along with the nominations for whatever base load you have, they add up to the total assets.

So I don't see how you can come up with 245 megawatts or 250 megawatts out of any other assets. You don't have any more assets. Can you explain how you get that?

MR. MAROIS: Well, I didn't understand your conclusion. What do you mean, come up with additional 245?

DR. SOLLOWS: Well, when I add 2445.1, that is the total amount of base load assets designated under the vesting agreement?

MR. MAROIS: Yes.

DR. SOLLOWS: All of your other assets are peaking assets and therefore not base load assets under the vesting agreement which is what you are telling us the base load --

MR. MAROIS: I don't understand the relevancy of your point here.

DR. SOLLOWS: Well, the relevancy is back in this capacity table you seem to suggest that well, it is broken out by various plants arbitrarily.

And it could be satisfied that Bayside Power capacity of 263 megawatts could be satisfied by capacity from some other plants. But obviously it can't be because there is no other capacity on the system to satisfy it.

MR. MAROIS: Okay. Let me try to bring back -- redo my explanation using these sheets. If you take the capacity that's derived from the sheet we have just looked at in the PPA, the 2425 which is the 2445 adjusted for the -- based on the note below -- then if you go a couple of pages before that, which is the beginning of schedule 1.1.17 -- and if you go to the second page which is page ii. And you have got a schedule of monthly payments. And those are the capacity payments.

So my understanding of the way the PPA is made is you take these capacity payments, multiply them by the capacity that is made available to Disco, which is the 2425, and that gives your 266,000,000.

And the purpose of the 266,000,000 is to compensate Genco for its own fixed cost excluding the fixed cost of the NUGs. So that is what is important here is the size --

DR. SOLLOWS: Just to clarify that, where is that purpose outlined in the evidence or in the contract?

MR. MAROIS: That's what I'm explaining.

DR. SOLLOWS: But I thought these were given to us by the advisers to the Province.

MR. MAROIS: That's what I said.

DR. SOLLOWS: Were you one of the --

MR. MAROIS: That's my understanding. Because --

DR. SOLLOWS: So your understanding is that is the purpose. But you don't know that to be the case?

MR. MAROIS: I don't know the details. But that's the question is posed to me.

DR. SOLLOWS: Yes.

MR. MAROIS: And what I'm saying is these charges are made -- my understanding of these charges is to allow Disco to recover its own fixed cost.

So then any costs that are paid to the NUG's, Bayside in particular, are paid on an energy charge basis. So that's why they only get paid if they run.

MS. MACFARLANE: Perhaps I can help.

MR. MAROIS: Different approach.

MS. MACFARLANE: Different approach, that's right. The PPAs were constructed in order to have Disco, which has both the rights and the obligations to the Heritage assets, pay Genco for the fixed costs related to them.

The fixed costs were obviously determined in the model. And then somehow that had to be turned into a rate. One could have just set a total monthly payment.

But this contract has to last for 25 years and has to allow for the nominated capacity to decrease as customers leave. So it had to be turned into a rate that was able to be applied to something.

When Genco's fixed costs which is the numerator in the equation for the rate was determined, schedule 1.1.67 outlines all of the heritage assets. The numerator would have included the costs, the fixed costs of the base load assets owned by Genco and the peaking assets owned by Genco.

So you will notice on the second page of this schedule hydro in total has 888 megawatts of capacity available. It's broken out in this table between base load and peaking because of the operating characteristics of the unit.

But there are fixed costs related to all of them.

There are fixed costs related to Millbank, to St. Rose, to Grand Manan, to Courtenay Bay.

The total of the fixed costs for just the assets owned by Genco, not the heritage PPAs, not the NUGs, is the numerator. The denominator had to be something. And the financial advisers chose the denominator to be base load assets.

They could have chosen something different. They could have chosen to take -- and perhaps it would have been more transparent if they had taken the total fixed costs for all Genco's assets and divided by the DNC for Genco's assets.

And the rate would have been different. But then that rate times the total of the base load assets and the peaking assets would have led to the same number. The same fixed costs have to be recovered. Are you following me?

DR. SOLLOWS: Oh, I'm following you, yes.

MS. MACFARLANE: So it is simply, as Mr. Marois has said, the billing determinant that the designers of these PPAs chose. They could have chosen something different.

But at the end of the day you come up with a rate that ends up being multiplied by a billing determinant that collects Genco's fixed costs from Disco and ultimately from Disco's customers. It's just the design of the formula --

DR. SOLLOWS: I guess -- so the fact of the matter is and you are arguing is that an unintended consequence of them choosing the base load capacity under the heritage agreement was that it made it inconsistent with the contracts that Genco had signed with respect to the Heritage PPAs, is that right?

MS. MACFARLANE: It makes that particular exhibit very convoluted is all it does. As I say, they could have taken the total fixed costs, let's say 267,000,000 that had to be collected. They could have divided it by the total of the DNC of the assets Genco owned. The rate per month would have been different. But then the rate per month would have been multiplied by the total of the peaking and base load assets owned by Genco. And you would have still ended up with 267,000,000.

DR. SOLLOWS: Is it possible that the authors of the PPAs perhaps judged that you really had excess assets and they constructed this formula in this particular way and expected it to be applied as Vice-chairman Nelson suggests as a way of incenting Genco to be more efficient and more careful in its construction program?

MS. MACFARLANE: I'm not quite following the logic that would lead them to be more careful in their construction program. Because no new assets will get added to the heritage asset pool. New construction will not be part of the heritage asset pool.

DR. SOLLOWS: I guess what I'm getting at, is it possible that the framers of the PPAs, which I understand was not Genco or the new NB Power group of companies, is it possible that they took the view that the estimates that they were given for the magnitude of the fixed costs were too high in their view, and they were constructing a formula that would force you to deal with a more stringent financial situation?

MS. MACFARLANE: I don't think so. I think they simply were looking for something that, believe it or not, would lead to ease of understanding.

DR. SOLLOWS: Hindsight is 20/20, isn't it?

MS. MACFARLANE: That's right. So all they were attempting to do was ensure recovery of the fixed costs of these heritage assets.

And the PPAs allow for that to happen by assuming that all of the heritage assets have been nominated through the capacity payment.

Once the heritage assets -- or pardon me, once the nomination is reduced, obviously all of those fixed costs are no longer going to be recovered through that mechanism. And that's where the exit fee comes into play.

DR. SOLLOWS: Thank you.

MR. NELSON: Mr. Kennedy, getting back, staying on the same vein. During those seven months that Bayside is we will call it off-line, over the last -- I guess last year we will say the period from, when is it, April until October, was there any time that Bayside was brought on line or did you buy power from Bayside when other we will say utility generation was available at a cheaper price?

MR. KENNEDY: I'm not aware of any. That's during what period?

MR. NELSON: Say from April until say October when it's -- what is seven months that they are not on line?

MR. KENNEDY: It's the non-winter months, it's April -- starting in April.

MR. NELSON: Yes. Until the 1st of November?

MR. KENNEDY: Yes.

MR. NELSON: Was there any time during that period that there was generation available with your own generators but you chose to buy from Bayside?

MR. KENNEDY: No, I don't -- subject to check, but there was -- unless units were unavailable for some kind of outage or a severe problem, and I don't recall any of that.

MR. NELSON: Could you check?

MR. KENNEDY: Yes, I will.

MR. NELSON: Ms. MacFarlane, earlier -- I'm getting back to the exhibit 6 in Appendix -- what is it -- 80, about the hydro. And you mentioned -- talked about shareholders. When I mentioned ratepayers you talked about shareholders. Aren't the shareholders of Disco and Genco one in the same?

MS. MACFARLANE: That's correct, ultimately.

MR. NELSON: Because the way you -- I read what you said was Genco was different from Disco.

MS. MACFARLANE: Genco has different risks from -- Genco has different risks and therefore different risks and opportunities available to the shareholder. They do have the same shareholder.

MR. NELSON: They do have the same shareholder?

MS. MACFARLANE: Yes.

MR. NELSON: So wouldn't it have been a better benefit to not only the shareholder but the ratepayers was to carry on with the methodology that was used on October 1st, 2004, to figure out the hydro adjustment?

MS. MACFARLANE: Because it's a common shareholder I suppose you could say that in the end the shareholder takes the same risk or takes the same benefit. But the purpose of restructuring is for these companies to be viewed financially as stand alone and to understand how each company's costs are lined up with its revenues, and ultimately to get those companies out to debt capital markets to borrow in their own name.

So if there is inappropriate cross-subsidizations between the companies because of improper allocation of costs or benefits, that doesn't serve the purpose that the Province outlined for restructuring.

MR. NELSON: Thank you.

MR. DUMONT: Ms. MacFarlane, I am going back to an undertaking that I asked about union and non-union increases and merit increases. In that response you didn't answer -- what I wanted to know is what is a merit increase?

MS. MACFARLANE: Generally speaking, when a position is created there is a range set for the position such that as the person enters it at a junior level and then moves through training and experience to a fully competent level, they go up the scale.

So the position let's say would be paid between 45,000 and 55,000, and an entry level person who meets the minimum qualifications would come in at 45,000, and then each year they would receive a merit increase on the assumption that they have received the training and experience that is moving them towards full competence. Once they get to the top of the scale they receive no more merit increases.

MR. DUMONT: Okay. So from what I hear is that it doesn't matter how you perform or not it's the amount of time you are there and the training you have received.

MS. MACFARLANE: There are annual performance reviews done before the merit increase is awarded, and if the person is deemed not to have moved to improved in their competence, then the supervisor can deny the merit increase.

MR. DUMONT: Okay. So how do you schedule and plan a merit increase?

MS. MACFARLANE: They are done on the anniversary date of the employee's hire. So each employee, human resources would notify the supervisor that a merit review is required and that a merit increase is due pending the outcome of the review, and the supervisor undertakes that work and makes a recommendation to human resources. And then they apply the merit increase or not, depending upon the circumstances.

MR. DUMONT: So that person's immediate supervisor would decide if he gets the merit increase or not?

MS. MACFARLANE: That's correct.

MR. DUMONT: Okay. And have the management -- the management bonus payments that were cancelled last spring because of a predicted short-fall, were they reinstated for the coming year?

MS. MACFARLANE: For 06/07, is that what you are asking?

MR. DUMONT: Yes.

MS. MACFARLANE: -- or for 05/06? A decision has not been made on that yet.

MR. DUMONT: Okay. Thank you.

DR. SOLLOWS: Thank you, Mr. Chair. Now I guess I will be going to my prepared questions. Mr. Marois, when we were discussing this last week I think, in reference to the first cost allocation study that you filed in this hearing, and the reference in the transcript where we were discussing this was the 13th on page 3863 -- I don't think you need to look it up unless you think I'm misquoting you -- you said "The only significant change we made to our cost allocation study was as a result of restructuring, and that was what we filed to this Board. We believed at the time and we still believe now that what is driving the costs for Disco are the power purchase agreements and that is why we allocated costs accordingly. Prior to restructuring, the cost allocation studies we had done, subject to minor refinements, were based on the previously approved Board methodology." Is that -- I think I have done that fairly.

MR. MAROIS: Yes, that sounds reasonable.

DR. SOLLOWS: Now when I heard that, I took it to mean that the cost allocation studies prior to restructuring were all done using the Board approved method. And to me it would follow that these cost allocation studies must have shown that industrial rates were set well below the cost of service, just as the study that you filed in January has shown.

But when we look at the NB Power Board policy manual -- I think that's in A-57, Appendix 7 -- that's A-57, Appendix 7, on page 49 -- we find the following item number 1, "number 1, establish a rate structure that is cost related and eliminates cross-subsidization of residential customers by achieving a residential cost recovery of 100 percent by 2010."

When I read that I'm left wondering why NB Power's Board didn't seem concerned with cross-subsidization of industrial customers. So my first question is, did NB Power's Board have access to and consider any of the cost allocation studies based on the Board approved methodology prior to approving this policy?

MR. MAROIS: This -- or the information that this policy was based on was the rate proposal we had in front of the Board at the time which was showing no cross-subsidization of industry.

DR. SOLLOWS: And so the answer is that they did not -- and they were not provided with this history that you had been keeping track of right up until this last rate proposal where you changed things and got a different result? That's the only one that Board saw?

MR. MAROIS: Well the Board didn't actually even see -- this was prospective looking and when this was done -- and this was going to be work in progress. I mean actually this will evolve depending on the context, but at that time the information we had was there was no cross-subsidization of industry. So it was not an issue to be addressed by the Board.

DR. SOLLOWS: But you told me that they -- that you had prepared these every other cost allocation study up to that point and prior to restructuring had been prepared, according to the Board approved method. And the Board approved method is what you delivered in January showing a major subsidy to industrial customers. And I'm wondering why the Board wasn't informed of that before they made this policy?

MR. MAROIS: The only thing I can say is we probably were confident that what we were proposing would have been approved by this Board.

DR. SOLLOWS: Also on that page we find item 2, and item 2 says that the policy is to propose a rate structure that sends the appropriate price signals to customers by eliminating the declining block rate and replacing it with a flat rate by 2007, and increasing the block rate -- and increasing the block rate by 2010. My question is is this specific to residential customers or does it apply to all customers?

MR. MAROIS: This was specific to residential customers.

DR. SOLLOWS: And I think you have probably already answered my second question, was what informed the policy choice, I guess it was the first cost allocation study that you filed in July. Is there anything else?

MR. MAROIS: It was the information that was available at that time.

DR. SOLLOWS: I guess is the information that informed that policy choice available on the record in this hearing?

MR. MAROIS: Well the base was what we had filed with this Board, yes.

DR. SOLLOWS: So all the information that your Board had when it settled on that policy we too have?

MR. MAROIS: Yes.

DR. SOLLOWS: Okay. Thank you.

MR. MAROIS: And I guess I just want to stress again that even though I think the way -- first of all these were the first ENDS policies approved by the Board, so that's why I mentioned it's work in progress and they are going to evolve. And the general statement will probably not evolve as much but the accordinglys or the details as we get more information, as decisions are rendered by the PUB, all that, these will be adjusted on an ongoing basis.

DR. SOLLOWS: Okay. I now move to page 51 of the same policy manual, and under the heading "Environmentally sustainable energy" we find item 2, and item 2 says, "2, the NB Power group of companies will support the Province's demand side management initiatives."
Now I have taken the impression from your comments earlier in the hearing, Mr. Marois, that Disco has planned to do nothing in this regard except adjust it's rates to eliminate cross-subsidy. And so my first question is, what are the other members of the NB Power group of companies doing in this regard?

MR. MAROIS: Well I don't necessarily agree with how you -- your summary of what we said.

DR. SOLLOWS: Okay. If you could --

MR. MAROIS: What I said I think hopefully was that right now it's difficult for us to know where we fit with the new energy efficiency agency because we don't really know their platform, we don't know their initiatives. Once we know better where they are going it's going to allow us to determine our role. And so we don't want to create duplication, we don't want to overlap, but definitely we see we have a role to play. I mean we have the interface with the customer, we have the information. So we see ourselves playing an active role with the new agency but at this stage it's premature because I don't think they know their own role.

DR. SOLLOWS: Okay. That's Disco. My question was the other members of the NB Power Group of companies? The policy says the NB Power group of companies will support the Province's demand side management initiatives. So what about the other companies? What are they doing to support it, or are they doing anything?

MR. MAROIS: It's my knowledge or my understanding it's primarily Disco.

DR. SOLLOWS: So Genco is doing nothing to support it?

MR. MAROIS: No, not to my knowledge.

DR. SOLLOWS: Would Transco be bringing forward a proposal for a system uplift charge on the transmission tariff to fund the DSM initiatives as many other jurisdictions have?

MR. MAROIS: I'm not aware.

DR. SOLLOWS: Okay. Thank you. Now I want to refer to undertaking that has been marked as A-105. It was delivered on the 16th I think of this month. A-105. And it's a -- the question was to provide information on the fraction of assets that are managed, taking into account a reasonable cost of capital, and what fraction of assets are not so managed.

MS. MACFARLANE: Could I have the date of the undertaking again?

DR. SOLLOWS: The date -- the transcript reference -- it's undertaking number 11. It's dated February 13th, 2006 --

MS. MACFARLANE: Thank you.

DR. SOLLOWS: -- and it's exhibit A-105.

MS. MACFARLANE: Yes, I have it.

DR. SOLLOWS: Okay. Now as I read the response it shows that the test years capital budget includes $10.7 million for what is termed asset reliability investments, $27.8 million for what are termed load growth investments and $4,000,000 for process improvement and asset optimization. Further on it says that the issue -- the group asset reliability is said to relate to work on substations, vehicles, tools and equipment, and load growth relates to "requested work and planned improvements to the distribution infrastructure such as line extensions, water heaters, new services, service upgrades, et cetera." The response also states that the majority of capital work is non-discretionary in that it is driven by customer demand, load growth, safety and reliability measures. And finally it says that 90 percent of the capital additions do not include analysis requiring cost of capital assumptions as they are non-discretionary infrastructure/equipment.

So my question is, just to make sure it's clear, are we correct to infer from the response in A-105 that asset reliability and load growth expenditures are not subject to economic or financial analysis incorporating the cost of capital?

MS. MACFARLANE: They are not right now, Mr. Sollows. That process has to change. Our own Board is not satisfied with the degree of rigor in our capital investment decisions. This methodology is a carry-forward from pre-restructuring. Many processes have had to change. This is one that has not yet been changed.

And as I say, our own Board is dissatisfied with it and has asked that before we take forward the 07/08 budget to the Board that we change this process to include the the type of analysis you are speaking of on all investments.

DR. SOLLOWS: So on that basis I can assume that all of the little tags that I have marked in this book about transformers, sub-transmission lines, distribution stations, primary feeders, secondary systems, distribution feeders, capacitors, all of which relate to including the cost of capital in the planning and capital works budgets, you are going to deal with that before we see you again?

MS. MACFARLANE: Yes.

DR. SOLLOWS: So that saved us a lot of time. Thank you. The only other question -- well two questions relating to this just so that the record is complete. The thing that sort of jumped out at me in that list was load growth included water heaters. I mean it seems somewhat anomalous to me that that's in with the rest of infrastructure for the distribution utility. But I will just leave it at that and let you deal with it.

But the other issue is the topic of reliability. Can I also ask you to in your work to begin to specifically address the economic value of reliability? Again there is a section that I can cite from the Bible indicating that you really do have to take economics into account when planning reliability based investments, and there are accepted methods for doing it. So would you undertake to make sure that's dealt with in the proposal you take forward.

MS. MACFARLANE: Yes. And I would appreciate having the source book that you --

DR. SOLLOWS: No problem. I'm sure you -- you can have that.

CHAIRMAN: I might state for the record that's an engineer's Bible, not for the rest of us.

DR. SOLLOWS: So we are done with that line of questioning.

MR. MACNUTT: I just wonder for the purpose of the record if the title of that book could be put on the record at this time.

DR. SOLLOWS: We can if you wish, but it's just one of many such texts. The title is "Electric Power Distribution System Engineering" and it's by Turan Gonen, and it was published in the early '80s and I'm sure there may be more recent editions. There certainly are other handbooks available. They will all say pretty much the same thing. So I have no doubt that they will be able to find suitable references.

Now my next question deals with the thorny issue of the heritage PPAs. Now that really has left me somewhat confused. And I'm going to take you through how I ended up in this state.

Mr. Marois, you said to me on the 15th of February in the transcript at page 4076 -- and I have got it here. I will read it. I think I just cut and pasted into this. So it should be right.

"I guess, Mr. Sollows, we might be getting into the next panel", that being this panel. "But when you talk about designate natural gas generators as must run third party or NUGs, nonutility generators are quite different than utility generators. Because as you know, the utility generators the fixed costs gets recovered through different means. And it's only the fuel costs that end up being dispatched. While we have a NUG, I mean, the price we pay to a NUG includes both fuel and their operating costs. So that will impact how you dispatch these third party contracts. So they have to recover their cost. And we will see more and more of that as we go. The more we go to third party generators, these will have to be considered must run. Because that is the only way these projects will get financed. So it's a reality. The way you portray it, referring to me, seems -- almost seems like it's discretionary. It's a fact of life that when you have a third party generator you must pay them. If they run you must pay them. Otherwise they will never get financing."

And that is the extent of my quote. When I listen to that and when I reviewed it it left me with a very clear impression that the NUG heritage contracts were like the Nuclearco PPA and priced entirely in energy, meaning that they must run to cover the capital costs of those generators, of those private power generators.

Later in response to cross by Mr. Gorman, Mr. Kennedy explained -- and I have the transcript reference if we require it -- that the capital costs of the private power producers were netted out in exhibit A-96.

Also, when I looked at A-95 on page 12 I found that Mr. Peaco had netted out the capacity costs of the private power producers at $29.8 million and shown a natural gas cost for these same plants at 95.3 million.

Now these parts of the evidence lead me to believe that the contract between Genco and the private power producers or the contracts between them contain provisions for separating the capacity and energy payments.

This would mean that Genco could pay the private power producers for the capacity and leave them whole in a financial sense and schedule the private power plants in merit order. And in doing that it might save Disco some $95 million.

So my first question I guess is, not just to the panel but maybe to the Chair, do we need to examine the so-called heritage PPAs to determine if Genco can reduce its need for natural gas and still comply with those contract provisions?

Or is there another way that we can clear this matter up so that I can know or we can know definitively whether or not these plants must actually run in order to keep the private power producers whole in terms of their capital cost.

MR. MAROIS: I guess I don't know where to start other than -- what number did you quote in your -- I'm not sure of the question.

DR. SOLLOWS: The only numbers I dealt with came from A-95.

MR. MAROIS: No. At the end you quoted $95 million?

DR. SOLLOWS: A-95 on page 12. That would be --

MR. MAROIS: No. But I thought you said 95,000,000.

DR. SOLLOWS: Yes.

MR. MAROIS: So you are saying saving 95,000,000. I'm not too sure what --

DR. SOLLOWS: In A-95 on page 12.

MR. MAROIS: So what is -- which page?

DR. SOLLOWS: Page 12. Now when I look at that bar chart I see that the capacity cost of the NUGs is listed at 29.8 million. And the natural gas is listed at 95.3.

And so I'm left wondering if we could -- if those contracts don't actually allow us to just pay the capacity cost, and simply schedule them not to run.

We have paid their capital costs. They should be able to get their financing. And we save -- because natural gas is very expensive we can save a lot of money.

MR. MAROIS: Well, I guess from Disco's perspective -- I will bring you to the PPA which is A-4, schedule 6.2 -- sorry, in the Genco PPA.

DR. SOLLOWS: The vesting contract?

MR. MAROIS: Yes. And so in schedule 6.2 there is a Roman Numeral II. And then there is Section (2). So what that section says is for electricity purchase under --

CHAIRMAN: Just a second, Mr. Marois.

MR. MAROIS: Sorry.

CHAIRMAN: Let us get it. So in the vesting agreement what is the reference again?

MR. MAROIS: Schedule 6.2. Well, the schedule is at the end. And it's page (i). So in schedule 6.2 which deals with the calculation of the fuel component of the vesting energy price, there is a section, Roman Numeral II. And then there is subsection (2).

So what that section says is for electricity purchases under the heritage PPAs the energy will be modeled as take or pay. And the purchase price of the PPA expressed in dollars per megawatt-hours will be used to determine the fuel component.

So I mean this is -- this is what we deal with. This is the contract. The contract states that the PPAs will be modeled at take or pay. And that's what we have done.

DR. SOLLOWS: And I saw this as well. And the words that I highlighted when I read this earlier, I guess it was late last year, it says that "Energy will be modeled as take or pay."

It doesn't say that the contracts are structured take or pay with all of the capital in energy price. It says for modeling purposes under the PPA it will be done this.

And again the wording of this leads me to believe that in fact Genco could simply keep the private power producers whole by paying for the capacity and not have to burn the natural gas.

And so it really does leave me questioning whether or not we can cut maybe $90 million out of your fuel price estimate?

CHAIRMAN: The manager is in the dugout. I can see that.

I will ask Mr. Morrison. Mr. Morrison, the contracts with the NUGs of course we don't have them. So we have no jurisdiction, as we have ruled before, over Genco to get them.

I just wonder if this panel could offer up a suggestion on how you can legitimately follow through on Commissioner Sollows' point that he has made and come back to us in reference to that.

MR. HASHEY: Mr. Chairman, maybe if I could speak briefly to this. This was the topic of the discussion that Mr. Stewart was here. And I think in fairness, if we are getting into disclosure of the third party contracts that he should be part of this discussion.

This was something that -- certainly there was an indication that there was nothing that was attempted to be hidden from our group. But there was very strenuous objection which I believe you ruled on as a result of Mr. Stewart's representations to you.

CHAIRMAN: Mr. Hashey, don't misinterpret what I'm saying. I'm trying to find out if there is a practical way that Genco can still be in compliance with the confidentiality provisions, but that this panel can go away and deal with Commissioner Sollows' rather logical questioning, as far as I'm concerned, and come back and assure us (a) it can be done or (b) it can't be done or whatever, to assure the Board that Disco is in fact doing its best to look after the interests of the consumer.

MR. MORRISON: Just so I'm clear, Mr. Chairman, so I understand what the question is, so we can understand whether we can address it. If I understand it the question is not -- we know how the Disco fuel price is set with respect to the heritage PPAs.

It is a question of how -- and it is take or pay as far as Disco is concerned, I guess. It is modeled that way. Is the question whether the contractual provisions between Genco and the Heritage PPAs are on a take or pay basis.

And I know that Commissioner Sollows referred to $95 million in potential savings from gas. But I guess there is an offset to that. Because you have to replace that energy using a different type of fuel or purchases or something.

So I don't know -- is it the question -- is it whether the PPAs themselves vis-a-vis the third parties in Genco are take or pay? In other words, are they obligated to pay the energy component of --

CHAIRMAN: Mr. Morrison, I'm going to try and say it again very simply. We are concerned that Disco should be, in any way that it can, by going back and complaining about certain provisions to the Operating Committee if necessary, et cetera to ensure that the customers of Disco will get the best deal that they can.

I mean, that is part of our responsibility sitting here. We don't have those contracts. We want this panel to go away, not right away, and look at it and find out -- they have access to those contracts or information concerning them -- and see if there is any way that the PPAs could be amended and still the NUG contracts complied with that will pass the savings on to the customers of Disco.

I can't make it any clearer than that. That is certainly from my point of view. Commissioner Sollows may well have more to add to that.

DR. SOLLOWS: I think that captures it. And I'm just left musing here. And I have a question for Mr. Peaco might help clarify this and lead us to a path that will be productive.

In your experience would these kinds of contracts between a private power producer and in this case Genco contain the same kind of confidentiality clause that we find in the vesting agreements, i.e. a confidentiality clause that provides for release to any competent authority or regulatory authority?

MR. PEACO: It wouldn't -- I mean, it would vary from case to case. It depends on the parties and what they agreed to.

DR. SOLLOWS: Mr. Morrison, do you know if these contracts have such clauses in them?

MR. MORRISON: I personally have not reviewed the NUGs. I don't know whether Mr. Hashey has.

MR. HASHEY: I have seen the confidentiality clauses in them.

DR. SOLLOWS: Do they provide --

MR. HASHEY: I have only been supplied with a confidentiality clause when I asked to see that.

DR. SOLLOWS: Do they provide for, as these contracts do, the release of anything confidential to a panel like us?

MR. HASHEY: Well, I think the problem you have, Mr. Sollows -- and this is a Genco contract. And Genco of course isn't administered by the Board. If it was a Disco contract there would be absolutely no question about it. That is the hang --

DR. SOLLOWS: So the contract does provide for its release by Genco if Genco. If Genco wanted to give it to the Board the contract certainly anticipated that it could?

MR. HASHEY: I would have to confirm that. But I believe that that is a pretty standard clause.

DR. SOLLOWS: Thank you. So I will carry on with another line of questioning.

Yesterday we heard in reference to 15 megawatts of hydro generation at Stone Smurfit and 500 kilowatts owned by B.J. Hargrove.

Are these small hydro assets, I guess we will call them, and the wind power you are counting on for 2006/2007 the only electricity suppliers you have in the test year outside of the NB Power group of companies?

MR. KENNEDY: Yes, primarily. There are two other -- it was indicated that we do buy back from time to time from two other sources with respect to our contracts that we have with self-generators where we supply interruptible to those self-generators.

DR. SOLLOWS: What are the two?

MR. KENNEDY: Irving Pulp and Paper.

DR. SOLLOWS: Yes.

MR. KENNEDY: A.V. Cell.

DR. SOLLOWS: A.V.?

MR. KENNEDY: A.V. Cell.

DR. SOLLOWS: A.V. Cell. Okay.

Now does the record show how much energy you expect these four companies to provide and the price that you got to pay for it?

MR. MAROIS: We believe we have provided that information in an information request. We are just going to try to --

DR. SOLLOWS: If you -- I just haven't seen it. Maybe I shouldn't admit to that, but maybe I have seen it and just don't recall. It's a big set of files.

MR. MAROIS: And it's my recollection we provided it. So maybe I am wrong.

DR. SOLLOWS: Okay. Well if you have, that's fine. If you could just put it on the record.

MR. KENNEDY: I'm sorry. Yes, we have. I'm just trying to find the IR.

DR. SOLLOWS: Well we won't waste time right now. You can sort of fill us in later as an undertaking.

MR. KENNEDY: Okay.

DR. SOLLOWS: My question that arises from that is does the price that you are paying represent the full avoided cost as the Act would seem to dictate it should?

MR. KENNEDY: These particular -- particularly the ones the self-generators that are installed behind the meter where those self-generators normally, except for the situation that is occurring up at Stone right now, serve load -- serve load, their own load, and from time to time there is surplus energy that comes out on the system a few hours in a month.

They are compensated -- 90 percent of our avoided costs take into the factor that there is some administration with respect to administrating these contracts. So it's 90 percent of our avoided cost. And in one of the IRs we indicated in one of the years that -- what the amount is and roughly it would be in the range of 35 to $37 I recall per megawatt hour.

DR. SOLLOWS: So how were -- you say you compensate them to 90 percent of the avoided cost. The Act, if I interpret correctly, says if they are connected at the distribution voltage level, and I'm assuming they are --

MR. KENNEDY: These customers are connected at the transmission level. There are large industrial customers who have embedded generators behind our meters serving load.

DR. SOLLOWS: So these are all transmission level customers?

MR. KENNEDY: Yes. Except for B.J. Hargrove.

DR. SOLLOWS: So B.J. Hargrove is a distribution level customer?

MR. KENNEDY: That's correct.

DR. SOLLOWS: And so it would be only B.J. Hargrove that should be compensated at the full avoided cost?

MR. KENNEDY: That's correct.

DR. SOLLOWS: And are they?

MR. KENNEDY: They are under a separate contract that was developed, and they basically are not -- it's a special contract that we had in place prior to restructuring.

DR. SOLLOWS: And now that the Act is in force, and I'm assuming that it's in force, are you revisiting those contracts?

MR. KENNEDY: Yes, we are.

DR. SOLLOWS: Okay. How do you set the full avoided cost?

MR. KENNEDY: With respect to the Disco, anything --

DR. SOLLOWS: Yes. That portion of the Act that requires you to pay it, is there -- I mean, in many jurisdictions there would be a rate -- an avoided cost hearing that would establish this for schedule purposes. Do you anticipate such a process?

MR. MAROIS: Well, this is maybe another area where we will need legal interpretation, but the section of the Act that deals with this is Section 75. And my understanding of Section 75 is the default situation is 75.1 where the utility will free up the rate based on the -- I guess it should be 75.2. 75.2 what it says is if a distributor -- distribution electric utility and a generator referred to in subsection 1 are unable to agree on the rate to be paid by the utility to the generator, either may apply to the Board for a determination of the rate.

So what that tells me is the best case is we try to agree and if we don't then it comes to the Board.

DR. SOLLOWS: So if I understand it you would anticipate negotiating a different full avoided cost on a case by case basis, is that what you are suggesting? Depending on which person walks in the door you will take whatever outcome and that will be called the full avoided cost for that customer?

MR. MAROIS: No. The issue -- I don't think we faced it yet, but the challenge will be -- I mean, it's pretty clear how we would calculate avoided costs. I mean, we would probably use -- using the PROMOD run in terms of what units would be at the margin and all that, so that the general approach is relatively easy. Where it becomes a challenge for example is if a customer wants to -- if somebody wants a contract for a long-term, how do you adjust the -- because what promoters want is some predictability, some stability, and if you base your pricing on actual avoided costs it may fluctuate hour by hour. I mean, that's the truly avoided cost.

DR. SOLLOWS: Do we -- I guess -- and I don't want to labour this point, but do we all have a clear understanding of what is meant by the term full avoided cost? I mean, is that a defined term somewhere? I don't think I found it in the Act.

MR. MAROIS: I don't know. You are asking me a question there -

DR. SOLLOWS: Mr. Peaco, based on your experience would you have any idea what that would refer to?

MR. PEACO: Based on my experience the full avoided cost would have specific meaning in the federal Act in the U.S. --

DR. SOLLOWS: Okay.

MR. PEACO: -- as setting up the avoided cost practices in the U.S. So that would have -- clearly have a distinct meaning in that Act and the FERC and state regulations implementing that Act.

DR. SOLLOWS: That's I guess where I would be coming from as well. So thank you. That's fine for that.

MR. MAROIS: Dr. Sollows, where did you see full avoided cost?

DR. SOLLOWS: Oh, maybe it's just my --

MR. MAROIS: Because 75.3 says the Board shall determine the rate to be paid under this section on the basis of the costs avoided by the distributor. So that word full is not --

DR. SOLLOWS: The Board shall?

MR. MAROIS: But that's if there is a dispute.

DR. SOLLOWS: What is up at the top? What is the first clause?

MR. MAROIS: That's what I'm looking at.

DR. SOLLOWS: I'm going from memory you see.

MR. MORRISON: It's not in the first clause, Commissioner Sollows.

MR. MAROIS: It's not there.

DR. SOLLOWS: Okay. That's my confusion. Thank you for clearing it up. Now in respect of windpower, we were discussing it yesterday. Have you conducted an independent engineering evaluation of the wind energy project to determine the likelihood it will enter service during the test year, and is that on the record?

MR. KENNEDY: No, we have not.

DR. SOLLOWS: Can you undertake to do so?

MR. MAROIS: Well, I'm not necessarily willing to commit to that at this stage. I would need to understand -- we have got projects -- well let me backtrack. For the current year we have got three separate projects included in our forecast, one is Eastern Wind which has been under contract for a while, and so when we did this forecast back in I guess the summer of last year it was clear that Eastern Wind would come into operation in the spring of this year, if I recall.

Now this project has been delayed for different reasons but it's still expected they will come on line this year.

So I guess I'm not sure why would we want an engineering study at this stage to know when it will come into effect, because we have a contract with the promoter and if the project is not -- if they don't meet -- if they don't comply with the contract there is going to be some consequences.

DR. SOLLOWS: It's already -- I guess my reasoning is it's already slipped schedule and my understanding of these things based on what I read is this is not an uncommon occurrence and I'm looking to try and reduce the rate impact for 2006/2007 and I don't want to include in your revenue requirement any revenue that you won't really need.

MR. MAROIS: But the problem, Mr. Sollows, is you can't pick and choose what you modify in our forecasts, because -- I mean, we will probably -- there is many areas in the forecast will be wrong because it's a forecast. So if you want to remove this because there is a risk that might not materialize, I will come up with a list of other things that we need to add because we --

DR. SOLLOWS: And if you do that we will have a long and fruitful discussion I'm sure, but in this particular case you have already told me that the schedule has slipped based from when you made your original plan that led to this budget. And I would like to have some confidence that it's not going to slip beyond the end of the test year. That's where I'm coming from. But if you can't provide it that's fine. We will just carry on to another line.

MR. MAROIS: We don't have such a study.

DR. SOLLOWS: Yes.

MR. MAROIS: One thing that would have to be understood with this renewable projects, if these projects don't materialize we still have to buy the power. So really what we are talking about is simply the incremental price we would pay for the renewable versus the vesting price.

DR. SOLLOWS: Thank you. I would like to move on to the issue of the fuel that's purchased for export sales. And I just want to make sure this is clear in my mind. The first question is, is the fuel that's used to make export sales purchased separately from that for in-province energy?

MR. MAROIS: Can you please repeat the question?

DR. SOLLOWS: Is the fuel that's used or burned to make export sales purchased separately from that purchased for in-province energy?

MR. KENNEDY: There is no line item Genco purchases fuel and on -- for all occasions, whether it be for the in-province load and export, but it's based on the replacement cost with respect to the export and assigned to those various assets that are -- as burnt in those assets that are exporting that are burning for the export market.

DR. SOLLOWS: So is the fuel that is used for the export sales hedged in the same manner that's been described for the fuel purchases for Disco?

MS. MACFARLANE: No, it is not.

DR. SOLLOWS: So we have separate inventories of fuel?

MS. MACFARLANE: No, we don't have separate inventories. We have one inventory of fuel. And the charges of that fuel in-province versus out-of-province are based on dispatch of the units. But the hedges are only purchased based on the forecasted use for in-province.

DR. SOLLOWS: In-province. Okay.

MS. MACFARLANE: And, of course, that's because we aren't in a position to hedge the sale price we are going to get, so we don't want to find ourselves locked into a product price.

DR. SOLLOWS: That was where I was going with this. So the volume of fuel required for export sales depends on future price for electricity and these other risk factors and that would just make it a lot riskier would it not?

MS. MACFARLANE: That's correct.

DR. SOLLOWS: Fair enough.

MS. MACFARLANE: Could I just be a little more specific?

DR. SOLLOWS: Sure. Okay.

MS. MACFARLANE: We don't hedge the export fuel until the sale is made. Once the sale is made and we know the margin, we hedge then and lock it in.

DR. SOLLOWS: Right. So when Genco makes the export sale, it uses its fuel price as opposed to the Disco fuel price in determining whether or not it will make a bid?

MS. MACFARLANE: It uses the replacement fuel price, yes.

DR. SOLLOWS: Yes. That's fine. One last question on this. Are the volume sales estimates for exports on the record now? We have in the PPAs the dollar amounts, but do we have the volume estimates? You remember we have -- we finally cleared up the confusion I think over the data that was filed in response to an interrogatory and the data that is available from the National Energy Board. We may come back to that sometime later. But that's the actual exports. Are the volume estimates, the number of megawatt hours that are -- that form the basis of those -- that five-year export forecast available on the record yet? And where are they so available?

MR. MORRISON: As far as I know, Commissioner Sollows, no, because those numbers are in the PPAs themselves. They are fixed in the PPA.

DR. SOLLOWS: But those are dollar numbers. I am asking the volume of sales in megawatt hours?

MR. MORRISON: There is nothing on the record.

DR. SOLLOWS: Could we have that put on the record, please?

MR. MORRISON: I guess we will have to check to see if it's available.

DR. SOLLOWS: Thank you. If you wish -- I have quite -- I am at page 9 of 24. So if you want to break, this might be a good time. There is only one or two questions on some of the pages.

CHAIRMAN: We will take our lunch break now and come back at quarter after 1:00.

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

CHAIRMAN: Good afternoon, ladies and gentlemen. Any preliminary matters?

MR. MORRISON: No, Mr. Chairman.

CHAIRMAN: No? Anybody -- Mr. Morrison has none. Anybody have any?

MR. MAROIS: Mr. Chair, if I could I would like to make just a comment for the record. I guess following the line of questioning this morning I'm concerned that they might have left the impression that there was a potential saving of $95 million if the natural gas generators were not run. And I want to be crystal-clear that there is no potential savings of $95 million. Because we need the energy.

So if those generators do not run we are going to have to find replacement power which could be cheaper or it could be more expensive.

So I just felt it was important to leave that on the record.

CHAIRMAN: Well, that is fine. But let me just ask a supplemental on that. The odds are they would be cheaper.

MR. MAROIS: I'm not ready to say that.

CHAIRMAN: No?

MR. MAROIS: No.

CHAIRMAN: Okay.

MS. MACFARLANE: If we were to -- there is no other generation in New Brunswick which is why we have contracted with them. So if we were buying we would likely be buying out of New England. And New England is priced off natural gas.

CHAIRMAN: Well, all right. You are going to have a chance to go back and look at things and come back to us and let us know these things.

I'm talking from just an impression. And that is now good. So we are trying to get some facts from the table.

Commissioner Sollows?

DR. SOLLOWS: Thank you. Just to follow up on that. In that regard can I get you to file -- I know you are working on a modified version of A-6 to put the estimated for 05/06 in the column instead of the budget values.

Can I get you to add another column to that indicating the cost breakdowns if all the plants were dispatched on economic merit or for security reasons? And that would help us determine what the incremental cost is one way or the other, would it not?

CHAIRMAN: Some of the NUGs are co-gen. And you wouldn't want to lump them into that.

DR. SOLLOWS: Well, depending upon what the contract conditions are, we may or may not. We don't know is the point. So as a basis of comparison --

CHAIRMAN: I just -- to me the layman, that would be lumping the co-gens in that -- you know, on the economic dispatch end of things.

DR. SOLLOWS: Well, if you want to add in a third column or a fourth column that would be fine too.

CHAIRMAN: Sorry, I --

DR. SOLLOWS: But what I'm trying to get at is the purely -- dispatching the plants and capacity available in the province on a purely economic basis, what would be the estimated cost to Disco?

MR. MAROIS: For what year?

DR. SOLLOWS: For the test year?

MR. MAROIS: I believe we have already answered that in an IR. And I will find a reference.

DR. SOLLOWS: If you could that would be just great.

MR. MAROIS: But again -- and I think we have --

DR. SOLLOWS: But broken out in the detail that we have in A-96.

MR. MAROIS: I don't know if we can do that. We will look at it. I mean, because all these questions are hypothetical. I mean, that's not how the contracts are structured. So that's why sometimes I don't know if certain things can be done or cannot be done. So we will look at it. But I don't know.

DR. SOLLOWS: I guess my understanding was that that is essentially what PROMOD did, was model the dispatch of the plants normally on an economic basis.

And you have to in a sense defeat the system by designating the must run in order to take them out of economic dispatch.

MR. MAROIS: That's what we did in response to an IR. But I don't know if we can provide the --

DR. SOLLOWS: Oh, I see.

MR. MAROIS: -- information in a table like --

DR. SOLLOWS: Whatever you can do would be great, anything to help. Thanks.

Thank you. I think to carry on with the questioning that we left off with before lunch -- make sure I got -- Ms. MacFarlane, under cross examination by Mr. Lawson -- and sorry, I don't have the transcript reference here, but I just cut and paste it -- you said most recently we had an audit done of our hedging program to ensure that it did meet the needs of the utility, that we were following it from a compliance perspective and that it would meet regulatory purposes. And then you -- particularly in light of no speculation, you went on.

Just what do you mean by the phrase "meet regulatory purposes"?

MS. MACFARLANE: The consulting firm that we worked with to design the program indicated that there are regulatory jurisdictions where in fact costs of hedges, not benefits but costs have been disallowed because the utility was taking bets on the market and yet was not in the professional business of being energy consultants and price predictors.

And because those judgment calls were seen as imprudent therefore they were disallowed. So the consultant suggested that the programs that typically are more sound from a regulatory perspective are ones where price views are not taken.

DR. SOLLOWS: Okay. Thank you. Now I know we dealt with this issue earlier. And I had a few prepared questions. And then as the discussions ensued I made some more. So I want to talk briefly about the hydro adjustment I think Vice-Chairman Nelson was questioning you on earlier this morning.

Mr. Kennedy, is it -- in my mind, I think I heard that you represented Disco's interests in the Operating Committee deliberations in respect of the change in the calculation method, is that right?

MR. KENNEDY: Yes. I'm a member of the Operating Committee that was --

DR. SOLLOWS: Yes. What arguments did you present on Disco's behalf and in defence of the original method of calculation?

MR. KENNEDY: The arguments that I presented were that -- I convinced myself that -- I put on the table first of all the question why they were recommending that we change, and requested they explain in detail with respect to what their rationale was, and took that into consideration in making a decision where the Operating Committee came to a consensus to make the change.

DR. SOLLOWS: Okay. Ms. MacFarlane, you referred to in your response early this morning to an analysis. Is that analysis on the record?

MS. MACFARLANE: I don't think so.

DR. SOLLOWS: Can it be put on the record? I know the minutes also refer to an analysis that would document the decision sort of after the fact. I'm assuming there must have been something before the fact. And I'm just wondering if we can get that on the public record?

MS. MACFARLANE: What I'm not sure of was whether the analysis was conceptual or whether in fact it was numeric. Because I would have been monitoring the work of the committee. But I wasn't on the committee. So we will look at that.

DR. SOLLOWS: Could you undertake that?

MS. MACFARLANE: Yes.

DR. SOLLOWS: Thank you.

MS. MACFARLANE: I would point out a well that one of the -- we too were thinking about the discussion this morning. And to the extent that when hydro is high, the use of the initial methodology put a high credit through to Disco and one that was anomalous with the way the original hydro was modeled in PROMOD.

The opposite would be true if hydro was low. And there would be too high a penalty to Disco --

DR. SOLLOWS: And that is one of the reasons why I would like to see the analysis, the details of the analysis, to help judge that.

MS. MACFARLANE: Okay. Thank you.

DR. SOLLOWS: Thank you. You also triggered to this problem when you saw the monthly balances growing ever larger when it was done, the calculation was done. Are those monthly balances on the record?

MS. MACFARLANE: No, they are not. Because when the correction was made it was corrected retroactively.

DR. SOLLOWS: Okay. So you have no record of what those balances were leading up to the decision to correct it?

MS. MACFARLANE: Not on the record, no.

DR. SOLLOWS: Okay. Would it be inconvenient to provide it? Or maybe an estimate of the value?

MS. MACFARLANE: The total amount of the hydro adjustment was probably mentioned in the Operating Committee meeting. But we can provide that information.

DR. SOLLOWS: Okay. Thank you. I guess my next question comes down to again this thorny problem we are all grappling with, is what was in the mind of the people or the drafters of the PPAs?

And I'm asking myself, and I'm going to ask you, isn't it likely that the drafters of the PPAs anticipated that the calculation would be done in the way you were originally doing it?

It is the way you started doing it once you were given the PPAs. First instinct would seem that that must be what they had in mind when they drafted it. So I'm wondering if maybe the original calculation was what they had in mind?

MR. MAROIS: They would not have gone to that level of detail. I mean, again I think the spirit of how the calculation -- or what the calculation is trying to achieve was built into the PPA. But the mechanics, I don't think that that was contemplated.

DR. SOLLOWS: Okay. Thank you. One final question on this. Are there any other places where changes have occurred to the methods of calculation that were initially applied under the PPAs other than the hydro adjustments?

MR. KENNEDY: Nothing comes to my mind right at this moment.

DR. SOLLOWS: Okay. Well, if you want to think about it and something comes up, if you could, just to complete the record would be great. Thank you.

Now I want to move on to reference A-95. That is the slide show of the La Capra report. And I'm on page 15 in A-95.

Now the slide illustrates that the capacity that's labelled as base/must run is slightly more than 2000 megawatts of New Brunswick's generation mix. Schedule 1.1.67 of the vesting agreements shows baseload assets of 2445.1, or that may be 25-something now. Can you explain the reason for the discrepancy?

MR. PEACO: There is a couple of differences here. One is -- this was shown to look at the operating mix of the total Genco system including the Point Lepreau asset which is not listed in schedule 1.1.6, and also I think Coleson Cove is actually included in the total. And so the difference between the Point Lepreau capacity and Coleson Cove would explain the numbers you are looking at.

DR. SOLLOWS: Okay. That I guess makes sense. I hadn't picked up on that.

MR. PEACO: This was sort of more in terms of how they are operated in the system rather than how they are --

DR. SOLLOWS: Understood. It makes perfect sense now. I just hadn't picked up on it. Thanks very much.

Now, Ms. MacFarlane, in response to a question from Mr. Coon earlier this week -- and I think he was wondering about exports from the Point Lepreau station either before or after refurbishment, you said that -- I think you indicated it would be an unusual circumstance and you said that base load even in the summer months seldom gets below

1800 megawatts, and went on to say Lepreau being must run at 635 megawatts it would all be used in-province.

Now I found your reference to 1800 megawatts as base load a little curious because in preparation for this hearing I examined the data that NB Power or Disco provided in response to PI IR-5 which was hourly load data -- spreadsheet of hourly load data for five years. I did this by preparing an annual load duration curve for the test year using the average of the five years data that you provided to estimate the shape.

I then applied the definition of base load that NB Power gave this Board in the generic hearing on capacity planning in the early '90s, which was 70 percent.

As a result I found the base load for the test year will be about 1600 megawatts, not 1800 megawatts. And that left me with this question. Does the 1800 megawatts you cite include 200 megawatts of interruptible load that's there on the summer?

MS. MACFARLANE: No, it doesn't. It was an estimate and I think your number is probably more accurate.

DR. SOLLOWS: Okay. So in fact the base load for the system in the test year is more like 1600 megawatts?

MS. MACFARLANE: Probably.

DR. SOLLOWS: Thank you.

MS. MACFARLANE: I was just trying to make the broad point that that's a long way from what Point Lepreau --

DR. SOLLOWS: Yes. Oh, understood.

MS. MACFARLANE: Yes.

DR. SOLLOWS: Thank you. So carrying on now. Mr. Kennedy, earlier -- and I apologize, I don't recall who was questioning you, but you were asked about the source of the number 0.565 in reference to the vesting agreement Article 3.1.2.

And I take it this is the factor that is multiplied but the number of hours in a year and then multiplied by the base energy or the nominated capacity in the vesting agreement to determine your energy entitlement?

MR. KENNEDY: That is correct.

DR. SOLLOWS: Okay. Now I confess that my notes were really quite confused at that time. I heard reference to energy entitlements, to simulated capacity factors, and I heard that the market design committee provided the number. What I did not hear is any reference by you or by Ms. MacFarlane to Disco's load factor. When I examined that same data from PI IR-5 the first thing I did was estimate the load factor for the five years that you had provided, and I got values ranging from 53.6 percent up to 60.5 percent. And they had an average of 57.3 percent.

So my question is, do you suppose that the 56.5 percent that is referenced in Article 3.1.2 of the vesting agreement was really meant to represent the average load factor for Disco?

MR. KENNEDY: I have -- I'm not sure, but if you have -- I have been trying to get back to this IR, I'm not sure you have it. I know it's been -- in another earlier session it was -- it's Disco PUB IR-83, July 14th.

DR. SOLLOWS: What exhibit?

MR. MORRISON: I believe it's exhibit A-12.

DR. SOLLOWS: Okay.

MR. KENNEDY: But if you don't have it I will start through this. It explains the derivation of the energy entitlement. And reference -- I reference with respect to the market design committee the final report April 2002. The reference in there to supply all in-province load a system load factor of 61 percent, and it's in recommendation 4.34.

So with respect to that, if you take Genco's assets that we have been talking about of 2425.1 as a heritage asset, and then you add to it another heritage asset which is Point Lepreau at 605 megawatts, that's the entitlement piece that comes to the in-province load. You add those two components together and you come up with 3030.1

megawatts of heritage assets, using the prescribed nominated capacity of 2425.

And applying a 61 percent capacity factor to that number times 8760 hours in a year, you come to 61 percent times 3031.1 megawatts times 8760 hours in a year, and then you come to a number that basically comes to 16,200 gigawatt hours that is from the heritage assets available for the in-province.

And then you back out Point Lepreau at 80 percent, 4240 or 4200 gigawatt hours, and you come to the 12,000 gigawatt hours, or the 12 terawatt hours, that is in the contract as the energy entitlement.

DR. SOLLOWS: Right. And that's where the .565 comes from?

MR. KENNEDY: And then you back-calculate using 2425 times 8760 -- just back calculate --

DR. SOLLOWS: Okay. That clarifies matters. So it really is load factor based on -- for the system load?

MR. KENNEDY: It was to represent what was required to serve the in-province load in the Province of New Brunswick which includes firm in-province as well as interruptible and surplus.

DR. SOLLOWS: Thank you. Okay. So that helps me a lot and it actually places me right where I was as I was thinking of this, and it led me to think about the consequences of load factor improvement.

So would you agree with me that a capital intensive like Disco would benefit from increases in load factor in the same -- in that the same capital investment delivers more energy for the same demand as load factor increases?

MR. MAROIS: Could you repeat that a bit slower, please?

DR. SOLLOWS: Okay. Disco like many other capital intensive businesses presumably looks at its load factor and it has to invest capital to meet the peak demand, but a lot of its revenue flow is based on the energy that they are billing. And so as a global measure of performance you would look at load factor and you would really want to -- I mean, often conduct programs to improve your load factor, to increase it, giving better utilization of your assets.

Would you agree that that's sort of a reasonable approach to take?

MR. MAROIS: Yes, I would agree with your premise. I guess us in New Brunswick we have been fortunate that we have been able to sell the excess to compensate the fact that you need to plan for the peak, but generally speaking you are correct.

DR. SOLLOWS: Okay. Suppose you could undertake a program to increase your load factor to 65 percent while holding your demand constant at the test year value of 3200 megawatts.

My question is how would the PPAs treat Disco in this event? Would they provide Disco with a reasonable incentive to do the work or would they provide a disincentive or would they be neutral?

What would be the consequence of increasing your load factor to 65 percent while leaving your demand at 3200 megawatts for the test year? How would that flow through the PPAs and affect your bottom line?

MR. MAROIS: I guess we didn't have a chance to do a thorough analysis. But I guess one of the first things that comes to mind is, everything else being equal, the PPAs would allow us to reduce the capacity nomination, if the need for capacity reduces proportionately.

DR. SOLLOWS: In this case I'm assuming that you are going to have to -- your demand is constant at 3200 megawatts. So you need the same capacity. But you have undertaken a load improvement program or load factor improvement program. You have improved your load factor to 65 percent.

My question -- and if you can't answer it here now on the spot that is fine. If you would just undertake to provide the answer.

My question is should you be in the happy circumstance that most capital-intensive companies would like to find them, with load factor improvement, how does that flow through the PPAs to affect Disco's bottom line?

And I understand, if you can't answer it here now, if you would just undertake to provide the answer.

MR. MAROIS: I think it's best to undertake.

DR. SOLLOWS: Probably. Thank you. Now in a somewhat related item, on A-96, that is the legal sheet that we have showing the power purchase cost variance. Line 4 on that refers to -- oh, no, I have got that wrong. There is a reference here somewhere. Yes, it is line 12 refers to CT operation and emergency purchases.

Have all the interruptible loads been interrupted prior to making emergency purchases or dispatching combustion turbines?

MR. KENNEDY: Yes. Generally that is the case. It depends -- it would be in all -- in I would say the majority of circumstances the CTs -- all the interruptible load and surplus load would be interrupted prior to running CTs and emergency purchases.

But again the way the pricing is, if we know a day in advance, when we provide the price, and the customer wishes, and he sees the price signal, he can buy through it, provided the supply is there and can be purchased.

DR. SOLLOWS: But in the case of an emergency purchase you are in a state where you have disconnected the interruptibles I would assume?

MR. KENNEDY: Oh, yes, yes, yes.

DR. SOLLOWS: Okay. Thank you. Now I think that is it for that one. Making good progress. Now, Ms. MacFarlane, if I recall correctly from yesterday's hearing -- I can't recall who was examining you -- but you were asked to explain why the CPI adjustment on the contribution to fixed costs in the vesting agreement was set at the full CPI for three years and then at one-third of the CPI thereafter.

And I got the impression that you were at a loss to explain why, and you said well, that is what the agreement says. Is that fair?

MS. MACFARLANE: It's not unfair.

DR. SOLLOWS: No. Okay.

MS. MACFARLANE: There was an exercise that the modelers went through that they referred to as shaping, so that over time costs were collected but were in some instances eased into. And I assume that was part of the shaping.

DR. SOLLOWS: Mr. Kennedy, did I understand correctly that you had some experience on the Generation side prior to joining Disco?

MR. KENNEDY: Yes. That's correct. I was a Air Generation Manager in the northeastern area for 15 years, Station Manager.

DR. SOLLOWS: Okay. So you would have experience and knowledge of maintenance budgets in generation plants and the problems you sometimes have in matching the dollars that Ms. MacFarlane will let you spend to the long list of projects that you would really like to undertake?

MR. KENNEDY: Yes, I do. I would rather forget about it though.

DR. SOLLOWS: I can believe that. And I think that pretty much confirms where I'm going with this.

The next question I was going to ask is would I be right to assume that the financial constraints felt by the integrated company leading up to the restructuring might have had a negative impact on maintenance budgets, and maybe the maintenance budget wasn't as large as you might wish it to be as a good prudent conservative Plant Manager?

MR. KENNEDY: My experience, and in being close to Genco, I don't consider that to be the case. They have a very intensive maintenance program that basically is scrutinized by independent insurers, boiler equipment insurers.

And they take on -- they are very prudent with respect to the way they do their overhauls on a timely basis.

DR. SOLLOWS: You are coming right to the point that I was sort of leading to here, is that really if I have a limited amount of money and I'm responsible for an asset, I will put my highest priority maintenance that leads to -- related to safety and security of the asset. And I will put things like heat rate improvement projects a little bit lower on the priority list. Would that be fair?

MR. KENNEDY: I wouldn't say that. Because basically the heat rate is fixed with respect to the PROMOD. And if they can make improvements on that it would stay in Genco's --

DR. SOLLOWS: I guess that is what I'm getting at. My sense is that there might well have been a financial constraint on the integrated company that would have caused on the generation side some deferred maintenance.

And that might be an explanation as to why the contracts were structured to give you a little bit more money in terms of the increase earlier on in recognition of that and allow the generation side to undo some of the backlog on deferred maintenance.

Now I'm certainly not suggesting that safety or reliability-related maintenance would be deferred. But you can run feed water heaters with plugs in them up to a certain value. And you can run condensers with plugs in them up to a certain value. And it really has no impact on safety or reliability. It just lowers the heat rate. And again my concern is that we have heard again and again a reference to the PPAs being based on historical heat rates.

And I'm worried that maybe those historical heat rates are unduly low because of this perhaps lower priority for heat rate improvement projects, and in fact that there is some really low-hanging fruit for Genco to benefit at the expense of Disco by simply undertaking heat rate improvement projects that they had deferred prior to restructuring.

So how can -- is there any way you can give me some confidence that this is not the case and that really the historical heat rates we are using in the PROMOD calculation are what is reasonably achievable for a well-maintained and well-operated plant with the normal level of heat rate improvement projects over its life?

MR. MAROIS: Well, I think, Mr. Sollows, this is getting to the reasonableness of the numbers in the PPA. And I guess my understanding of the PUBs last decision is we were not going to be cross examined on that. I mean, because we don't have the -- you are making --

DR. SOLLOWS: Are the heat rates in the PPA? I didn't find them there.

MR. MAROIS: They are built into the PPA calculation. I mean, they stem from the PPA calculation.

DR. SOLLOWS: I didn't find the actual heat rates in the PPA.

MR. KENNEDY: The heat rates are prescribed in the PROMOD run.

DR. SOLLOWS: Right. Which is not in the PPA. Those are adjustable depending upon what the historical heat rate is?

MR. KENNEDY: We would monitor those to see that they remain fixed from year over year.

DR. SOLLOWS: Okay. And so in terms of -- when we said that they were based on historical figures, what exactly does that mean? That means the history of qualification tests?

MR. KENNEDY: Yes, heat rate tests that have been done, you know, prior to October the 1st and before the contracts, before the market was --

DR. SOLLOWS: And you have those -- I see in the reference in the PPAs that you have the right to and have copies of those in your possession?

MR. KENNEDY: I have seen and I have copies in my possession.

DR. SOLLOWS: Yes. Okay.

MR. KENNEDY: That is very sensitive information. But I have seen them.

DR. SOLLOWS: So you do have those heat rate -- the heat rate information?

MR. KENNEDY: Yes.

DR. SOLLOWS: Okay. So you could file it with this Board under Section 133?

MR. MORRISON: That is the confidentiality provision?

DR. SOLLOWS: Yes.

MR. MORRISON: We could.

DR. SOLLOWS: If you would please.

MR. MORRISON: But -- and not to rehash Section 156 again, Commissioner Sollows. But it is of no consequence to this rate application

DR. SOLLOWS: It may well be. We will leave that then.

MS. MACFARLANE: Mr. Sollows, could I just make a comment on your --

DR. SOLLOWS: Sure.

MS. MACFARLANE: -- premise behind the question, that being that there was more financial pressure prior to restructuring?

I would suggest that most of our operating managers would tell you that they are under significantly more financial scrutiny and financial pressure post restructuring. Because we have specific targets that we are trying to achieve.

And I think somewhere early on in the policy panel here I made the statement that NB Power was all about safety and reliability before restructuring. And it has been quite a culture change to balance safety and reliability concerns with economic concerns.

And I think most Plant Managers would suggest there wasn't deferred maintenance but there might be in the future.

DR. SOLLOWS: Thank you very much.

CHAIRMAN: Mr. Morrison, I'm going to take a little bit of umbrage with what you just put to us. Because of 156 it doesn't have an impact on this particular rate proceeding. However, we are continuing to be the regulator of Disco. And it may well set the stage for the next appearance or assist in setting the stage for the next appearance in front of this Board in filings, in studies, whatever.

So on that basis, if it is available -- Commissioner Sollows has asked for it -- you can certainly file it on pink paper. And it will be treated in confidence.

MR. MAROIS: Mr. Chair, I was reminded by Mr. Kennedy that we did provide this to the Board. If you recall we provided a binder of detailed PROMOD inputs that you put in your data room or --

DR. SOLLOWS: So it is in that. And I just got the CD today of the extricated version of it. So I will find the stuff there when I need it. Thank you.

CHAIRMAN: We are going to have to put a light in that room.

MR. KENNEDY: Just to confirm, it is in that document.

DR. SOLLOWS: Fair enough. Thanks very much. Then you don't need to file anything separately.

I would like to move on now to the undertaking regarding surveys and it has the exhibit number A-99. And this was undertaking number 5, dated Thursday February 9th, requested by Mr. MacNutt. And, Mr. Marois, you were responsible for it.

MR. MAROIS: I have got that.

DR. SOLLOWS: Okay. Does the script that was used in the survey appear anywhere in the record at this stage?

MR. MAROIS: No.

DR. SOLLOWS: Can you provide that?

MR. MAROIS: Yes.

DR. SOLLOWS: And what was the total cost of conducting the eight surveys?

MR. MAROIS: I don't know that.

DR. SOLLOWS: Can you provide an estimate?

MR. MAROIS: Just for those eight surveys.

DR. SOLLOWS: Well those are the ones in front of us. If there are a lot more that would be material in terms of the cost, I mean I would like to know how much you spend on this activity in a typical year and what you are planning on spending on the activity in the test year.

MR. MAROIS: I can do that.

DR. SOLLOWS: Thank you. I now want to move on to a different topic, and there was considerable discussion about how the shortfall price for energy shortfall out of the Lepreau generator was calculated. I think it was yesterday. And frankly I'm still confused.

So let me say what I think I heard and then give you an opportunity to correct me. I think I heard that Disco pays Genco the Nuclearco price for the energy that Genco provides in relation to any shortfall of production from Neuco, is that correct?

MR. KENNEDY: That's below the 80 percent.

DR. SOLLOWS: Right. The shortfall.

MR. KENNEDY: Yes.

DR. SOLLOWS: Okay. But the Nuclearco PPA is priced entirely as energy, so it's price includes payment for Nuclearco's capacity, but Genco will more than likely given the nature of the capacity excess on the system be satisfying a shortfall from capacity that Disco has already paid for under the vesting PPA. So my question is doesn't this effectively charge Disco double for the capacity that is used to satisfy the shortfall?

MS. MACFARLANE: Good question.

DR. SOLLOWS: Thank you.

MS. MACFARLANE: In the vesting contract you will have noticed that there is an energy entitlement and that Disco pays Genco the vesting price for the energy entitlement. Anything over the energy entitlement Disco pays at market price and that's because in order to provide that Genco is obviously having to pull itself out of the export markets where it would be selling at market price.

When the contractual commitment was designed to provide backstopping for Lepreau, the Lepreau price was picked as a proxy for market, because obviously Genco was going to have to in order to backstop Lepreau. It was going to have to pull out of the export markets. So normally the contract would say you pay at market price, but the Lepreau price was picked as a proxy so as to keep Disco whole, because Disco was already prepared to pay Lepreau the first tier price, and that's the maximum amount that Disco is at risk for when Lepreau doesn't perform.

DR. SOLLOWS: Then the question that arises in my mind is that certainly when I look at the price record on the residual market in ISO New England, sort of the market price as published, there seem to be substantial times of the year when that price is well below the Nuclearco price. And so really in those cases it would be disadvantaging Disco because you are paying -- you could have simply satisfied it at market price which would be a lot lower.

MS. MACFARLANE: I'm not sure that we are looking at the same records, but my experience doesn't show particularly in the last year that market prices are often much lower than that, but that is so.

DR. SOLLOWS: No, I would agree, particularly in the last year --

MS. MACFARLANE: Yes.

DR. SOLLOWS: -- but certainly going over the historic record that goes back I think to '97 in that market --

MS. MACFARLANE: Yes.

DR. SOLLOWS: -- there are numerous instances where the price is running at two and three and four cents a kilowatt hour Canadian, or five cents. So it may well be cheaper to do it in another way. But I guess what you are saying is given the nature of the uncertainty in going to this market model this was sort of the best proxy that you had, is that fair?

MS. MACFARLANE: That's my understanding of what their intent was. I know that I often heard the financial advisors speaking about their own forecast of future market prices and they believed that Lepreau would be at or near what the market would be.

DR. SOLLOWS: Okay. Thank you. One final question on this line, Mr. Chairman. What is the actual capacity factor to date for the Lepreau station for this year, 2005/2006?

MR. KENNEDY: Subject to check I think it's running around 78 percent.

DR. SOLLOWS: 78 percent. So we are -- we have got about 2 percent of the energy there that is subject to this payment, is that --

MR. KENNEDY: That's correct.

DR. SOLLOWS: Okay. Thank you.

CHAIRMAN: Okay. We will take our break.

(Recess)

DR. SOLLOWS: I guess I am under orders to proceed with all due haste. I would like to refer to A-107, which was undertaking dated Monday, February 13th. I guess I asked it. And Mr. Marois, you provided it. A-107 relates to the tie-line. And I had asked you to provide the reports or studies underlying the work for the proposed to establish the 400 megawatts was significant enough to form the foundation of a market. You have indicated that there were no studies to determine that and you point out that the actual physical capacity of the line is 1000 megawatts, but it's limited to 400 megawatts because of system constraints in southern Maine.

So my first question is, when is the expected in-service dates for what we termed as the enhancements to the transmission system in southern Maine that would allow the second tie-line to be used to its full capacity for imports?

MR. MAROIS: I guess this is going to be my third strike, because I have tried to answer twice this question.

DR. SOLLOWS: Well no, you have answered it, but it's leading me along to a different --

MR. MAROIS: Yes. I don't know that.

DR. SOLLOWS: Could you find out?

MR. MAROIS: Yes.

DR. SOLLOWS: I think it's quite relevant. What alternatives to pre-building -- again you may have to check on this. What alternatives to pre-building the full 1000 megawatt line was considered -- or were considered?

And the third question, was there a proper incremental cost benefit study completed to support the selection of the 1000 megawatt capacity, and if that is the case can you provide that? And I don't expect an answer here and now, but -- thank you.

MR. MAROIS: Yes. I believe Mr. Kennedy has a clarification for you.

DR. SOLLOWS: Okay.

MR. KENNEDY: Yes. The question was with respect to Point Lepreau's capacity factor.

DR. SOLLOWS: YEs.

MR. KENNEDY: As of the end of January it was 76.2 percent and it's forecasted for the end of the year to be at 77.3.

DR. SOLLOWS: Pretty close to what you had said, 78, yes.

MR. KENNEDY: Yes.

DR. SOLLOWS: Thank you. Moving on. Mr. Kennedy, in discussions surrounding the status of the Millbank -- the two Millbank units that were sold, you indicated that they were sold because two large industrial customers planned to move off the system. What did you mean by move off the system?

MS. MACFARLANE: I believe that that was a statement from me, Commissioner Sollows.

DR. SOLLOWS: Oh, I'm sorry. Okay.

MS. MACFARLANE: At the time that those decisions were made there was some anticipation that at some point in time industrial and wholesale customers would be able to leave and that they would leave. And so the load forecast of the day had a factor in it on the assumption that customers would leave. It was not specific to any particular customers, it was just a broad assumption.

DR. SOLLOWS: Just sort of a planning assumption.

MS. MACFARLANE: That's correct.

DR. SOLLOWS: And by leave the system you meant contract with another generator?

MS. MACFARLANE: That's correct.

DR. SOLLOWS: Okay. Now in the CARD portion of the hearing, we heard that large industrial customers such as that typically have high load factors and are largely served by base loaded plants. The Millbank plants on the other hand are peaking combustion turbine units. I would like you to explain how the presence or absence of two high load factor customers is relevant to the decision to keep 200 megawatts of combustion turbine peakers?

MR. KENNEDY: In doing the load forecast these loads would be in there with respect to a requirement to serve them from a capacity point of view. So these peakers are primarily there for the option to provide capacity when there is a shortage of generation during the winter months, as well as to provide any necessary operating reserve that may be required to serve because there is a combination of both, the obligation to serve firm load as well as the requirement to provide the necessary operating reserve. The load forecast would indicate that those requirements were there because these industries again are there at the peak, at the time of peak.

DR. SOLLOWS: Okay. So these were large industrial customers that were entirely on firm service and not on interruptible service?

MR. KENNEDY: That is correct.

DR. SOLLOWS: Okay. As a planning assumption. Now, Ms.MacFarlane, did the sale and re-purchase transactions on these two units change the book values of the assets at all?

MS. MACFARLANE: Yes, it would have.

DR. SOLLOWS: Increase or decrease?

MS. MACFARLANE: I believe it was a decrease.

DR. SOLLOWS: Okay. And all of that has been factored into whatever was the fixed charge basis that we discussed earlier for Genco, so we have got it booked at the lower value?

MS. MACFARLANE: That's correct.

DR. SOLLOWS: Okay. Thank you. Now currently are all of the Millbank units in the St. Rose unit bolted down, hooked up to the system and ready to generate?

MR. KENNEDY: Yes, they are.

DR. SOLLOWS: Okay. So they are fully functional and ready for dispatch. Now what I am intrigued by here is you removed them from the system prior to any industrial load being shed. So I would infer from that that you didn't need that 200 megawatts to serve the industrial load that eventually didn't leave because it was already there. So I am inferring from this that you have got at least 200 megawatts of capacity that's not really used and useful from Disco's perspective. Am I wrong?

MS. MACFARLANE: While they look for specific details I will mention that these transactions, the sale and then the subsequent purchase took place some time ago. And I think what my colleagues are looking for is the load growth over a period of time.

So though they may have been determined to be surplus at the time, they would not be surplus at this time. I will just wait for my colleagues to complete the answer.

MR. KENNEDY: We basically are showing from a load and resource balance point of view in our business plan for 2005/06 to 2007/08, January the 17th 2005, exhibit A-87.

It does indicate that basically from a load and resource balance point of view that we are -- at this particular time. Again these studies are updated. But at that time, and it continues that we do have a surplus of capacity to serve our needs.

But as we move out towards the Point Lepreau refurbishment we are going to be deficient with respect to capacity.

And beyond that there is a requirement out -- there is a requirement continues on where it shows some surplus.

But the latest resource balance from a check point of view shows that we are starting to get rather tight out beyond, towards as we approach 2013 and 2012.

DR. SOLLOWS: And I guess we will be dealing with that in the load forecast portion of the hearing that comes sometime later in the spring. So I don't want to dwell on that.

But certainly for the test year it looks like we have surplus and therefore could at least in theory reduce the nomination.

MR. MAROIS: If we could reduce the nomination and increase it, yes, in theory we could.

DR. SOLLOWS: Well, you could also go to the market later, right?

MR. MAROIS: Oh, yes.

DR. SOLLOWS: Okay. Thank you.

MS. MACFARLANE: I just want to clarify that the sale of those units was in 1999/2000.

DR. SOLLOWS: Okay. Thank you. Now there were some questions I think from Board Counsel yesterday about the Coleson Cove precipitator and the upgrade that was necessary to produce marketable gypsum.

What -- I don't know whether this question was asked or not or whether it was answered. But just so that I'm sure I get the information, what plant capacity factor was the precipitator upgrade case based on?

MR. KENNEDY: The precipitator upgrade was based on each unit which the capacity of each unit is 326 megawatts.

DR. SOLLOWS: Well, what capacity factor? How much -- I mean, the amount of gypsum depends on the megawatt hours --

MR. KENNEDY: Yes.

DR. SOLLOWS: -- not the capacity.

MR. KENNEDY: Based on the 2000 tons of producing -- 200,000 tons of gypsum annually.

DR. SOLLOWS: And so what capacity factor does that imply for those units?

MR. KENNEDY: The actual -- I will have to check the actual capacity factor with respect to the total output. There is in-service capacity factor. There is also a forecast of the amount of capacity that's sold into the export market. I'm just not sure.

DR. SOLLOWS: Okay. If you could split it out that would be great.

MR. KENNEDY: Split it out?

DR. SOLLOWS: Yes.

MR. KENNEDY: Okay.

DR. SOLLOWS: Thank you.

MR. KENNEDY: For the test year?

DR. SOLLOWS: Yes, for the test year.

MR. KENNEDY: Okay.

DR. SOLLOWS: That is fine. Thank you. The second question -- the last question on that is at what landfill cost would you have been indiffered between making the upgrade or landfilling the gypsum? Sensitivity on your economic analysis is what I am coming to. And if you don't have that you can provide it as well later.

MR. KENNEDY: The analysis was done on $50 a ton of disposal and trucking costs to the landfill.

DR. SOLLOWS: I'm aware of that. And I guess my question is how low would that price have to fall for you to be

indifferent between doing the upgrade or just landfilling it? And did you test the sensitivity? And if you didn't could you just do that and let me know?
MS. MACFARLANE: That analysis was done. I just don't recall the numbers.
DR. SOLLOWS: If you could just undertake to provide it?
MS. MACFARLANE: Yes.
DR. SOLLOWS: Thank you. Now talk fuel surcharges. Do I understand it correctly that Disco originally sought a fuel surcharge for their rate that would pass through the changes in fuel prices to the electric city rates automatically, and by originally I mean back last spring? Or maybe I misheard and you were planning on doing it, but the plans changed. Have I got it more or less right?
MR. MAROIS: When we had filed -- initially filed our application, it was for 05/06.
DR. SOLLOWS: Yes.
MR. MAROIS: And we had a proposal for a fuel surcharge at the time.
DR. SOLLOWS: Yes.
MR. MAROIS: And the main purpose was to try to deal with the fuel surcharge expeditiously. And what was proposed at the time was an expeditious way to reduce the fuel surcharge, but I guess we had concluded that an increase

in fuel surcharge would probably require an indepth review by the Board, because of the 3 percent provision.

DR. SOLLOWS: Okay. And we understand from this proceeding that your fuel costs are fixed six months prior to the rate hearing. Now that's pretty clear on the record now?

MR. MAROIS: Yes.

DR. SOLLOWS: So my question is if your fuel prices are fixed six months in advance, I am not clear why you would either want or need a fuel cost adjustment clause in your rates? You would -- I would expect that you would just regularly schedule a rate review hearing with this Board for November, December and in two or three days a quick review of the assumptions and the parameters and determinants and we would be done. So why the -- why look for a -- where in a position where you know your fuel costs well in advance of the test year, I am not sure I understand the whole rationale for a fuel surcharge?

MR. MAROIS: Well, we are not asking for one now.

DR. SOLLOWS: Okay.

MR. MAROIS: So I guess that supports your position. And the second part is I really like your two or three days. So if we could do that --

DR. SOLLOWS: I am trusting we can all learn from this process.

MR. MAROIS: I hope so.

DR. SOLLOWS: I will move on. And I am coming very close to the end. Now when I reviewed the vesting agreement, I think I found in Article 2.7.3 -- and I will -- that's in A-4 I think, exhibit A-4, Article 2.7.3. I could be wrong.

MR. MAROIS: Do you mean 2.7.3 or --

DR. SOLLOWS: 2.7.3, exactly. That's what I have written down anyway. Yes. When I read -- oh, I am sorry, slow down. You have it? Okay. When I read Article 2.7.3, it -- I read that Genco -- I will read it completely. "Genco may make firm export sales of excess capacity provided that in order to enter into such firm export sales contracts, Genco must first obtain Disco's prior written consent, which consent shall not be unreasonably withheld or delayed." Has Genco sought your consent for any such contracts?

MR. KENNEDY: None with respect to those type of contracts, which are firm.

DR. SOLLOWS: So there are no existing firm export contracts?

MR. KENNEDY: The contracts that are in place basically can be interrupted without using a pro rata basis where the appropriate load is reduced in New Brunswick versus wherever this export is occurring. Most of the exports -- the exports typically are financially firm and Genco has an obligation to haul those back and make other arrangements from a financially firm point of view in the appropriate market where that is happening. They have to provide by buying out of the market.

DR. SOLLOWS: So under -- there are no contracts that would be considered firm under Section 2.7.3 existing?

MR. KENNEDY: Other than the commitment that we have with respect to Hydro Quebec, which was grandfathered.

DR. SOLLOWS: Yes.

MR. KENNEDY: And that's backed up by the two Millbank units. It's backed up by that capacity that we are not able to claim as capacity as meeting our firm load and reserve commitments.

DR. SOLLOWS: Thank you. Now, I would like to refer to copies of some journal papers that I -- were subject to my review in preparing for this hearing. I will ask the Secretary to distribute them. And I think maybe we will keep it simple. We will just do them one at a time or do you want them both at the same time? There you go. I will start with -- as I said before, one of the things that I do in preparation for this is review literature. And I just want to make sure you have an opportunity review and comment on some of things that I might have read.

I am sure the Chairman will attest to the fact when he looks at my office that this -- there are certainly a pile of papers there. These are just two out of the pile. But there are others, but I have selected these two, because they deal particularly with purchase power contracts.

And I am looking at the paper entitled "A Simplified Procedure for Costing the Financial Risks of Purchased Power Contracts" by a Bill Tye and Marvin Hawthorne. It appeared in The Electricity Journal.

On the last page of that just jumping to the conclusions, rather than getting immersed in all of the details, the authors conclude that, purchased power contracts entail financial risk to electric utilities because their inflexible payment mechanisms involve debt-like obligations. When a utility pursues its own construction program, it incurs risk and expects to recover the cost of this risk from ratepayers. Some of these risks are borne by investors in the purchased power contracts, and they are entitled to compensation for bearing these risks if they are qualified to receive avoided costs. However, investors in purchased power contracts, through the fixed payments in the contract, shift risk back to the utility, its investors, and the customers. The cost of these risks must be netted out of an otherwise valid estimate of avoided costs to arrive at true avoided costs. Otherwise, ratepayers will pay an upwardly-biased estimate of true avoided costs.

When I read that, and without going into a lot of the details in the interior, it sort of triggered a concern for me that the nature of these contracts as such that it may not meet the original objective that was set of balancing the risk and allowing all of the companies to go to the market to finance.

Now I would ask Mr. Peaco or anyone else is this conclusion something that is maybe just abhorrent, it's the opinion of these two people or is this a general concern that maybe has been experienced in the U.S. market?

MR. PEACO: I notice this paper was written in --

DR. SOLLOWS: '97.

MR. PEACO: -- 1997.

DR. SOLLOWS: Yes.

MR. PEACO: But the issue of -- what's today termed as imputed debt is a very current issue in many state jurisdictions with respect to power purchase agreements.

DR. SOLLOWS: Okay.

MR. PEACO: And several of the rating agencies have expressed interest and concern with imputed debt and PPA contracts and used that in their rating of utilities. Several regulatory -- state regulatory commissions in the United States have addressed this issue and debated whether there is a real cost in how to be dealt with it. And I think that there is a -- I think there is a mixed bag as to how it has been treated. Some Commissions have indicated that until there is a real cost, they will defer it to a rate case and others have taken some different stances. So there is a lot of current case history --

DR. SOLLOWS: This is a very much evolving topic then is what you are saying?

MR. PEACO: Yes, it is.

DR. SOLLOWS: And I would infer from that that we might be a little imprudent to assume that the terms and conditions of these PPAs should really be considered cast in stone and that perhaps they could be very much improved upon based on the experience as markets evolve, is that a fair characterization?

MR. PEACO: Could you try that one again?

DR. SOLLOWS: I am inferring from your comment that these PPAs that we are dealing with in this hearing may be -- admit to some improvement by changing their terms and conditions to better balance the risks and take these issues into account, is that a fair extension?

MR. PEACO: You are welcome to go there. I am not --

DR. SOLLOWS: You are not going to --

MR. PEACO: -- I haven't made that assessment at this point.

DR. SOLLOWS: Thank you. The second paper that I have asked the Secretary to circulate is titled "Electricity Company Affiliate Asset Transfer and Self-Build Policies: Renewed Regulatory Challenges." And it is much more recent, November 2004. And I go to page 38 of that paper.

And again I am just jumping to the conclusions here. I guess that says something about me. I read at the bottom of page 38. Wholesale market conditions are leading to a spate of requests that generation assets built/or owned by unregulated affiliates be acquired or contracted out to affiliate utility companies. These proposals call in most cases for decisions that will impact ratepayers for decades to come.

Moreover, there is evidence that some of the transactions may be intended to relive an unregulated affiliate of some currently burdensome debt in the form of underutilized generation facilities. To the extent that the analysis of these proposed transactions is complex and subject to various state and federal regulatory reviews, they may call for a level of independent analytical review that is completely severed from the applicant utility. When I read that, it's -- it puts off alarm bells based -- quite frankly based on the evidence we have in front of us, because we have been proscribed from going into the kind of independent analytical review as you have been. These have been dictated to you and they have been dictated to us. But I see here that the experience in the States, at least according to these two authors, is that this is a serious issue.

Again are these authors perhaps overstating the case or is this an issue that we should be aware or concerned about?

Again Mr. Peaco. I am assuming you are the most familiar on the panel with the situation in the United States.

MR. PEACO: If I understand it right, one of the examples that the article refers to is Arizona, Arizona Public Service Company.

DR. SOLLOWS: Yes.

MR. PEACO: In that situation, maybe just by way of example, the Arizona Public Service Company had created a merchant affiliate back when restructuring was first implemented in California in the late 90s. That affiliate proceeded to build on a merchant basis several power plants in and around Arizona. And then when Arizona abandoned retail competition, they came in in a rate proceeding and asked that those assets be absorbed by the utility at a price and it was a substantial rate proceeding. I think it ended about a year ago where there was a price determined for which they would -- I think there is a similar case in Georgia. I'm not sure if that is in this article. But the issue would be utilities who created merchant affiliates built unregulated investments and then subsequently asked to have them brought back into rate based.

DR. SOLLOWS: And I guess where I am coming from in that is the sense that I have that -- and whether or not it is clear on the record remains to be seen -- is that the export potential from New Brunswick into New England is always cited as a reason for us not having too much capacity. That it is really not too much capacity because we can export it. And I am wondering to what extent the concerns raised in this type of paper are somewhat relevant in that context.

And that export capacity in a sense was a speculative investment on behalf of the generator and therefore may or may not be appropriate to bring into the rate base. So I guess that is where I am coming from in putting this to you.

And if there -- again, I don't expect an answer one way or the other. I just want to make sure that you have an opportunity to address the kinds of concerns that these raise in my mind.

MS. MACFARLANE: Mr. Sollows, could I just say that on the coldest day of the year, NB Power group of companies has an obligation to serve, on the coldest day of the year, every ounce of generation that is owned is required in order to meet load plus reserve requirements.

The reason there is excess available for export is not because we don't need it on the coldest day of the year. It is because we don't -- we have a winter peaking system and we do not need it in the summer months. The system was designed to meet the peak load and to take advantage of export in the non-peak seasons, recognizing that there were economies of scale in doing that so that the peak load is met more economically that building for the base and going out to the market.

DR. SOLLOWS: Thank you and I appreciate that explanation.

But I guess the alternative explanation I have or if not alternative, the flip side of that is the reason you have that excess capacity is because you have a low load factor.

And had you had consistent and reasonable price signals communicated to the market, and undertaken reasonable steps to improve your load factor on the distribution side, you may not have had such excess capacity that you are portraying as an opportunity for exports.

But that is I guess where the fundamental disagreement may occur. But I do thank you and I very much appreciate your indulgence with all of these questions. I don't know who has won the poll but I am done at quarter to 3:00. Thank you very much.

MR. NELSON: Mr. Kennedy, exhibit A-52 is your annual report for 2004/2005.

MR. KENNEDY: Yes.

MR. NELSON: And I am looking at page 28. And I know I am having problems looking at the page numbers myself. It is management's discussion and analysis at the top. And what it has got is expenses.

MR. KENNEDY: Yes.

MR. NELSON: The very last line down at fuel and purchase power for 2004/2005, it has got a total of $497 million.

MR. KENNEDY: Yes.

MR. NELSON: How much of that was in-province? How much of that amount was in-province?

MS. MACFARLANE: That is something that is not disclosed in the annual report for competitive reasons.

MR. KENNEDY: I don't know because that is the first time I have seen that and that is the group of companies, I believe. And I apologize, because I am having trouble reading the numbers.

MS. MACFARLANE: The information isn't there, Mr. Nelson. I am the let's say primary author of the MDNA and we do not disclose the breakdown in fuel costs in-province and out of province. And it is specifically because we do not want to reveal competitive information for our export market competitors.

MR. NELSON: Could I have that filed under 133, Section 133 of the Electricity Act?

MS. MACFARLANE: Yes.

MR. NELSON: I would like to have the break out between in-province and out of province --

MS. MACFARLANE: Yes.

MR. NELSON: -- on that? Thank you.

CHAIRMAN: Commissioner Nelson, just so we are clear, is that the year that report is for which was for not this year, of course, but for last year?

MR. NELSON: 2004/2005.

CHAIRMAN: Okay. Mr. Morrison?

MR. MORRISON: Yes, Mr. Chairman, I do have some redirect but I can assure you it will be very brief.

CHAIRMAN: Fine. Go ahead, sir.

REDIRECT EXAMINATION BY MR. MORRISON

Q.930 - This question is for Mr. Peaco. And I believe it was yesterday, but my mind is not what it used to be. It might have been the day before. It was under questioning by Mr. Gorman. And it appears at pages 4302 to 4303 of the transcript and you don't have to turn it up.

But Mr. Gorman questioned you, and I believe Mr. Hyslop followed up with some questions on the same topic. And he was referring you to exhibit A-5, which I understand was your first audit, Mr. Peaco. Is that correct?

MR. PEACO: That is correct.

Q.931 - And Mr. Gorman put a number of questions to you dealing with whether you had been given access to historical data on heat rates, historical data on hydro production and data and models for load forecast.

And I believe your answer was at that time that you weren't provided this information. Is that fair?

MR. PEACO: Yes.

Q.932 - And I understand, Mr. Peaco, that La Capra did some further work subsequent to A-5, particularly Phase II and III. Is that correct?

MR. PEACO: That is correct.

Q.933 - ANd in the course of conducting Phases II and III, were you in fact provided with that information?

MR. PEACO: Yes, that information was subsequently assembled and I think is actually provided in the confidential data filing.

Q.934 - Thank you. This morning Commissioner LeBlanc-Bird had some questions regarding defining the scope of the work that La Capra did and there may be some misunderstanding as to how that scope of work was defined. And perhaps, Mr. Marois, you can have -- make some comment with respect to that.

MR. MAROIS: Yes, I can. Yes, I guess there has been a lot of discussion in terms of what has been done, an audit, a verification, all that. What is important to Disco is really the terms of reference. Because the terms of reference spell out exactly what we wanted La Capra to do. And those terms of reference were submitted to the PUB for their review and were subsequently approved.

So really at the end of the day from my perspective, it's not as much the title of what was done, but the nature of the actual work that was done. And that is spelled out in detail in the terms of reference and is attached to the La Capra Report.

MR. MORRISON: Thank you, Mr. Marois and Mr. Chairman and Commissioners. Those are all my questions.

CHAIRMAN: Thanks, Mr. Morrison. I want to thank the panel for the attendance here from day 38 to -- I forget. I don't know how many it was but I appreciate it and Ms. MacFarlane, Mr. Kennedy and Mr. Peaco, you are -- you will not be back but the anchor man Mr. Marois will tomorrow morning. So again, thank you very much and safe journey. We will adjourn until 9:15 tomorrow.

(Adjourned)

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

Reporter