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

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CHAIRMAN: Good morning, ladies and gentlemen. If I could, I will have appearances. For the Applicant, Disco?

MR. MORRISON: Good morning, Mr. Chairman, Commissioners. For the Applicant, Disco, Terry Morrison and with me is Neil Larlee and Mac Ketchum.

CHAIRMAN: Thanks, Mr. Morrison. Canadian Manufacturers and Exporters. No Eastern Wind. Enbridge Gas New Brunswick?

MR. MACDOUGALL: David MacDougall for Enbridge Gas New

Brunswick, Mr. Chair.

CHAIRMAN: Thanks, Mr. MacDougall. The Irving Group of Companies? Jolly Farmer isn't here. Rogers, not here. Self-represented individuals? Municipal Utilities?

MR. GORMAN: Good morning, Mr. Chairman. Raymond Gorman appearing for the Municipal Utilities. This morning from Edmundston Energy I have Charles Martin and Michael Couturier. And From Saint John Energy, Dana Young and Jeff Garrett.

CHAIRMAN: Thanks, Mr. Gorman. Vibrant Communities are not here. Public Intervenor?

MR. HYSLOP: Thank you, Mr. Chairman. This morning I have Mr. O'Rourke, Ms. Young, Ms. Power and our witness, Mr. Knecht.

CHAIRMAN: Thanks, Mr. Hyslop. And if there are any Informal Intervenors? There are none. Mr. MacNutt, who is with you today?

MR. MACNUTT: I have with me today, Mr. Chairman, Doug Goss, Senior Advisor, John Lawton, Advisor, Arthur Adelberg, Consultant and John Murphy, Consultant. And when we get to direct examination of Energy Advisers, Mr. Garwood will be joining us on telephone conference system which is wholly integrated with the microphone and loud speaker system.

CHAIRMAN: That was very technical, Mr. MacNutt. Congratulations.

MR. MACNUTT: No, congratulations to NB Power, to Disco.

CHAIRMAN: Thank you, Mr. MacNutt. Any preliminary matters?

MR. MACDOUGALL: Yes, Mr. Chair, one. It's Dave MacDougall for Enbridge. We have one undertaking response to Mr. MacNutt, Mr. Chair. That is available this morning. I have given 11 copies to Ms. Légère and I have given copies to each of the other counsel.

And if we could have that marked as an exhibit?

CHAIRMAN: Sure.

MR. MACDOUGALL: I have a few extra copies if there is anyone else who requires a copy, Mr. Chair.

CHAIRMAN: Good. Thanks, Mr. MacDougall. My records indicate this should be EGNB-3. Any other matters? If not, go ahead, Mr. MacNutt.

CROSS EXAMINATION BY MR. MACNUTT:

Q.381 - Thank you, Mr. Chairman. Good morning, Mr. Chairman, Commissioners and Mr. Knecht.

A. Good morning, Mr. MacNutt.

Q.382 - Would you please turn up your direct evidence, exhibit PI-2 and we will have it open for most of the cross examination. Now at page -- we may run into a little line numbering problem as we did yesterday because we had three different versions of your report. And hopefully the one I have got is on side with the one you have got.

At page 37, note 11, that is the foot note of your direct evidence, you state that "Theoretical economics does not recognize an embedded cost allocation study as the correct basis for defining a subsidy." Is that correct?

A. Yes, sir.

Q.383 - Now turn to page 7, lines 7 to 11 of your direct evidence. Page 7, lines 14 to 16, it is right in mid page. You state that "Costs that are truly fixed and which are incurred on behalf of more than one customer class (known to economists as "joint costs") cannot be allocated on a cost causation basis." Is that correct?

A. Yes, sir.

Q.384 - Now I am trying to determine whether those two statements are related. Is one reason that theoretical economics does not recognize an embedded cost allocation study as the correct basis for defining a subsidy because an embedded cost study attempts to allocate joint costs even though they cannot be allocated on a cost causation basis?

A. I'm sorry, I just missed the beginning part of the question. Could you ask it one more time for me?

Q.385 - Okay. I am trying to determine if the two statements are related so the question is: Is one reason that theoretical economics does not recognize an embedded cost allocation study as the correct basis for defining a subsidy because an embedded cost study attempts to allocate joint costs even though they cannot be allocated on a cost causation basis?

A. Yes, I think I would agree with that.

Q.386 - Now would the fixed costs of a generating plant built to serve more than one customer class be a type of joint costs?

A. Not necessarily.

Q.387 - Could it be?

A. Yes, it could be. The idea of joint costs are costs that are in addition to serving the incremental costs for a particular class. If you think of two classes, a simple situation in which you have two rate classes, and there are some costs to -- each class has some costs to serve. And I tend to think of this as in a picture as a Venn diagram and if I could stand up and draw a picture, it would be easy. But if you picture two intersecting circles, one labelled A and one labelled B, the -- and the total costs for serving A is the whole circle for A and the total costs for serving B is the whole circle for B, the incremental costs to serve load B is the piece of the circle for B that doesn't intersect circle A. And the incremental cost for serving A is the piece of the circle A that doesn't intersect the circle B.

So that the incremental cost to serve either of those loads, which serves as a floor for rates, in an economic sense is the incremental cost. And that is the floor for setting rates.

The piece that is in between are the joint costs and there is no easy way to allocate those costs in a theoretical economic framework.

I could try to draw a little picture of what I tried to describe with my hands and my words.

Q.388 - No, that's fine. Now I am going to ask you to turn up exhibit PI-3. And we are going to go to response to PI EGNB IR-7. Now in view of that response is it your belief that investment and generation is truly -- is a "truly fixed cost"?

A. The investment in generation was not what I was referring to as a truly fixed cost in this piece. Again, if you picture my example of the two circles, there is certain generation costs that you would need to add to again this example.

If you have the stand alone cost of say an industrial -- of the customer class and then you add the residential class, obviously there are some incremental costs to generation that you would need to include in the incremental costs for residential customers and therefore those would not be -- they would not be joint costs. There is some piece of that intersection that relates to the diversity of the loads to the extent there is some diversity between those two rate classes. And that's one of the benefits of having an integrated utility, those benefits of diversity, but those would be contributing to the joint cost piece.

Q.389 - Now I'm going to ask you to -- we are going to eventually go to page 15, line 17 of your evidence. This will lead into that. If the Board determines that the approved methodology for classifying and allocating generation costs is to be modified to reflect the changes in the industry since 1992 --

A. I'm sorry. Hold on a minute, Mr. MacNutt. I either missed your reference or we are not matching up.

Q.390 - I'm not reading from your evidence at this point.

A. Okay. Sorry.

Q.391 - I prefaced this with we are going to get to that reference in a moment but as an introduction to that I am going to ask you to consider the following. If the Board determines that the approved methodology for classifying and allocating generation costs is to be modified to reflect the changes in the industry since 1992 and the restructure of NB Power, do you recommend that the Board adopt a marginal cost approach to allocating generation costs?

A. That's the thrust of my recommendation. I would say we need to start moving in that direction. I believe there needs to be some data collection and analysis that takes place as part of that process, but I would certainly start moving forward in that direction if we want to -- if we do want to reflect the restructuring -- if the Board decides that, yes.

Q.392 - Now in preparing your direct evidence you examined NB Power's hourly marginal generation cost information for 2004/2005, is that correct?

A. I did.

Q.393 - And that's the reference I just gave to you to your evidence. Now I'm going to put to you a hypothetical. Assume one, that the Board adopts a marginal cost based approach for rate design of generation costs.

A. Okay.

Q.394 - Two, that the marginal on peak generation capacity costs for 2004/2005 will be unchanged through 2006. And,

three, those costs are expected to rise precipitously in the following years. That's the premise. Under that hypothetical would you recommend that on-peak rates for 2006 reflect the forecast of marginal costs of 2006 or the expectation of higher marginal capacity costs thereafter?
A. Oh boy. Let me make sure I understand that hypothetical. I have looked at the 2004/2005 marginal costs and -- are we assuming that those stay the same?
Q.395 - Correct.
A. But they are much higher? When you said --
Q.396 - They could rise sharply after 2006.
A. If they rise sharply after 2006. And is there a significant change in the pattern period to period in our hypothetical?
Q.397 - No.
A. So that they exhibit the same pattern in 2000' -- as they did in 2004/2005. So they are simply much higher?
Q.398 - But rising sharply.
A. And I think we are assuming that that's a rise in marginal costs which exceeds the rise in average costs and the marginal costs are then higher than the average costs?
Q.399 - Yes.
A. And there is still plenty of excess capacity in the system?

Q.400 - Not necessarily.

A. Okay. I think one of the reasons -- just to explain why I'm asking all these questions about the hypothetical is that I think that one of the reasons that you observe -- one of the reasons that you observe the relatively flat pattern from period to period in 2004/2005 is that there was plenty of capacity around and the capacity didn't get tight and it was unusual to have to have to be running the combustion turbine plants and thereby observing many hours with high -- with high variable costs.

So that I think that the hypothetical you have structured where fuel prices have risen still assumes that there is a fair amount of excess capacity around. Otherwise, we would need to be -- we would need to be dispatching the combustion turbines. So now I think that I understand the hypothetical, your question -- can you repeat your question?

Q.401 - Under the hypothetical would you recommend that on-peak rates for 2006 reflect the forecast of marginal costs in 2006 for the expectation of higher marginal capacity costs thereafter?

A. Again, I'm troubled by the higher marginal capacity costs thereafter. I think if I were doing the marginal cost analysis and looking at the rate structure that is in place right now, I would -- I would do my best to start reflecting the marginal costs in rates for 2006 as well as I could as a first step. If those marginal costs are -- well I think that's what I would try to do. I would work as much as I could to reflect the marginal costs in 2006. To the extent that needs to reconciled with the revenue requirement then we get onto another level of complexity, and I'm not sure what I would recommend in that hypothetical. It's a complicated hypothetical, I'm sorry to say the absolute answer to this question.

Q.402 - Now wouldn't it be preferable to send customers a price signal in 2006 indicating that increased electric demand will lead a higher cost in later years?

A. I guess I don't think so. If you have set your rates for 2006 that match the marginal costs -- that are consistent with the marginal costs that Disco is incurring in those periods and you have done it in such a way that you recover your overall revenue requirement, I'm not sure I would, you know, make the next leap to say that we are going to start moving towards what we expect the marginal costs to be in the next year until we get there, because now you are setting the price signals before those costs have been incurred.

Q.403 - Thank you.

A. It would be something like doing a -- setting rates for 2005/2006 based on a test year for 2006/2007.
Q.404 - Thank you. Now I would ask you to turn to page 19, lines 15 to 17 of your evidence. At that point in your evidence you state "In fact the traditional approach assigns a lower generation cost to the firm large industrial customers in 2006 than the estimated marginal cost to serve that class in 2005." Do you have that?
A. Yes, sir.
Q.405 - Based on how other costs have increased between 2005 and 2006, how would you expect the marginal costs to increase for the firm large industrial customers?
A. I guess I can't really answer that question. I did not look at all of the other costs in 2004/2005 to be able to answer that question. I only looked at the marginal costs in 2004/2005 because that was what was provided in the interrogatory that we asked.
Q.406 - Now I'm going to ask you to turn to page 15, lines 20 to 22 of your evidence. And at that point you state, "NB Power's marginal cost did not exhibit significant seasonal fluctuations." Do you have that?
A. Yes, sir.
Q.407 - Do you have the work with you -- the work papers on which you base that statement?

A. They are not in front of me, no. I believe we provided them to all of the intervenors when I submitted my -- we provided those to all of the parties who requested them when I submitted my evidence.

Q.408 - Well it may be not necessary to look at them right now. Without disclosing confidential specific marginal cost figures, would you accept, subject to check, that your work papers show a seasonal variation in average marginal costs of eight to 12 percent?

A. Is that average marginal costs after exports or before exports?

Q.409 - That's the reason we have given you a range because --

A. Okay. One is for -- is the eight percent for after exports and the 12 percent -- that's -- I will accept it subject to check. It seems a little higher than what I got, but the thrust of my statement was -- and I -- well I can't really answer that without referring to the graph and it's confidential.

So the thrust of my statement is that I think that the graph shows that there was not a -- there was not a pronounced winter peak for the marginal costs, particularly after exports.

Am I getting you in trouble, Mr. Morrison?

MR. MORRISON: I think, Mr. Chairman, we are fine as long as we don't get into hourly marginal cost data. As long as we keep it at this level, I think we are okay.

MR. MACNUTT: We are moving on.

Q.410 - Now, Mr. Knecht, you testified on direct examination that you might look to two sources of market prices, one, export sales, and, two, the marginal running costs of NB Power Generation. Now would prices for interruptible power reflect marginal running costs?

A. There are a number of ways that we could look at marginal costs. We could look at marginal costs after the firm load has been served which will be the lowest marginal costs that you will experience. We can look at what the interruptible customers pay. And I guess my understanding of that is that Disco then measures the incremental costs for the whole load. It's not really a true marginal cost of the last additional unit. It's the incremental cost for the whole interruptible load. And that would be the next level of marginal or incremental costs that you could look at.

You could look at the marginal costs after the interruptible load is served which would be a little higher still, and then you could look at the marginal costs after the export load is served, and that would be the highest of them all.

Because I was looking for a proxy for market prices which would really be more regional, I would use the highest figure because that's more reflective of what the regional market price would look like.

Q.411 - Now have you reviewed any forecasts of those prices? Excuse me. Have you reviewed any forecasts of those interruptible prices?

A. I suppose I have an average, because the forecast for 2005/2006, which is mostly a forecast test period, is the cost that is reflected in the generation costs for the interruptible load on the system. And again, I think as my understanding is that's an incremental cost for the whole interruptible load rather than a true marginal cost. But to that extent I did look at what that average -- what the average price was for generation costs for interruptible customers.

Q.412 - Now would you agree, subject to check, that the forecast of those prices for 2005/2006 show seasonal variations of over 60 percent?

A. I did not look at it on a hour by hour basis.

Q.413 - No. Seasonal.

A. I did not look at it on a seasonal basis either. I'm sorry. I did not.

Q.414 - I'm going to ask you to turn up exhibit A-12 and go to

PUB IR-76.

CHAIRMAN: The IR number again, Mr. MacNutt?

MR. MACNUTT: Exhibit A-12, PUB IR-76.

A. Yes, sir. I have that.

Q.415 - I will just repeat the question. Would you agree, subject to check, that the forecast of those prices for 2005/2006 shows seasonal variations of over 60 percent?

A. 60 percent from lowest season to highest season?

Q.416 - If you take the winter from November through March and --A. So it's just -- it's winter/non-winter?

Q.417 - Yes.

A. I guess I will take that -- I will accept that, subject to check. I will assume you did those calculations correctly. They are certainly a pronounced -- a reasonably pronounced higher winter average cost particularly on off-peak charges for the incremental cost to serve the interruptible load. I just -- I would caution to make sure that we are not really talking -- I mean a lot of the case on the interruptible load is filling up the low cost capacity, the low marginal cost generation that NB Power has, so that the marginal costs after interruptible load and particularly after export load would likely look very different than this.

Q.418 - Looking at the column for average megawatt hours --

dollars per megawatt hour, how does the January '06 figure compare to the July '05 figure as a ratio?

A. It's certainly more than double.

Q.419 - Thank you. We are going to move on to another item. I'm going to ask you to turn to page 16, lines 4 to 7 of your evidence.

A. Yes, sir. I think I have it.

Q.420 - Yes. You note that "NB Power will often fill up its low marginal cost facilities with export when in-province demand is low." You see that there?

A. Yes, sir.

Q.421 - Do you believe that such exports are possible primarily because the extra capacity is available due to there being low load factor customers on the system?

A. That would be one of the factors contributing to the capacity being available. Certainly having the excess capacity in the system would also contribute to that.

Q.422 - Do you think all export credit should be allocated to low load factor customers as an offset to the high capacity cost those low load factor customers have been assigned by the cost of service study?

A. Well we talked about that a little bit yesterday in I believe my cross examination by Mr. MacDougall. In the study that I put forward, which is essentially the methodology that was approved by the Board in 1992, the export credits are classified as 100 percent demand related and therefore are assigned to each rate class based on each rate class' contribution to peak demand.

And that methodology would assign more of the costs to low load factor customers than another methodology, but it certainly would not assign all of them to those customers.

That's the methodology that I have used because that's the methodology that was approved by the Board.

Q.423 - Thank you. I'm going to ask you to turn to page 4 of your direct evidence, and we are going to look at figure 1Ec-1. Now referring to that figure 1Ec-1 which graphs the history of revenues by major classes for the past 17 years, in the last three lines above the graph you state, "If all other factors were equal this relative increase to the residential class should have eliminated most or all of the residential classes under recovery of costs shown in the cost allocation study filed in the 1992 CARD proceedings." Is that an accurate --

A. Yes, sir.

Q.424 - Thank you. But all things were not equal. Is it not true that the residential class might still have a shortfall of revenues due to increase in unit costs driven by peak capacity requirements?

A. I believe in fact that is a contributing factor, that the load factor for the residential class that Disco is now using is in fact lower than the load factor that was being used in the study in 1988 and 1989, which I think was the basis for the 1991 proceedings.

Two comments about that if I may. First, remember what this graph was. This is just showing a little bit of the history and showing how things have changed and I was in no way trying to argue that all other factors had been equal. I was simply showing that over this period that, you know, the rate increase for the residential class, you know, has been significantly higher than it has been for the other classes.

The second thing I think that I would point out is what I noted further into this evidence is that I have some concerns about the load research for the residential class and think that because there seems to have been a history of under forecasting the load factor that the residential class will actually experience that perhaps we want to make sure that the load factor that we are using in the cost allocation study is accurate by having some better load research data.

Q.425 - Now I am going to ask you to turn to page 9 of your direct evidence at lines 14 to 19. And at that point in your evidence you discuss tradeoffs between capital costs and energy costs for generating plants which seems to be similar -- which seems similar to what Dr. Rosenberg talked about as fuel symmetry. Is that correct?

A. Yes, sir. That is correct.

Q.426 - Now do you agree with Dr. Rosenberg on the allocation of duration related generation costs?

A. Dr. Rosenberg's methodology, which I spoke to, and to be hones, I haven't analyzed all the implications of it to make sure I would be comfortable with it, and therefore, I can't say I either necessarily agree or disagree.

I raised some concerns that I had about the way duration costs were being allocated in his file to cost allocation study, particularly with respect to Coleson Cove in my opening statements. So that I at least identified some things that I think would need to be fixed if in fact we were going to reject the approved methodology and go back and relitigate the whole idea of embedded cost analysis that you know, I understood to have been resolved in 1992. So conceptually, as I said in my opening statement yesterday, I think that I agree with Dr. Rosenberg that we need to try to address this. This would probably -- Dr. Rosenberg's methodology is probably not the one I would recommend if I were starting from scratch.

But as I said, I didn't start from scratch and so you know, I have not prepared and embedded cost allocation study other than the Board approved method.

Q.427 - Now do you accept the concept of duration related costs?

A. I have not seen that done that way in any place that I have worked. But I do conceptually understand what Dr. Rosenberg is driving at.

My approach is a little bit different. In thinking about it, when I think about that fuel for capital tradeoff, rather than taking the duration piece and the fuel cost piece and allocating those separately and going through two different tracks, my reaction would be to look more at the marginal costs in each of those hours and use them and apply the same costs in each hour to each rate class.

Q.428 - Now are there any other areas of Dr. Rosenberg's hypothesis on fuel symmetry that you disagree with other than those you covered in your live direct testimony?

A. I think the concept of the fuel for capital and the capital for fuel symmetry is a generic area that we agree on so.

Q.429 - Thank you. I am now going to ask you to turn to page

14, lines 1 to 12 of your evidence. At that point in your evidence you discuss the advantages and disadvantages of the PPA cost causation approach. Is that correct?

A. Yes, sir. I believe we are going to have a numbering issue here on the line numbers. But the advantages on my copy start on the bottom of page 13 and I believe that the beginning of that response where I start, the primary advantage of this approach, is the statement that I responded to and modified in my response to the interrogatory from the PUB number 1. Just to make that clear before we --

Q.430 - Okay.

A. -- move further along in this line.

Q.431 - Now with that background, would you explain -- excuse me -- would you please explain how, in your view, setting rates based on the PPA charges can get an efficient price signal to customers when the PPAs do not include either time of day or seasonal charges to Disco?

A. I don't believe that the PPAs can provide -- that the billing determinants in the PPAs can provide a reasonable basis for doing cost allocation or for sending price signals to customers.

Q.432 - I am now going to ask you to turn to page 13, lines 7 to 26 of your evidence. And what we are going to look at here is the traditional approach. And over on page 14, beginning with line 13, you discuss the market approximation approach. So those are what we are going to concentrate on those two pages, even though the line numbering may not be exact.

A. Yes, sir.

Q.433 - Now how different would you expect the numerical outcomes to be in terms of costs allocated to each class by using the market approximation as compared to the traditional approach?

A. As a general answer, I cannot really answer that question because the only -- in doing the analysis that I had for market approximation, I was only looking at 2004/2005 marginal costs. And there is certainly a reasonable probability that the 2005/2006 marginal costs would have quite a different pattern -- would quite have a different overall level and quite a different pattern.

So I don't know what -- how those results would compare because I don't have the data to do that analysis.

I looked at the 2004/2005 patterns because that is the information that I had. In looking at those, I determined that using the approved cost allocation method would not be horribly in conflict with those for the current proceedings. But that if we were going to move to market based pricing or market approximation, that we should be looking at those on a forward basis.

Q.434 - Thank you. Now under the market approximation approach, is it likely that the real time price for energy would vary by time of day so that on-peak prices for energy would offset certain demand charges either currently allocated to low load factor customers as a part of the demand charges?

A. I would say there is a reasonable chance that that would happen, yes.

Q.435 - Now going to look at page 55 of your evidence. And I have it as lines 22 to 24. And it is the third bullet under your summation in paragraph 6.

And at that point you suggest that Disco be required to file its first report on load research within three years. Are you suggesting that no progress on this aspect of the CCAS until after the report is filed with the Board?

A. Well I think that is a very good question, Mr. MacNutt. I think that what I was trying to do here was to make sure that we were making definite progress on getting some load research information. Presumably we can get interim information on the load research and use that to begin to try to get a handle on what the allocation on a marginal cost basis would be. And I think that we probably could make some progress before that date.

The more years you have of a consistent load research program, the more confidence you will have in the results. So I think we could make some progress prior to that.

Q.436 - Now in what areas with respect to load research do you believe could be made in less than three years?

A. I would be venturing outside of my area of expertise to comment on that.

Q.437 - How soon do you think we can have some usable results to assist with a cost allocation study?

A. I don't really know.

Q.438 - Now I am going to ask you to turn to page 21 of your evidence, lines 25 to 28. And we are also going to look at page 22, lines 1 to 4.

CHAIRMAN: Give us one bite at a time, Mr. MacNutt.

MR. MACNUTT: Well it just simply continues. Page 21 at the bottom of the page continuing over to page 22.

CHAIRMAN: Good. Thank you.

Q.439 - And it is a comparison of coincident peak demand with contract demand. Are you there?

A. Yes, sir.

Q.440 - Thank you. Please explain the implications resulting from the coincident peak for firm industrial transmission customers being 484 megawatts as compared to the contract demand of 567 megawatts.

A. For very high load factor customer class, you might expect that the coincident peak would be closer to what the contact demand was. And note just for the record here, that it is 567 including the curtailable demand and 529 after the curtailable demand because presumably on a coincident peak there is some chance that the curtailable demand is being curtailed or could be.

And it is just that in looking through the analysis that I did see from Disco, it seemed to me they were using this coincidence factor of .86 to develop the allocator for the large industrial class and that that was based on a historic number. And that's a number that should be reviewed and make sure that it's that it reflects reality and it reflects the current operations.

If in fact that number is incorrect, then as I said, all cost allocation studies you need the right inputs and the calculation of the allocator is a very significant factor that is not methodological. It is simply -- you know, it is simply getting the number right that can have a significant impact on the results.

Q.441 - Thank you. Now going to ask you to look further on page 23 of your evidence. Lines 11 to 29, essentially what you were addressing there is this minimum system, is that correct?

A. Yes, sir.

Q.442 - Now would the use of a minimum system result in the required number of transformers being less than the current number of transformers on the system?

A. No. This is a cost allocation methodology. It doesn't affect actual operations in any way. The object of a cost allocation study is simply to allocate the costs.

Q.443 - Would it assume that fewer transformers in an actual system?

A. My understanding of how a minimum study, if it were applied to transformers -- first off let me step back a minute. Neither Disco nor I have recommended using minimum system for transformers in this proceeding. My understanding of a minimum system analysis for transformers would be that it would simply be one that had the same number of transformers in it, as it would just simply take the lowest number of transformers and multiply it through by all of them, but I didn't go back and check that. So -- and neither Disco nor I have proposed that in this proceeding. So I don't believe it would affect the number but I didn't go and check that methodology.

Q.444 - I'm going to ask you to turn to page 40 of your evidence, and we are going to look at lines 7 to 10, and regardless of the lines we are -- I'm going to where you note that in some jurisdictions interruptible benefits are shared. Do you have that reference?
A. Yes, I think so. Yes.
Q.445 - Thank you. Could you please cite examples of such jurisdictions where interruptible benefits are shared?
A. I don't think as I sit here I would be comfortable venturing -- making a specific citation on that. I would have to go back and look. This statement is based on my experience that now stretches back a few years. To say anything -- to pick a specific example that's current right now would be difficult.
Typically the sharing of the interruptible benefits is either, you know, explicit or reflects itself in a revenue cost ratio for interruptible customers that exceeds 1. But I don't think I can give you a specific example as I sit here.
Q.446 - What is the mechanism by which they are in fact shared?
A. Well that was -- I think I just answered that question. There is a lot of ways. It just shows up as a higher revenue cost ratio for that class or it's simply

the rates are set above the allocated. When the rates for the interruptible class are set above the costs for the interruptible class, they are therefore providing a cross-subsidy in the terms that I have used in my evidence to the other rate classes, and therefore they are sharing those benefits.

Q.447 - Thank you. Yes. There is no particular page to turn up on this. I would just like to discuss with you something I discussed with Dr. Rosenberg during my cross examination of him on Thursday, October 27th. The question related to generation maintenance. Do you recall that exchange?

A. Yes, I believe I do.

Q.448 - Now first I would like to deal with the concept of a stand alone generation utility serving only high load factor customers.

A. Yes, sir.

Q.449 - Beyond having generation capacity sufficient to cover a 20 percent reserve margin, such a stand alone generating utility would require additional generation in order to perform periodic maintenance on its generation units, would you not agree?

A. I'm not sure that I would. And again it becomes a technical issue about what sort of base load generation you are talking about and it would depend on the overall size because you get into it in economies of scale issue. But if you have a very large high load factor load, three or 4,000 megawatts, okay, you can then have ten plants, ten units, serving that load, and if they can all run at a 90 percent capacity factor and need to be down for ten percent of the year, the CTs that you build for your reserve margin will obviously have to run when each individual unit goes down and you will be running at a fair amount of the time, so that you will be having to provide some level of the load from the CTs, but you may not need to build base load capacity in excess, and you may not want to build base load capacity in excess of what you need.

Q.450 - And in what you were just saying, CT refers to a combustion turbine?

A. Combustion turbine, yes. And depending on the maintenance requirements and how long it would need to be down, you might build something other than CTs to provide the additional capacity for maintenance. I think the answer depends on what the numbers are in this -- in the -- for how long the plant really needs to be down for maintenance.

Q.451 - Thank you. Now please turn up the response to PUB

IR-110. That's exhibit A-17, PUB IR-110. A-17, PUB IR-110.
Now I want you to refer to figure 1 forming a part of that response and that figure is entitled "2005/2006 Available Capacity versus Disco and Firm Export Load." That figure shows a dark shaded area which represents a capacity that is unavailable due to plant outages and D rates, would you agree?
A. That appears to be correct.
Q.452 - How does your proposed methodology provide assurance that there is a fair allocation of costs to the high load factor customers for the use of generation required during the time of planned maintenance on the generation plants normally serving their load during the winter period?
A. Well the methodology I proposed is simply the Equivalent Peaker methodology and therefore the -- which is the one that the Board has approved, and therefore the high load factor customers are certainly paying for all of the capacity except for that piece that is really related to the individual system peak.
I think what I would add is that if you move to a marginal cost based system, when a plant is down for maintenance and if it's a base load plant that is down for maintenance and if it's down for maintenance in the spring, if you take your coal plant for maintenance in the

spring and you now have to dispatch higher cost generating capacity, that will then be reflected in the marginal cost in the spring, and if you are allocating those costs on a marginal cost basis the customer's contribution to those hours in the spring will reflect the fact that the coal plant is down for maintenance and the marginal costs are higher.

Certainly in the spring -- the off-peak season is the spring and the summer and the fall -- the large -- the high load factor customers are a greater percentage of the load and therefore won't get assigned those higher marginal costs because the higher cost plant has been dispatched in that period.

So I think either way under the recommendation that I have, the fact that units are down for maintenance will be reflected in the cost signal -- the costs that are assigned to the high load factor classes.

Q.453 - Now when you say either way, do you also mean under the embedded cost approach?

A. Under the existing Equivalent Peaker Method I think because such a large percentage of the costs get allocated on an energy basis, that the high load factor customers are bearing their share of the fact that the generating -- the base load generation plants may be down for maintenance in this period.

I don't want to argue the numbers here, but sometimes, you know, the amount of time that a plant is down for maintenance, it's down because the company knows it doesn't necessarily need that unit in that period, so it can take it's time if it has plenty of capacity. And these numbers might change depending on what the -- for the period that it actually is required to be down for maintenance.

MR. MACNUTT: Thank you. No further questioning of this witness, Mr. Chairman.

CHAIRMAN: Mr. MacNutt, you told me an hour-and-a-half. You have broken from your previous --

MR. MACNUTT: The witness was very responsive.

CHAIRMAN: Yes. Normally I just double what you say. Now I have got to take 33 percent off. We will take our 15 minute break.

(Recess)

CHAIRMAN: Before your redirect, Mr. Hyslop, the Commissioners have a few questions.

<u>BY THE BOARD</u>:

MR. BELL: Good morning, Mr. Knecht.

A. Good morning, sir.

MR. BELL: If I could just direct you for a minute to page

56 of your evidence, in lines 14 to 16 --

A. Hold on for a minute. I don't have 56, so -- go ahead. If you quote it I will find it.

MR. BELL: All right. It's with regard -- you concur with Disco's goal to phase out the residential declining block rate and you say that this goal can and should be accomplished much more quickly and significantly more progress can be effected in the proceeding.

I have two questions on this comment. The first is what do you mean specifically by more progress can be -- significantly more progress can be made in this hearing, or in this proceeding?

A. At the time that I wrote that, sir, I was anticipating that this evidence would be used to set rates for 2005/2006, and that therefore there would be another adjustment in rates for 2005/2006 --

MR. BELL: I see.

A. -- that would reflect the results of this proceeding. As I understand it now, that's not the case and therefore this could only be reflected in the 2006/2007 year. Nevertheless I think what you can do in this proceeding is, as I mentioned in my opening statement, set some guidelines -- provide some guidance to Disco about what level -- what the maximum level of increase is for the electric heat customers that would allow them to make -- to continue to make significant progress with each rate increase, and by setting those guidelines it will force the process a little bit more than we have experienced in the past.

MR. BELL: And in setting those guidelines we should be sensitive -- do you believe we should be sensitive to the perhaps higher than average increase that the residential heat class would be looking at for the current proposed year?

A. Yes, sir. That's the most common -- one of the most common things that boards will consider when evaluating -- we know where we want to go. How fast should we get there? We need to set some guidelines for what the maximum increase is.

There are rules of thumb, one-and-a-half times the average increase for the class, two times the average increase for the class, that kind of general guidelines -- guidance for the applicant.

Again, as I mentioned yesterday, the other thing I would say is if there are farms -- if there are, you know, a relatively small number of farms that consume a lot of power, don't let that affect your -- don't let that fact drive the bus. Make it combinations for that group if you need to. But for the vast majority of the residential customers, try to move the tariffs in line with where we want to go as quickly as possible, subject to the maximum increase that any one class would get.

MR. BELL: Okay. Thank you very much.

DR. SOLLOWS: Thank you, Mr. Chairman. Mr. Knecht, I have a few questions arising out of what I heard today and some others that I want to go back with over your testimony in some other material that we have seen.

There has been a lot of discussion about the use of combustion turbines as a peaking capacity plant and the costs of using those as representing the costs for the system. What is a typical capacity factor for a CT plant used for peaking service for an electric utility?

A. I'm not sure I could answer that with a lot of confidence, but my sense is five to ten percent.

DR. SOLLOWS: So if -- my recollection of looking back through NB Power's annual reports is we are looking at capacity factors under one percent. Is that likely to be an efficient utilization of that kind of hardware?

A. That's certainly what you would expect to see in a utility that has a very high reserve margin right now with a lot of excess capacity there. But it suggests that what you have has more capacity sitting there at present than what you ideally need.

DR. SOLLOWS: Right.

A. Capacity of course comes in lumpy increments.

DR. SOLLOWS: Okay.

A. So that can contribute to the problem.

DR. SOLLOWS: So it's really just a reflection of perhaps excess capacity on the system.

A. Yes, I would say so.

DR. SOLLOWS: Okay. So related to that it's my understanding that when required reserve margins are calculated for system integrity reasons, they -- you have to take a fraction of the attached load or the maximum unit size.

So it would seem to me that there is -- for the unit that's the largest on the system, if that's greater than say 15 or 20 percent of the system load as it historically has been in this province, there would be a reserve margin cost that is attributable to that plant, and therefore should be reasonably costed in with that plant so that it gets distributed to the customers that are benefiting from the use of that plant.

Is that the way the cost allocation is done, or is it just sort of socialized across all of the customers?

A. I don't recall seeing a study that addresses that particular issue, that is, having excess capacity because you have a large unit contributing to a large reserve margin. I believe that the Equivalent Peaker Methodology or a capital substitution method, either adjusted or unadjusted, is implicitly recognizing that in the allocation method -- I think I need to actually think about it a lot more to sort it out entirely, but I believe in either an Adjusted Equivalent Peaker or a method that uses the cost of a combustion turbine plus some variable fuel -- some variable energy cost from period to period -- will implicitly reflect --

DR. SOLLOWS: We are not certain how it's handled in the evidence before us or are we?

A. I'm not sure I could answer it with confidence. I might have to go back and take an undertaking on that if you like, but --

DR. SOLLOWS: Perhaps there will be enough -- that's okay. Thank you very much. Now I'm trying to recall. Did you participate in the capacity planning hearing in the early 1990s? I know you were involved in rate cases, but were you involved in the capacity planning hearing?

A. I believe -- my recollection is I sat next to Mr. McKelvey in the integrated resource planning --

DR. SOLLOWS: Okay.

A. -- generic proceedings.

DR. SOLLOWS: I think I was a couple of tables behind you then.

A. I have to get -- that's very possible. I have to say my recollection of what we did in that proceeding is pretty limited at this point.

DR. SOLLOWS: Okay. I just want to come to a point here that we have talked about at different times and I think in particular this notion of scheduling outages at different times of the year. I have in front of me -- I don't know whether you recall -- back at that time NB Power prepared annual load and resources reviews that provided the summary information about what was available in each month of the year both for power and energy. Do you recall that kind of evidence?

A. Not very well.

DR. SOLLOWS: I guess where -- would you be surprised to -- with the notion that in the spring months of the year there is an awful lot of -- or a significant amount of extra hydro capacity available?

A. Yes, sir.

DR. SOLLOWS: You are surprised with that?

A. No, that doesn't surprise me at all. My sense is actually the hydro is probably running quite well about

now too.
DR. SOLLOWS: It may indeed be well above average.
A. A nice thing, with fuel prices being what they are.
DR. SOLLOWS: And so that would likely have an impact on the cost of an outage that's scheduled in the spring, would it not?
A. Yes, sir. I think to the extent you get that extra capacity from hydro that's a logical time to do the maintenance on your other low variable cost capacity.
DR. SOLLOWS: The other piece of information from that -- or one of those reviews is that there is some seasonal energy storage available on NB Power's system, is that consistent with your recollection?
A. Pump storage? Seasonal --
DR. SOLLOWS: Well no. Seasonal just run up in the reservoirs through the summer and fall months for use during the winter.
A. My -- there was Disco's response which indicated that most of the capacity was essentially runner river. I guess my understanding is that Mactaquac has some -- has a head pond behind it that might be used for some of that, but I don't know how much you could shift from -- on a seasonal basis.
DR. SOLLOWS: Yes. I think their evidence at that time was

something around 74 gigawatt hours which is certainly less than ten percent -- more like five percent of their total hydro energy.

A. So it's relatively --

DR. SOLLOWS: That wouldn't have any impact on the cost allocation or cost analysis that we have been dealing with in this hearing, would it?

A. I think it might affect Dr. Rosenberg's methodology, that he would need to -- to the extent there was some -- the way hydro is operated -- it might affect that if there were -- if hydro was essentially being used as more of an on-peak resource, that that might affect -- again I think you would have to ask Dr. Rosenberg, but my sense is that if in fact you had a significant seasonal storage, which is a big factor, not just on peak/off peak, but seasonal -- his methodology might need to reflect that.

DR. SOLLOWS: Thank you. I would like to move on now to deal with the topic that appears on PI-2 which is your exhibit, and pages 29 to 31.

Now, when I reviewed these pages of your evidence, you noted some issues related to the zero intercept cost of transformers and that's used to compute the fraction assigned to customer category?

A. Yes.

DR. SOLLOWS: Right. Are you concerned that the method that Disco used to find the zero intercept cost of $780, are you concerned with that result?

A. I did express some concerns with respect to that methodology in that it wasn't so much the $780 number that I was concerned about, particularly here on the bottom of page 29.

What happened was they weren't applying that $780 to the transformers that they had excluded from their regression analysis. They were assuming that those larger transformers also had the same percentage customer component as the smaller ones. Whereas if you were doing the analysis correctly, you would apply the 780 only to -- you would apply the 780 only to -- you would apply that $780 to all of the transformers.

The second thing that I got into in looking at the zero intercept analysis that they had prepared was that they arbitrarily exclude data from the regression analysis for reasons maybe that it makes sense to exclude it or maybe not.

When I do a zero intercept analysis, I do it in a slight different functional form than what Disco used. And when I run it that way, I get somewhat different numbers, but I can use all of the data without excluding the large transformers.

In essence, I do a different weighting scheme for the data points in the regression analysis that I do. And I also did the analysis at a little more detailed level than Disco did, because they provided me some additional data in response. And I did it with some data that they described as regional data to calculate a customer component that way and then I used all of those things to come up with an overall recommendation for what the customer component would be.

When I ran the regression on the regional data, it implied a noticeably lower customer component than running it only on NB -- on Disco's data and Disco had indicated that it relied on both of those regressions in setting its customer component.

DR. SOLLOWS: I see.

A. Sorry for the long answer.

DR. SOLLOWS: No, no. That's fine. I guess I -- the reason I am asking is when I reviewed it I guess I had some of the same concerns that you noted in terms of the exclusion of data.

And so after I had had a chance to hear what the intention was in our hearing in Saint John, I took I guess what might be a simple minded approach and simply took the costs in each transformer size class and did a multiple linear regression to determine the unit cost and the kilovolt amp cost.

What is wrong with that approach?

A. I hope it is not a simple minded approach because that is what I did.

DR. SOLLOWS: Okay. Well I might have destroyed your credibility before this panel. Sorry. So if that's what you did --

A. I will explain it in a little more detail but because you asked -- when I read in the transcript, I read your questions to Dr. Rosenberg and you actually cited numbers that were on the order of $750 per transformer and $14 per kva. And I went and looked at my work papers and I have virtually the same numbers.

When I ran it on the full data set -- and I assume when you use total demand you basically took number of transformers times the demand for each transformer?

DR. SOLLOWS: Yes.

A. Yes, that is essentially what I did. I actually technically ran it without a constant so that it would be the same -- essentially the same equation as the standard zero intercept approach.

DR. SOLLOWS: Well I eliminated the constant because it wasn't significant statistically.

A. Then --

DR. SOLLOWS: And for the record, I tested product and quotient terms to make sure that they weren't significant.

A. You actually went further than I did, I have to say, although I tested it a number of different ways. I used a more detailed analysis. But yes, we did the same analysis.

DR. SOLLOWS: So a $751 per transformer based on NB Power's data would seem to be a reasonable number to use?

A. Well again, I don't actually because I went and I used the regression analysis for the regional data. And if you go and you run there, you end up with a number that is more like $500 a transformer as the customer component. So I considered both of those.

I haven't checked to see what the customer component implies but I assume it will be somewhere between $500 and 750. Again, those numbers are adjusted for inflation so you need to -- I mean, you are essentially deriving a customer component there and then you apply that back to the -- to the --

DR. SOLLOWS: What would be the possible reason for the -- I think you are describing this as a significant deviation between the regional data and NB Power's data? Is the regional data perhaps more urban?

A. I don't know. I would be speculating at this point. They indicated that they relied on it -- they didn't provide much of a background for me to understand what that was. And I didn't -- I did not chase it any further than that. But different systems vary. And the costs vary. And even if you can -- remember, there is a certain amount of uncertainty in all of this so while we are getting different numbers and they seem like they are significant differences, they don't surprise me.

DR. SOLLOWS: Okay.

A. To be of that magnitude.

DR. SOLLOWS: It's typical.

A. That's why I would use them all rather than only using one of them. To the extent possible use different reasonable sources to get different numbers and then use an average of them all.

DR. SOLLOWS: Okay. When I -- carrying on with the analysis, when I went and looked at the residuals on each class, I found two classes that had fairly high residuals, about $6,000,000 excess costs over the model costs. And it struck me as fairly large. They were 38 and 25 percent of the class costs.

That made me wonder if one reason for the discrepancy might be that there are a larger fraction of polyphase transformers in those classes. Do you know if anywhere in the evidence is there an indication of what fraction of the transformers in each class are multiphased?

A. I certainly don't know.

DR. SOLLOWS: Okay. Well -- so if we don't know I guess where I am going with this, if we don't know it's in the evidence and -- but if we assume that Disco could provide it, would it perhaps make sense to use instead of the actual number of transformers the number of single phase equivalent transformers, just to sort of take that error out?

A. Statistically you could do it that way. My reaction off the top of my head without having thought it through carefully would be to put in a dummy variable for those --

DR. SOLLOWS: Okay.

A. -- and do it that way.

DR. SOLLOWS: Okay. Thank you. So I think I understand where the dollar per transformer cost comes from and I think Mr. MacNutt addressed this next issue as well, but I'm still having a great deal of difficulty with the number of transformers that would be required for service. And I guess what is giving me this difficulty is I wander -- I can walk through my community in the evening, I see many poles with three transformers on them, and it seems to me that in a minimum service sense where you have got only single phase power provision or energy provision, you wouldn't need three transformers at the top of a pole, you would need only one.

And so I'm having a hard time coming to grips with the rationale for taking that 750 or 520 or whatever it is and multiplying it by the total number of transformers. And first I would like you to sort of comment on the rationale for it and then I would like to sort of outline to you the approach I took to try and see what a reasonable number should be and see if it's -- if I'm going too far off in one direction or another.

A. The -- let me -- in responding let me step back a little bit about the zero intercept methodology and in fact the overall classification of distribution system costs.

We know there is a demand component. We can see it. You put in bigger transformers and they can carry more demand. Larger conductors can carry more demand. And so the higher the demand, the higher the cost for those items. And we can estimate those costs by using a regression analysis based on the size of the equipment and the increase in costs. So that we know that, you know, if you increase the carrying capacity of a conductor by a factor of two, we look at the slope of the line in your zero intercept analysis and that's the demand component.

We then have something left over, okay, and that piece is the intercept piece in the linear equation. And we are assuming that that number is customer related, okay.

There is no -- you know, there is no proof that that is related to the number of customers.

We are really not even multiplying it through by the number of customers. In may ways what the zero intercept methodology is doing is measuring the demand component, and that's the slope. It's then measuring a piece that is the residual, okay, which will be the intercept times the number of transformers, but it's simply the residual.

Now we use that as a proxy for the customer component because we feel like there is a customer component. We believe there is a customer component associated with distribution costs. But there is no way to prove that that intercept is a customer component. It could simply be economies of scale. It doesn't necessarily vary with the number of customers. There is probably a combination of factors.

So that when I answer -- I guess the answer to your question is that we are applying a methodology where we figured out what the demand component is, we believe the residual is a customer component because it makes common sense to us that more smaller customers are going to require you to put in more poles and longer conductors than one -- you know, one larger distribution service customer.

So that's the theoretic underpinnings for it, and then to try to push much further than that we start to get into a lot of problems by, you know, making sure we are counting all of the transformers or the feed of conductors.

And I think that when we come to it for the analysts who advocate the basic customer method, what Mr. Adelberg and Garwood call the basic customer method or what I call the 100 percent demand method, is they say, we don't know what those costs are. There is no proof that they are related to the number of customers. You can't demonstrate using any of the analysis that you have done that those costs will increase with the number of customers. Therefore we might as well call them all demand related.

DR. SOLLOWS: So it could be anywhere from zero percent customer to 100 percent -- or to 50 or 60 percent customer and justify anything in between by judgment.

A. That I actually think is a fairly accurate assessment of the range of possibilities that you see in Board decisions with respect to the classification of distribution costs.

DR. SOLLOWS: Okay.

A. I mean, to be honest my sense is in Canada more often I will see zero intercept or minimum system than in the United States where you will see more -- you know, somewhat more reliance on the 100 percent demand methods.

DR. SOLLOWS: Okay.

A. Certainly more advocates pushing for 100 percent demand methods in the United States.

DR. SOLLOWS: All right. So I guess what I would like you to do at this stage then, if you could sort of listen to sort of the way I approach this notion of figuring out -- I'm still comfortable with the approach of unit cost per transformer, but rather than be, you know, something like throwing a dart between zero and 54 percent -- I'm an engineer, so I like to play with numbers, and I would like you to if you don't mind critique the approach that I have taken if I outline it. Would that be okay?

A. If I can. I will do my best.

DR. SOLLOWS: The way I approach it is I asked myself

what's a minimum level of service and I looked through the evidence and I said well to not be hung up on this for too long, I will say 6,000 kilowatt hours per year at a defined load factor and a defined power factor, I used 30 percent load factor and 90 percent power factor.
And from that I calculated an average demand of about a little more than 2 and a half kva for what I am calling a minimum service customer.
A. Not a zero service customer, but a --
DR. SOLLOWS: No, a minimum.
A. -- minimum -- coming from a minimum system perspective.
DR. SOLLOWS: Right. Then I took an estimate of about 330,000 customers for Disco and multiplied the numbers and got the total number for minimum service demand which is about 837,000 kva.
Now looking at the data that we had and that we did the regression for, when you took the total number of transformers they have and the total number of kva that those transformers represent, you find an average transformer size of about 41 kva, just dividing the two numbers.
A. I guess I am going to -- can I stop you there for a minute?

DR. SOLLOWS: Sure.

A. My sense is that there are a number of customers who take service at primary voltage on a distribution system.

DR. SOLLOWS: Okay.

A. And that they would not be using those transformers. Those transformers get assigned only to -- because the transformers are -- these are transformers that step down from --

DR. SOLLOWS: So this would be --

A. -- primary to secondary voltage.

DR. SOLLOWS: So the number of 330,000 is probably too high?

A. Yes, but I would have to go look at the -- I would --

DR. SOLLOWS: So is 300,000 --

A. -- that is the total number of customers I think that you -- for looking -- I believe that Disco's only assigning those transformers to secondary voltage distribution customers.

DR. SOLLOWS: So that is probably too high. So I could go back --

A. But let's work through it methodologically.

DR. SOLLOWS: Yes. Then I took the average transformer size and divided it into the total minimum service demand to calculate a number of about 20,500 transformers to meet minimum service requirements. And that results in a 10 percent allocation to customer and 90 percent to demand.

I guess at this stage what are your thoughts on a) the process and b) the outcome? And if I am totally out to lunch, you should feel free to say so.

A. You may have to run it -- you have 2 and a half kva per customer for a minimum size customer, 330,000 customers, 830,000 kva. I missed the next step.

DR. SOLLOWS: 41 kva for an average transformer. I simply took the total number of kva in the transformers they had, divided by the total number of transformers, to give me an average size of transformer. And used that average --

A. Okay. You figured 41 kva --

DR. SOLLOWS: Into 837,000, giving me 20,500 transformers.

A. And then you compared that to --

DR. SOLLOWS: When I take that number and multiply it by my $751, I got about 15.8 million which is about 10 percent of the allocation.

A. All right. To be honest, sir, to answer this question, I would really much prefer to take an undertaking rather than --

DR. SOLLOWS: Okay.

A. -- and I will --

DR. SOLLOWS: Would you?

A. -- I will be happy to go back and think about this little problem rather than try to -- I have not --

DR. SOLLOWS: I understand.

A. -- before. And, you know, as I said, conceptually the zero intercept kind of comes from a different direction. But if I -- if I may --

DR. SOLLOWS: I would be more than happy to have you do that. But if you don't mind, I would like to continue on because I didn't stop there.

A. Okay.

DR. SOLLOWS: Well it's just --

CHAIRMAN: Mr. Knecht, you are assisting releasing a dragon here. And what I am going to suggest is that I have asked Dr. Sollows if he would put this down in example question form and submit it to all parties including Disco, and they can file their written comments in reference to same.

DR. SOLLOWS: Can I go on?

CHAIRMAN: Go on to the next question.

MR. MACNUTT: Just for point of clarification, does that supersede the undertaking?

CHAIRMAN: Yes. I think it would be appropriate the same question is put to everybody and they can respond to it.

MR. MACNUTT: Okay. I just wanted that --

CHAIRMAN: Thank you, Mr. MacNutt. Go ahead, Mr. Sollows.

MR. HYSLOP: Mr. Chair, we did give an undertaking a moment ago with regard to the hypothetical. Would I be correct in assuming that once this written question goes out, that undertaking will be answered as part of answering your hypothetical, Dr. Sollows?

CHAIRMAN: Yes, I believe that that's precisely what Mr. MacNutt just asked and that certainly would be I think appropriate. Okay. Go ahead.

DR. SOLLOWS: Thank you, Mr. Chair. So I want to at this stage then change topics completely to talk about issues relating to -- generic issued relating to rate design. And one of the things that I have discovered from my background reading on this is that there seems to be some debate still over the applicability of time of use rates in -- for distribution customers in comparison with what have been termed Hopkinson rates or demand energy rates with a demand reservation component.

Are you familiar with that sort of discussion that carries on in the written literature?

A. I'm not sure that I follow the literature in great detail but I observe that different utilities have different tariff structures.

Are we focusing primarily on small low load factor customers, residential and small commercial or in general?

DR. SOLLOWS: On customers typically connected to a distribution grid rather than transmission.

A. Okay.

DR. SOLLOWS: And I have got the sense from reading my readings that we talked yesterday -- or we heard yesterday about second best and second best optimality and that sort of thing. There is an argument that I have seen that the -- rate structure that includes a demand reservation component and charges for both demand and energy can be sort of a reasonable second best alternative to full interval metering and interval time rates designs.

Is that consistent with your understanding?

A. Well I think -- yes, it is. That a -- imposing a demand charge or imposing a block structure where it is appropriate is a better way of reflecting cost causation than simply having a flat energy charge.

I'm not sure that there is any real -- that there is any real debate about that. For you know, classes where it is cost effective and you know, hourly price signals or seasonal price signals or on-peak, off-peak, you know, price signals are imposed in the tariff, I think those are probably a little more accurate than a straight demand charge because it is reflecting the time of use cost signals that the distribution utility is incurring.

DR. SOLLOWS: As I --

A. But absent that -- and also, just stepping back, remember, in many places we are now getting unbundled rates. So you start thinking about -- you may start thinking about generation rates differently than you think about distribution rates.

Distribution rates, because the costs are primarily demand and customer related, obviously to the extent you can use a demand charge, it is going to more accurately reflect the cost causation and the cost allocation study than using an energy charge or block energy charge or anything like that.

When you get to generation rates, I think then because we see hourly prices and we see seasonal prices, that the extent you can impose those on a time of use basis, that might be the direction you want to head in the long run.

To bring it back to the specific case of Disco, and at this point I am looking at the residential rate, and given where we are, I think the most progress you ought to make now is try to deal with the declining block rate, which is, you know, if anything, backwards.

That it should either be -- you know, it should either be flat, or having an inclining block rate. But that at this stage, phasing out the declining block rate structure is the thing -- is the thing to focus on and then move on to thinking about seasonality or time of use rates.

DR. SOLLOWS: Okay. I guess where my thoughts lead when we talk about particularly the residential rate structure, but I think it would apply commercial or anyone connected to distribution is this notion of a reservation charge, to me that is awfully similar to a -- sort of a service charge that might scale with the size of the service entrance for a customer.

So that a customer served by a 60 amp entrance might pay one service charge. A customer served by a 200 amp entrance would pay a different service charge. And those differential service charges would reflect their potential demand on the system as opposed to energy.

Is there any precedent for thinking of things in those terms?

A. Not that I -- not that I have seen. Conceptually what you are saying is I think consistent with what a demand charge does. But the advantage of a demand charge is you really are only charging an individual customer for what its peak demand is.

DR. SOLLOWS: Right.

A. And you know, obviously for larger customers, they are going to size all the equipment, large industrial customers, they are going to size the equipment they need to meet expected demand and therefore, it would be similar because the equipment will be sized for that purpose. However, if you have got two residences that have the same, you know, amp service, but one of them has double the demand of the other, I don't think -- and that simply the standard service, there is a lot of economies for the utility in making everything the same from residential customer to residential customer, that it would -- that it would be equitable, or even appropriate, I think, to assign two residences the same charge if they have the same amp service but have very different demand levels. Because remember, the demand is going to affect the system that is most local to those customers. But as you get into transmission costs and back all the way up to generation costs that might have a demand component, you have moved way back into the system and the individual demands of those customers will have a -- are much more relevant than the size of the service -- the capacity of the service that is there.

DR. SOLLOWS: So to the extent that you implemented this, you would want to be very sure that customers with a large service, but nonetheless a very small demand, had an opportunity to have that demand measured and be billed on that actual basis?

A. Yes, I think. In effect, I think that is why there is a difference between the demand charge and the customer charge.

DR. SOLLOWS: Right.

A. The customer charge for a residential customer is going to reflect the meter. Regardless of the size of the demand of that customer, the meter needs to be there and the meters are generally the same from residential customer to customer.

Service jobs the same thing, the service line coming down from the distribution system. And those are recovered in the customer charge. So when I see what -- and in fact, from class to class you see different customer charges reflecting the fact that as you move up in the size of the distribution customer classes, the customer charge goes up and the customer costs goes up reflecting the higher costs of the meters and the services to serve those customers.

DR. SOLLOWS: Okay, thank you. Now there is one last issue I wanted your thoughts on. And it relates to the notion of the cost of customer service interruptions. Are you familiar at all with the work that has been done to estimate the value or the cost of customer service interruptions to various classes of customers, residential, commercial, industrial?

A. I have not participated in any of those studies.

DR. SOLLOWS: You haven't reviewed them or --

A. Not recently.

DR. SOLLOWS: Okay. I guess I will just have to leave that there. Thank you.

CHAIRMAN: Mr. Knecht, I this morning went back and looked at the transcript when Mr. Larlee was on the stand concerning the proposed installation of 200 meters in reference to the residential class.

And I do have, Mr. Morrison, a -- I picked up a couple of excerpts from the 28th of September, one at page -- it's question -- it starts around question 808 and then again around 823 I guess or thereabouts. I believe that's -- on the copy I have the pages are I think marked at 1092 or thereabouts.

And what I was specifically looking for was Mr. Larlee came back after that, as I recollect it, and described in particular the way in which the sample is taken. Perhaps if Mr. Larlee can assist me in setting this up so that the witness will know accurately how you are planning on doing that, if he could check the transcript. I have got a couple of other questions.

Mr. Knecht, in your -- I believe it was your direct yesterday, but I stand to be corrected there, you were talking about the distribution costs and you were making some suggestions as to how to change the declining block rate. You talked about churches and farms were included in that customer class and therefore it would distort the rest of that class because of their particular consumption patterns. That's certainly what I took.

A. That was my understanding. I don't -- I haven't looked at the data to understand what the implications of those are, but in discussing the matter, that's my understanding, and in looking at the tariff design is that there are churches and farms are served under -- are served under that tariff and might have very large loads.

CHAIRMAN: How would you take those out, as I recollect you saying, and perhaps put them in a separate class by themselves, et cetera.

How would you differentiate between the normal residential electric heat and non-electric heat and that grouping of churches and farms if you were to separate them, or try and do so.

A. Certainly for churches you simply specify it in the tariff. I mean if it's a church you just say it's eligible for -- it would be eligible for a rate that would apply to churches. I have seen churches and schools sometimes as a separate rate category.

And I think the simplest thing would be you could simply write it as a church or a school that has an annual load above some level, so that you would be pulling out the customers who would be most affected by eliminating the declining block tariff, which is the largest customers, and say -- say every church or farm that has a load in excess of 50,000 -- pick a number -- pick a very large number -- 50,000 kilowatt hours a year or something like that -- would be eligible for the service.

Certainly that imposes, you know, a verification of responsibility on the distribution utility, but if you describe it as a church or a farm in the tariff I think it would work.

CHAIRMAN: Then you would have to presumably in the --

A. Above a certain kilowatt hour level.

CHAIRMAN: Yes.

A. And you want to set it fairly high because those are the customers you want to provide protection to.

CHAIRMAN: Okay. Now I have heard a number of proposals on how the declining block rate would be done away with in New Brunswick.

One of my concerns has been when listening to it I think we have to -- I think as a public policy issue we have to information out to the consumers of electricity in the province if the Board in fact says, yes, we agree with what has been said in this hearing room, that that declining Block rate will disappear, and there are a number of ways it's been suggested to do it.

My question is I know there are definitional difficulties in doing this, but I would just like your comments on what if the Board were to say effective four months from this date no further customers will be -- new customers, and again that's where the definitional problem comes in -- will be granted the declining rate.

A. In essence you are suggesting that a possible approach might be to grandfather existing customers into the declining block rate and then apply different rates for new customers who come on.

CHAIRMAN: Well grandfather with a termination date set.

A. With a termination date, yes.

CHAIRMAN: Yes.

A. I can't say I have seen it done for the residential class, although you certainly see it done in a number of general service tariffs, and in fact Disco is doing it with the GS II class by not allowing anybody else in. In essence you are setting another classes rates.

I suspect -- and the Disco witnesses might know better, but I suspect that that might be administratively difficult. Particularly when people change residences, is that a new customer coming on? You would need to deal with those kind of transitions and are you sending a weird circle about customers who move. I think it might pose administration difficulties that I think you would need to look at before you would adopt that kind of approach.

I think to be honest in looking at it, that it would be -- it would be better to aggressively phase out the declining block rate as quickly as you can. And just to add, I would agree wholeheartedly that you would need a massive customer education effort that this is coming, because otherwise it's not going to do any good. Because in fact the most substitution that you can do in response to the price involves expending capital, either putting in insulation, changing the heating system. Reacting to those things takes some time.

We can all turn down the thermostat and put on sweaters, but in the longer term most of the substitution that you get from a price signal like that relates to making some investment either in your business or in your home to be more energy efficient.

CHAIRMAN: Okay. And I don't know if you were present when Mr. Larlee talked about the 200 meters that Disco is going to be purchasing in the next year in reference to the residential sector, but certainly in response to me he agreed that the price of that meter would be somewhere in the vicinity of $300, each individual meter.

I think I heard you in direct again talking about the general service classes and that there was no metering involved there. Are you familiar with or what the nature would be the same sort of meter that Disco was planning on purchasing, i.e., would the cost be the same if you wanted to get into a proper load data collection in that kind of customer class? Or would it be more expensive or less?

A. I can't say I'm an expert in load research but I believe that to get an interval meter that would be able to record the consumption on an hourly or less than hourly basis would probably be the same.

It may have to be bigger to apply to a larger general service customer. And small businesses in many ways have the same load profile as residential customers and aren't noticeably larger, but as you move up they might be more expensive. Again I'm not an expert on load research.

CHAIRMAN: Okay. And then again further on in your direct you talk about if you want to put your rates on -- based on market it would have to -- Disco would have to upgrade its load research as well. Would this -- what you are

suggesting in reference to the general service I and II and those meterings -- would that give you that kind of information?
A. Yes, sir.
CHAIRMAN: Okay. Mr. Morrison, was Mr. Larlee able to pinpoint for me where it is?
MR. LARLEE: Yes. I found the references that you alluded to.
CHAIRMAN: Okay. What would that be, sir?
MR. LARLEE: You were asking specifically?
CHAIRMAN: I believe you talked about how you would take the sample and that there was a residue of volunteers that were there from before and that you were going to go back to that sample of people and get 200 of them and instal the meters or upgrade or whatever, and that's what you -- you sort of defined the methodology.
MR. LARLEE: On page 1092 --
CHAIRMAN: And that's on the same day?
MR. LARLEE: That's on the same day, yes. And I believe that's the only time we discussed load research.
CHAIRMAN: Okay.
MR. LARLEE: On line 11 I start to describe basically how we can produce load profile data on the residential class, which numbers in the order of 300,000 customers, using 200

sample points.

I agree with you that that seems like a very small sample, but what I do is I go on and describe the technique -- statistically valid technique -- of producing that type of sample, and it's called stratified sampling.

CHAIRMAN: Okay.

MR. LARLEE: So that's the discussion where basically I'm describing the overall technique. I'm not sure there is anything in that discussion where I talk about the 200 meters that we are going to be purchasing in the coming months. But that is in the evidence.

Basically what it is is that we are replacing the aging existing meters of the load research sample with new meters using the exact same customers.

CHAIRMAN: Well question 810 -- sorry -- it would be just prior to that, because question 810 by Mr. Hyslop is -- and do you consider 200 meters as being a satisfactory sample? So that was discussed previously.

Anyway, all of that having been said, Mr. Knecht, were you present and do you remember that discussion?

A. I believe I was present and I remember it generally.

CHAIRMAN: And in your opinion is that a sufficiently large sample in the way in which the sample is chosen from volunteers -- is that an appropriate way to go?

A. I guess I would fall back on my defence that I'm not really a load research expert and not really a statistician. Again it depends on the homogeneity of the load and how well you can reflect that in the individual strata that you see.

You know, the concern that I expressed the other day that, you know, if you have these large farms and churches and a set of those customers in this class, that may -- those customers may have very different profiles than your average residential customer. But it becomes a question of statistics and I think you have to look at the details and --

CHAIRMAN: But that would have been --

A. -- it goes a little beyond my expertise.

CHAIRMAN: Okay. Thanks, Mr. Knecht. Those are all my questions. Mr. Hyslop?

MR. HYSLOP: Thank you, Mr. Chair. I only have a couple of questions. None of them deal with follow-up on the multiple regression of forming a line to find a zero intercept.

CHAIRMAN: What is the matter with you, Mr. Hyslop?

<u>REDIRECT EXAMINATION BY MR. HYSLOP</u>:

Q.454 - In any event, Mr. Knecht, Mr. MacDougall and I believe also my colleague Mr. MacNutt asked a number of questions

regarding marginal cost in respect of cost allocation studies.
And there was a lot of discussion. I just want to be clear and clarify for the record. The first part of it I guess is what was the purpose of introducing the discussion of marginal costs into your evidence?
A. The purpose of introducing marginal cost was to use it as a proxy for market pricing if the Board decides that it wants to reflect the restructuring of NB Power into its cost allocation procedures over the next few years.
Q.455 - And do you -- are you making any specific recommendation to the Board that it accept the marginal cost approach for cost allocation at this proceeding, or where do you stand on that?
A. As I said, I think that's a policy decision for the Board and I am comfortable leaving it with them.
Q.456 - There was a question Mr. MacNutt asked with regard I believe to the zero intercept methodology and transformers and relating to the number of transformers. I think subsequent to giving that answer you had a quick look at the NARUC manual, and could you advise how what you found in that impacts on your answer, if any?
A. The -- I believe that Mr. MacNutt's question related to the minimum system approach as it applies to transformers, and whether or not the number of

transformers would change when applied to a minimum system basis. So I looked it up in the NARUC manual. I have now lost the reference.

It would be on page 91 -- 91 to 92 of the NARUC manual under category A, the minimum size method, account 368, line transformers, and it says, determine the minimum size transformer currently being installed, multiply the average installed book cost of minimum size transformers by the number of transformers in plant account to determine the customer component, which was my understanding of how the minimum system method would apply for transformers.

As we said, neither Disco nor I or Commissioner Sollows is using the minimum system method as it is described in the NARUC manual.

Q.457 - And finally my last question, and this came out of one of your answers to Mr. Sollows, and your answer -- or the question was relating again to which jurisdictions use these basic customer with 100 percent demand and zero intercept minimum systems. And you answered that in the United States consumer advocates vigorously take the position that we should be working off the 100 percent demand system. And as I recall I have been taking the position we should be using the zero intercept.

And my question is does that imply I haven't been doing my job very well?

CHAIRMAN: You don't have to answer that.

A. I was going to respond that my suspicion was he hired the wrong expert.

MR. HYSLOP: Those are all my questions, Mr. Chair. And I thank Mr. Knecht for having to make multiple trips to New Brunswick from Massachusettes to appear at these hearings, and I hope his evidence has been helpful. Thank you.

CHAIRMAN: Thank you, Mr. Hyslop, and thank you, Mr. Knecht, for your testimony. And we shouldn't have to thank you for making multiple trips to New Brunswick. You should be thanking us.

MR. KNECHT: It has been a pleasure. I thought my counsel was getting me further into trouble.

CHAIRMAN: Okay. Thank you very much, Mr. Knecht. You are excused sir. And we will break for lunch and come back at 1:00 o'clock.

(Recess - 11:45 p.m - 1:15 p.m.)

CHAIRMAN: Good afternoon, ladies and gentlemen. Any preliminary matters? This afternoon with agreement from all the parties, why Mr. Garwood is joining us via telephone in some marvellous electronic fashion. Are you there, Mr. Garwood?

MR. GARWOOD: I am.

CHAIRMAN: I think that was a yes?

MR. GARWOOD: Yes.

CHAIRMAN: Yes. Good. We wish you a speedy recovery.

MR. GARWOOD: Thank you.

CHAIRMAN: And I am going to ask the Secretary to swear the witness that is present and I will get to you in just a minute, Mr. Garwood. Mr. Garwood, you have a Bible, I understand?

MR. GARWOOD: I do.

CHAIRMAN: Good.

ARTHUR ADELBERG, STEVEN GARWOOD, sworn:

DIRECT EXAMINATION BY MR. MACNUTT:

CHAIRMAN: The one thing that I have run into in using a teleconferencing like this is that sometimes we start to speak before the question is finished and vice-versa, and the phone does not pick up one side of that conversation. So I would ask counsel and yourself to be cognizant of that and allow the questioner to finish and then if you are a questioner to allow the witness to finish. Okay. Mr. MacNutt.

Q.1 - Thank you, Mr. Chairman, and good afternoon, Mr. Garwood and Mr. Adelberg and Chairman and Commissioners. Now, Mr. Adelberg, would you please give us your name, address and business affiliation?

MR. ADELBERG: Yes. Arthur Adelberg, Energy Advisors LLC, 40 Spring Brook Hill Road, Camden, Maine.

Q.2 - And, Mr. Garwood, would you give us your name and address and business affiliation?

MR. GARWOOD: Steven Garwood, a member with PowerGrid Strategies LLC and also Energy Advisors LLC, and my business address is 249 Western Avenue, Augusta, Maine.

Q.3 - Thank you. Now, Mr. Garwood, you have a copy of your report which is exhibit PUB-1?

MR. GARWOOD: I do.

Q.4 - Thank you. And, Mr. Adelberg, you have a copy of your report which is exhibit PUB-1 in front of you?

MR. ADELBERG: I do.

Q.5 - Now Mr. Adelberg first and then I will go on to Mr. Garwood. Please confirm that this is your direct evidence in respect of the reasonableness of the class cost allocation study and rate design recommendations submitted by Disco in respect of its request for approval of rates in the present matter. Mr. Adelberg?

MR. ADELBERG: It is.

Q.6 - And Mr. Garwood?

MR. GARWOOD: Yes, it is.

Q.7 - Now, Mr. Adelberg, would you confirm that your portion

of your direct evidence in exhibit PUB-1 was prepared by you or under your direct supervision?
MR. ADELBERG: I can. I do.
Q.8 - Do you adopt this evidence as your evidence in this matter?
MR. ADELBERG: I do.
Q.9 - Mr. Garwood, you would confirm that your portion of your direct evidence in exhibit PUB-1 was prepared by you or under your direct supervision?
MR. GARWOOD: Yes, I do.
Q.10 - Do you adopt this evidence as your evidence in this matter?
MR. GARWOOD: Yes.
Q.11 - Now, Mr. Adelberg, your CV appears at page 1 of exhibit PUB-1. Could you give us just a very brief synopsis of your background?
MR. ADELBERG: Yes. I am by training -- I have a degree in law. I have been a consultant essentially since the year 2000. I was in senior management at a public utility for 15 years, during which time I had a supervisory responsibility for rates and rate regulation matters. And prior to that time as a practising attorney I handled rate -- cost allocation and economic issues relating to rate design for the electric -- for the railroad industry.

Q.12 - Thank you. And, Mr. Garwood, your CV appears at page 2 of exhibit PUB-1. Would you please provide us with a brief synopsis of your background?
MR. GARWOOD: Yes. Prior to going into the consulting field in 2000 I worked for Central Maine Power Company and an affiliate -- Maine Electric Power Company and then later the company that purchased both of those companies, Energy East, for approximately 17 years. And I worked in engineering, rates and cost of service, and then later in positions dealing with all of the aspects following out of FERC's attempt to re-regulate the transmission business. And I served in a variety of positions including entry level positions on up through executive management positions.
MR. MACNUTT: Thank you. Now, Mr. Chairman, I would move to have both witnesses qualified as experts based on -- as follows, based on the background and experience of each of the witnesses, I move that they be declared an expert in utility cost allocation and rate design.
CHAIRMAN: Are there any objections? If not, the Board will accept them as that.
MR. MACNUTT: Thank you.
Q.13 - Now, Mr. Adelberg, I understand you have some corrections you wish to make in respect of your report,

exhibit PUB-1?

MR. ADELBERG: I do. Thank you. I have two corrections that are immediately in the text of the -- of our direct evidence, and then a third that relates to some tables that were provided in response to an interrogatory that were substitute tables for the tables in the text.

The first change appears at page 13 of our direct evidence and it's in footnote number 4, and the change is to strike the portion of that footnote beginning the 68/32 ratio appears through the end of that footnote. That statement in which we opined that Mr. Ketchum had made a mistake was in fact our mistake. We had not fully understood his analysis until it was further explained in the proceedings. So that correction needs to be made.

The second correction is more minor and it's on page 78, line 19, and it's the line beginning, of large industrial loads, and it says, were lost do to self-supply. That should be due, spelled d-u-e, not d-o.

And then as I mentioned, the third has to do with the tables and our report has a series of tables that were designed to identify the impact on revenue cost ratios of the various changes that we suggested to the company's approach or other issues that we raised. We were trying to single out the impact of those.

The way the tables were set up the impact of our changes was generally shown on where there are multiple columns it would be the right hand column. And there is one exception to that which we will come to in a minute, but generally speaking that was where we put our changes. In the course of -- the other two columns in those tables where there are multiple columns were designed to have some base to compare against. And when we responded to PUB PI IR-1-3 we realized that the comparison columns that we gave were probably not the best ones for making the points that we wished to make. So we re-issued those tables in response to that IR, which again was PUB PI IR-1-3.

MR. MACNUTT: And for the record, Mr. Chairman, that was September 23, 2005, exhibit PUB-2.

MR. ADELBERG: And so again the -- and that sort of table has also had an additional table on the back which was in response to -- I believe that IR was just to ask for a little more detail, so we had broken out some of the data. In going through and getting ready for the hearing we noticed that in table number 6 there were a few lines where we had inadvertently transposed some data and they are -- on the version that we made -- of which we made copies for the Board this morning, they are noted by being shaded and the table 6 corrected.

And they are -- for those who had received our tables as data responses or interrogatory responses before they would have noticed this because this -- these figures are essentially the same for those classes as appear on the next table.

In any event, to eliminate those mistakes we put the corrected numbers in those shaded boxes and they are for the street lights and unmetered class. The correct number should be 1.680. For water heaters it should be 1.570. The large industrial total is 0.953 and wholesale is 1.050.

And so those are our corrections.

Q.14 - Thank you. Now I'm going to ask both of you some questions in respect of the pre-filed evidence, direct evidence, and evidence given on cross examination of several of the witnesses in the present matter before turning to your evidence.

Now, Mr. Adelberg, have you had the opportunity to review Mr. Ketchum's direct evidence which appears in exhibit A-3 at tab 3?

MR. ADELBERG: Yes, I have.

Q.15 - Now you were present during Mr. Morrison's direct examination of Mr. Ketchum and Mr. Ketchum's cross

- 1989 - Messrs. Adelberg and Garwood - Direct - examination by various participants?s?

\ MR. ADELBERG: I was.

Q.16 - Now as well you have had the opportunity to review the transcript of those examinations?

MR. ADELBERG: That's correct.

Q.17 - Now Mr. Ketchum was asked by Mr. Morrison whether he agreed with the recommendation of Energy Advisors that Disco should move to marginal cost analysis as the basis for cost allocation.

Mr. Ketchum responded, "What we are looking at now is no longer a vertically integrated utility, but a restructured utility that sees marginal costs as the prices it pays for capacity and energy in the contracts as opposed to looking at resources and looking at how they would be dispatched and what would be saved by reducing demand one kilowatt or that sort of thing.

So I think, you know, based on those kinds of considerations that full blown I would say kinds of traditional, longrun incremental cost of marginal cost studies as we used to think of them say in the '80s and '90s, doesn't seem to -- wouldn't add any great value at this point in time."

And that can be found for the record in the transcript of September 26th 2005, at pages 803 from the last line to page 804, line 13. Would you care to comment on that?

MR. ADELBERG: Yes. I'm very sympathetic with the challenge that the company faced in attempting to identify the appropriate principles to apply to cost allocation and rate design given the province's policy of unbundling and restructuring the industry and taking steps towards a more competitive model.

And I agree that the contracts that have been put in place would -- are relevant and we will discuss in more detail how so, but they are relevant to looking at what the costs of generation will be going forward and how those costs should be allocated and designed into rates.

The problem is that, as you heard already from other witnesses in this testimony, the step that was taken in restructuring was a very modest one in contrast to some other utilities that were actually compelled, such as mine, to sell off their generation entirely to an unregulated entity.

In this case you have an affiliated company that has essentially the same portfolio of assets and moreover is billing them back to the Disco in a manner that looks very, very similar to the costs that they would have seen if they were still an integrated company.

So the question arises how do you -- how do you allocate costs and design rates under those circumstances? Do you move entirely to a market model and assume that these are contracts like you would see in a fully competitive market, or are you still somewhat in a regulated world? Clearly you are not completely at one end or the other, but we were uncomfortable saying that if you are going to continue to look at embedded costs in particular, that you have moved enough away from the traditional model that the principles of embedded cost allocation would not still apply.

Having said that, as you can probably discern from our testimony, and certainly you will hear more of that, in the old regulated world the way that regulators and others addressed cost allocation and rate design in an effort to introduce more efficiency in the pricing was to look at marginal costs, to look at forward looking costs. The difference being in those days, as Mr. Ketchum quite correctly points out, there wasn't enough of la competitive market to get competitive market price signals from market information. So what you did was you attempted to mimic that by looking at what you thought a competitive market would produce for prices by looking at marginal cost studies.

Again, we are now moving away from that era, but it is still -- it's still relevant that we want to set prices efficiently for New Brunswick Power. And even though -- even if we haven't moved to a competitive market the same reasons that supported use of marginal cost analysis in the past in our view still apply today. In our view the question is more how do you want to apply those principles than whether you want to apply those principles.

And I think if you -- and to respond to that question I think you will find that our views are very similar to those of the previous witness, Mr. Knecht, who talked about his approach as being a marginal approach but said he would look at the -- at what he called market approximation. He would attempt to look at marginal prices and marginal costs through what was going on in the market.

What we have found from our experience here and our experience elsewhere is that even if you had a much more competitive wholesale market and if you had a market that was as developed as some of the competitive markets, for example, in the northeast United States, but the peculiar thing that is being learned is that while the competitive market is -- does appear to be sending hour by hour signals of marginal costs that probably reflect a good deal of competition, to the extent that parties are entering into power supply arrangements in these markets, even under longer term contracts, the pricing under those contracts is not necessarily the pricing you would want to have reflected in your retail customers. Because for one reason or another, regulators and utility companies and others are often asking for flat prices, even though the actual underlying costs very seasonally or hour by hour. So in the final analysis if you want your customers to see price signals that will cause them to make wise decisions about the use of energy, regulators in the United States are beginning to think that perhaps they cannot simply flow through those market prices.

They may have -- they certainly use them as the basis of the costs that retail customers will see, but they may need to design them to some extent to make sure that there are efficient price signals that come through.

So that's all a long way of saying that we are in a state where, you know, we haven't moved fully to competition, but even if we had, there would probably be value in an approach that looks forward and attempts to set price signals based on where we think costs going.

And this is of course particularly an acute problem for the province now, because prices are -- seem to be changing precipitously. And it would be, we think, of considerable value to try to incorporate as much of that information as we can into retail rates, so that customers don't continue to make decisions, for example, to use electric heat when in fact the longterm cost impact of doing that is far greater than they may have been assuming to date.

So it's a tough issue in the sense that we are -- we are in one of those areas where we are moving from the old world to the new world. There is lots of difficult sub-issues that have to be addressed. But we feel that this Board would profit by having information on marginal costs and we will be glad to talk further about some of our thoughts on how you would develop that. But it would be useful information to have in attempting to set the most efficient rate structure possible.

Q.18 - Thank you. Now continuing with Mr. Ketchum's testimony in respect of marginal cost analysis, he was asked by Mr. Morrison whether he agreed with the statement by Energy Advisers that "marginal costs offer the only escape from the realm of subjectivity."

Mr. Ketchum responded that based on his experience, marginal cost studies, "require a lot of judgment which puts us right back in the realm of subjectivity." And for reference that is transcript of September 26th 2005, page 805 lines 17 to 19.

What comments do you have in respect of that testimony?

MR. ADELBERG: Mr. Ketchum's response is a fair one. And other witnesses I think have made the same point. And I think the problem perhaps is my choice of words. But here is the point I was trying to convey.

It is well recognized and even other -- Mr. Knecht, for example, this morning testified along the same lines that it is as a matter of theory, mathematics and every other principle I can think of, impossible to perform a precise cost allocation study using embedded cost principles, because you are attempting to allocate costs that are joint or common and cannot be causally attributed to a single party through a process of allocation. So no matter how precise you get, you are going to be precise -- you know you are going to be precisely wrong in the final analysis.

The difference -- and this is a longstanding debate, margin cost theory does have at its focus something that is objectively does exist. So when I was talking about objectivity, I was talking about the fact that there was an objective goal that you are trying to reach for. And having said that, I will not only readily concede that there is judgment in the measurement techniques you use to get to that goal, but in fact in our testimony, we outlined and discussed some of those problems in some detail and we readily admit it.

But what it always comes down to in this debate is the choice between being precisely wrong or approximately right is -- or precisely wrong or approximately correct, that's the way that the debate is often cast.

And you will probably have heard and you will probably hear some more about the relative difficulty of doing marginal cost studies versus doing embedded cost studies.

And you will have to decide for yourselves whether you are comfortable that there is enough -- enough -- that the complexities of marginal cost can be overcome sufficiently to make it worthwhile to do the exercise.

And I would only also point out that in 1992, the Board did apparently look at that same kind of issue, the same debate and directed the company to look at longrun incremental costs, which is a variety of marginal cost analysis. That was done in the Reed Report. And the Reed Report concluded that they did not -- further pursuit of that issue.

In our testimony, we responded to the Reed Consulting analysis of that. But -- and so if we want to get into that we can, but my point is this is not a new issue for this Board. It's one the Board has looked at before. Apparently, concluded at one time that it was at least worth exploring further and you sort of reached a dead end in 1993. The issue went away. But it's -- I do think it is fair issue for this point in the proceeding.

Q.19 - Thank you. Now again, Mr. Adelberg, on October 6th 2005, I asked Mr. Ketchum a series of questions relating to whether incremental costs or embedded costs were a better method of determining the existence of cross-subsidies. Mr. Ketchum responded by saying "Well, I think that what Energy Advisers is trying to get at here is a marginal analysis of cross-subsidies." And for the record that's the transcript October 6th 2005 at page 1436 at lines 8 to 10. What comments do you have on that?

MR. ADELBERG: Again, this is maybe just a matter of a choice of words. And it may be that Mr. Ketchum was -- and I are on the same wavelength on this, but we would distinguish between -- for this purpose, between an marginal cost analysis and an incremental cost analysis and the reason is this. Marginal cost analysis that is done for -- and typically a marginal cost study, which is done for setting retail rates, is as Mr. Ketchum has explained. It's a fairly elaborate process that gets into hour by hour costing and looking at very, very small increments of -- the impact of very, very small increments of load changes.

For a cross-subsidy analysis, while the economic principles are similar, there is a difference. What you are looking at in a cross-subsidy analysis is not the impact of at least under the theory that we are supporting in this case, it's not simply -- you are not looking at the impact of a small change in load. You are looking at the incremental cost of serving a class.

And there are techniques that you can employ and are employed in that analysis that are somewhat different and perhaps not as detailed as you would have to get into in a marginal cost analysis that would still be useful for looking at the incremental cost of serving a particular class of customers and which can help shed light on the real question of whether cross-subsidies exist in your rate structure and without doing the traditional full blown marginal cost study.

Q.20 - Thank you. Now a question for you Mr. Garwood. Have you had an opportunity to review Mr. Ketchum's direct evidence, which appears in exhibit A-3 at tab 3?

MR. GARWOOD: Yes, I have.

Q.21 - Now you were present during Mr. Morrison's direct examination of Mr. Ketchum and Mr. Ketchum's cross examination by various participants?

MR. GARWOOD: Yes, I was.

Q.22 - Now as well, you have had the opportunity to review the transcripts of those examinations?

MR. GARWOOD: Correct.

Q.23 - Now during Mr. Morrison's direct examination of Mr. Ketchum on September 26th 2005 concerning the classification of credits from power sales by Genco to third parties, Mr. Ketchum stated, "Disco sees the credits as being applied to the fixed cost portion of the contract by Genco and the credit comes down to Disco as billed as a credit of the fixed cost." And just for the record it's in the transcript, September 26th 2005, page 813, lines 3 to 5.

What comments do you have with respect to what I have just quoted for you?

MR. GARWOOD: We reviewed those invoices and I think those are -- those were provided -- copies of those were provided I believe in PUB IR-80, if I am not mistaken. And from our review of those invoices, the credits at issue appear to be just a total dollar credit applied against the total bill.

So from our review, we didn't see that they were specifically credited against the fixed or demand charge components of the bill. And again that therefore didn't sway us from our original belief that the proper way to reflect the credit was on the same basis that described the transactions that derived the credits in the first place.

Q.24 - Thank you. Now, Mr. Adelberg, a question with respect to Mr. Marois' testimony. On September 28th 2005, I asked Mr. Marois about seasonal rates. Mr. Marois stated at page 1127, lines 8 to 10 of the September 28th transcript, that his "concern with seasonal rates is the additional complexity that it introduces from both the utility but also from the customer's perspective." What comments do you have with respect to that testimony?

MR. ADELBERG: I think as distinguished from the complexity of time of day rates that change several times a day and throughout the week, the complexity as you have heard from other witnesses, is fairly minor. In a seasonal rate change you are talking typically about a rate change in the fall and a rate change in the spring, and it's one that does not require any change in metering. You use the same meter data that you have now. It's one that basically requires a different input into your billing system.

The complexity is certainly far less than was suggested by one of the other alternatives that Mr. Marois mentioned when he was reviewing some of the possibilities that they were -- that they had examined. At one point he talked about rates that would have changed to reflect differences in monthly fuel costs.

Again maybe a desirable or admirable outcome if you are trying to send price signals in a very volatile market, but from a complexity point of view, that would be far more -- you know -- a far greater complexity than simply changes in rates twice a year.

And in suggesting this we are not at the same time arguing that necessarily if you buy into seasonal rates you necessarily have to attempt to incorporate the full amount of seasonal variation that you think will exist. You can start down that road with a very minor change in seasonal rates, but in doing so you begin to lay the groundwork for customers to understand that this is part of the changes to come and part of the costs of using energy that they are going to need to react to over time as they make their own decisions about energy use and energy investments.

Q.25 - Thank you. Now we are going to turn to the testimony of Mr. Larlee. I address this to you, Mr. Garwood. I'm now going to turn to Mr. Larlee's cross examination by Mr. Hyslop on October 4th, at pages 1260, line 20, to page 1261, line 7, of the transcript of October 4th.

Mr. Hyslop read from the direct evidence of Energy Advisors where you stated that your recommended approach to the allocation of transmission cost to customer classes was consistent with the policies of the US Federal Regulatory Commission. In response to a question by Mr. Hyslop, Mr. Larlee stated that he agreed that FERC does not regulate the affairs of Disco.

What comment do you have in respect of that statement by Mr. Larlee?

MR. GARWOOD: Well I would agree that FERC doesn't regulate Disco. However, with respect to the design of New Brunswick's open access transmission tariff where -- when I was employed as a consultant with another firm during the design of that initial tariff, clearly the goal that I was under direction to assist the company with was to try to come up with an open access tariff that had rules and policies as similar as could possibly be made with respect to the FERC rules and regulations that FERC imposed upon US utilities.

So although I recognized the fact that they are not under the jurisdiction of the FERC, clearly my understanding of the direction of the company and the policy makers in New Brunswick were wanting the open access tariff to move towards was one to be consistent with the way FERC had regulated the US utilities on this matter.

And I think my understanding was that direction I was being given from the company on that matter stemmed from statements in the energy policy White Paper. For instance, right in the introduction of that there is a statement that says there is no option but to become part of what is developing into an fully integrated North American electric supply and marketing grid. In order to participate and to continue to capture the benefits of a competitive market, New Brunswick must operate by rules and procedures compatible with those established by the FERC.

So that's the way I viewed that situation.

Q.26 - Thank you. Now, Mr. Garwood, you have recommended that Disco create new rate sub-classes based on the voltage levels at which customers take service, and provide its analysis of the effects of doing so. Mr. Larlee testified that Disco does not currently have the data necessary to create separate sub-classes based on voltages and questioned how you were able to perform your analysis. Can you explain how you were able to do that analysis?

MR. GARWOOD: Right. First I would state that we really view that this is something that deserves more exploration. It's in my experience more common than not, that there are differing costs in serving customers at various electric levels, and so it's very common to have differing rate classes to put those customers into.

And the analysis I had done using the company's own data in its originally filed CCAS from what I could tell lent itself to being able to show what the cost was for those two sub-classes, primary and secondary, under GS I and GS II rate classes. And the results that that produced just led me to believe that it deserved more examination.

But the way in which I was able to produce those results was -- in an 11 or 12 step process I have laid out for myself to document how in fact I accomplished that. It's rather detailed and I won't go reading through that. But essentially most of the -- many of the original schedules that comprised the company's original CCAS, actually had already shown primary and secondary sub-classes under GS I and GS II broken out separately.

And so working with that level of information really allowed me to go ahead and expand the other worksheets or schedules that had not had that level of detail shown to show this cost differential.

For instance, in the first few work sheets which simply derived the demand and energy allocation factors or the customer allocation factors, we will for the moment ignore customers, but the energy and the demand allocation factors, the company's original schedules already showed the breakdown between primary and secondary.

In fact the customer -- weighted customer allocation factor, schedule 1.4, was the first schedule that I had to do something with, because it didn't explicitly state the number of primary customers to derive your customer allocation factors.

It stated the total number of customers in the GS I class or the GS II class and it stated the number of secondary customers. So it was just a matter of taking the difference between the total and the secondary to allow you to come up with the number of primary customers. And so I modified that schedule so that I could have a customer allocation factor to use when allocating customer related costs throughout the study.

And in that particular one the only assumption that I had to make to move forward from there was on that schedule you actually develop weighted customer costs -- weighted customer allocation factors based on the relevant cost of meters to serve these various customers.

And at this stage I simply assumed that they were the same for the secondary and the primary customers. And so that's one example where a refinement to what I have done might be required as you were to further examine cost differences to serve these customers. But with the information I had, again I assumed that to be the same and moved forward.

And once I had derived that customer allocation factor, many of the changes that I had to make thereafter were simply inserting rows to accommodate showing a row for primary and secondary customers on the sheets where the company's cost of service study did not already have them broken out separately.

And so that would include schedules 4.1 which showed the allocation of net plant to the various classes or sub-classes, 4.2 which showed the O&M that was allocated to the rate classes, 4.3 which was the depreciation and amortization on plant, allocating those to the various classes, 4.4 which was the financial -- financing costs being allocated, and then 4.5 which simply summed up the total costs from all those prior sheets.

So really from that point it just simply became the mechanics -- a mechanical exercise of inserting the rows, copying down the formulas appropriately, and it just simply fed back to -- or pulled the information from the prior sheets which, as I stated, the only one I had to modify was the customer allocation sheet on schedule 1.4. Transmission service cost allocation, which showed up on schedule 5.2, was one that I had to make another assumption. In the -- whereas the company had used a 12 NCP or the average of the 12 NCPs for allocating transmission costs, and back on -- I forget now if it's either 1.3 I think it is -- 1.3 -- had just a single NCP as the demand allocator for some of the other costs. That schedule actually showed the single NCP for total GS I, total GS II, and for the sub-classes, primary and secondary under each of those classes, I simply applied the same percentage ratio that primary or secondary was of the total, I applied that same percentage to the 12 NCP of the class totals shown on the company's 5.2 schedule to come up with a 12 NCP number applicable to primary and secondary sub-classes. So that was another assumption I made in the mechanics of my analysis to show the cost differential.
Beyond that again, moving over to schedule 6 which was

the schedule that allocated miscellaneous revenue to come up with total revenue applicable to each class. It was just a matter of inserting the rows to accommodate primary and secondary sub-classes and then feeding back to the sheet I described, revising for customer allocation factors, because some of the miscellaneous revenues were actually utilized the customer allocation factor to allocate the miscellaneous revenues to the classes and sub-classes. And then from there a similar insertion of rows was made to accommodate these sub-classes on schedule 6.1 which was the total revenue requirement schedule, and also the schedule that produced the resulting RC ratios.

So I think all of my work that I did to modify the CCAS to show the breakdown between primary and secondary under the GS I and GS II classes was all contained within information that already existed in the company's original filing. And I think I only made a couple of minor assumptions to get where I got to with that analysis. And as I stated earlier, that said, the results showed that this warranted further examination and perhaps bettering some of the data that I had used where I made some assumptions to get there.

Q.27 - Now further turn to Dr. Rosenberg's evidence -- and this is addressed to you, Mr. Garwood. Have you had an opportunity to review Dr. Rosenberg's direct evidence, which appears in exhibit EGNB-1?

MR. GARWOOD: Yes, I have.

Q.28 - And have you had an opportunity to review the transcripts of those examinations?

MR. GARWOOD: I have not reviewed the transcripts.

Q.29 - Oh, I am sorry. You have had an opportunity to review, as we just identified, Dr. Rosenberg's evidence in exhibit EGNB-1, is that not correct?

MR. GARWOOD: That is correct.

Q.30 - What comments do you wish to make in respect of Dr. Rosenberg's pre-filed evidence?

MR. GARWOOD: Well, my comments focus on Dr. Rosenberg's analysis for the allocation -- classification and allocation of generation costs. I think we have referred to his method as either the fuel symmetry theory -- or a method to support his fuel symmetry theory or sometimes I have called it his break even analysis, which was a complicated analysis, but as we dissected it, we found that it kind of broke down into some discreet components. And before we get to those components, some of the problems we had with his analysis -- well maybe I will back up and describe that analysis a little bit.

His analysis was one where he applied the Peaker

Credit analysis to each specific plant to determine the component of the plant costs as capacity versus energy. And unlike -- unlike using say the 40/60 demand energy split that was approved by the Board, and not necessarily tied to the Peaker Credit approach, by having used the Peaker Credit approach the way in which Dr. Rosenberg did, he arrived at using a different demand energy split classification for each category of plant I guess I will call it. A different split for nuclear, for hydro and for other technologies.

One of the first things we noticed was that his treatment of hydro it didn't necessarily represent the way in which the company's hydro operated. I think he had assumed the flat use of hydro 87/60, when in fact I think some evidence has been submitted already in this case that showed the company's hydro facilities aren't operated in that fashion.

Aside from that once he had derived the percentage of plant costs that were deemed capacity-related using the Peaker analysis, he then went and, as I will state, compressed -- as I will describe it, he compressed the recovery of energy costs over what I will go ahead and call some arbitrary periods or months of the year. And recognizing that he -- as he stated -- he didn't have the hourly data indicating when these plants were actually operating. And so we had trouble with what I will call the arbitrariness of selecting the months at which these plants operated.

In the end, as I have stated, we were able to dissect the analysis and came up with about three buckets that the -- three bucket of shifting of costs that occur, and I will say shifting of costs to the residential class resulting from his analysis. And when you look at, I think it's better to look at it within those buckets.

As I stated, his analysis utilized a Peaker Credit approach where he then applied technology-specific, demand energy splits to the facilities. If you simply -- and if you simply correct or revise Dr. Rosenberg's analysis to use the 40/60 split, as approved by the Board in I think the '93 CARD decision, and I believe I understand that Dr. Rosenberg has re-done that and his work was marked as exhibit EGNB-3, if I am not mistaken, and I received that by e-mail earlier this morning, I think that shows a difference of about $5.3 million, meaning that when you correct for using the Peaker Credit approach, as he has done to using the 40/60 split of demand energy on all of the generation, you actually relieve about $5.3 million of revenue requirements from the residential class that Dr.

Rosenberg's original analysis had placed on that class.

Additionally, Dr. Rosenberg had applied a different sales or a third party sales credit split that the company had done and in fact he actually agreed with our own analysis of where the -- of how the sales credits should be applied. And so my analysis indicates that instead of using -- instead of allocating the credits, a hundred percent demand as the company had done, and instead allocating those among demand and energy based on the sale transactions we reviewed, that alone had another $2.3 million of impact to the class -- or the allocation of cost to the residential class from that which the company had originally filed.

So that in itself is between 7 and $8 million of cost alone. And I believe the balance of the difference in the cost have been allocated to the residential class, shifted to the residential class as a result of Dr. Rosenberg's analysis is tied up in the what I will call the compression of energy costs among the -- what I will call the arbitrary months or the shortened time period for which he has attempted to recover those costs. And again his original work appeared to shift about $13.4 million to the residential class. But as I stated, if you break it down into its components, it appears the lion's share of that comes from simply using the Peaker Credit approach and applying a different demand energy split using that method to the various technologies of generation versus the 40/60 demand energy split approved by the Board.

So again for I guess -- it seemed to be a very complicated way of getting around to the impact, but it seems to me that it all really goes to the compression component of the analysis if you assume that the Board's position on the 40/60 is to be maintained from its prior decision and you take away the effects of the sales credit. And we believe that that impression of recovery of the energy costs over the -- the way in which Dr. Rosenberg did it was rather arbitrary.

Q.31 - Thank you. Now, Mr. Adelberg, on October 26th 2005, Dr. Rosenberg during his direct examination by Mr. MacDougall expressed his reasons for supporting a cost causation approach to cost allocation. And that appeared in the transcript October 26th, at pages 1498 to 1500. Do you remember that testimony?

MR. ADELBERG: I do.

Q.32 - And what comments do you have in respect of it?

MR. ADELBERG: As I recall, Dr. Rosenberg offered eight or nine reasons for his preferred approach to using cost causation. And one that struck me as particularly interesting was -- I think it was his number 5, where he said that it was important to use cost causation as a principle for rate design and cost allocation because you need to have a level playing field between electricity and other forms of energy use or conservation for that matter. And, of course, competition between electricity and natural gas is obviously a concern to his client. To our mind that is a very compelling argument for looking at forward looking cost using a market approximation or marginal cost based approach, because I suspect that where natural gas prices or the price of using gas to heat is probably going to reflect very much the forward looking costs that we are seeing right now and we are projecting over the coming period, because natural gas prices are very high. I think that in order to have a level playing field from electricity, you would not want to have that cost structure and a rate design that's based on things such as hydro plants that may be heavily depreciated because they were installed decades ago. You would want to have in order to have a level playing field where you can see the true economic costs of the alternatives, you wouldn't want to have electricity price based on marginal costs. And so there are reasons why you can't get precisely to marginal costs, which again have been discussed and will be discussed further. And as between marginal costs and embedded costs, I would think the most level playing field would be one where you have marginal costs.

And it was particularly -- I was particularly attuned to the discussion that took place earlier in the proceedings about the relative efficiency of electricity and natural gas. And as a former electric utility executive, and for that matter, a gas utility executive since we were also in the gas business, I am very mindful of the fact that heating -- residential heating with natural gas can now approach efficiencies of 90 percent. If you take that gas and run it through electric generating facility and then use it to heat in your home, you are going to typically get an efficiency of half or less, maybe even -- depending on the technology you use to generate the electricity, it could be as low as a third. And that suggests that the scenario such as you have today, where you are -- one of the data responses indicated that the cost under current rates of heating with electricity still is lower than gas.

And then when you take into account the cost of putting in a gas furnace there is something very wrong with that.

And I think that the best outcome that you can hope for is one where you have both -- where you have electricity price on the margin -- as close to marginal cost as possible, because then customers will see the true cost differences and they can make decisions based on the true difference and the efficiencies of those technologies.

I say this mindful of the very painful experience that we are having with natural gas prices. But the fact of the matter is that you are going to mask the relative economics of electricity versus gas when you have one that's -- your gas that is reflecting today's prices and you have electricity where the rate structure is reflecting in some cases very old investments.

Q.33 - Thank you. Now Mr, Adelberg, do you recall Dr. Rosenberg's testimony that Energy Advisers apply the Peaker Credit inconsistently and that appeared in the transcript at -- on October 26th at page 1500, lines 10 to 12.

MR. ADELBERG: I do.

Q.34 - And -- page 1501, lines 10 to 12. What comments do you have in response to that observation by Dr. Rosenberg?

MR. ADELBERG: First of all, I would want to point out that I think that we were under the same misconception as perhaps one or two of the other parties in this case at the outset of these proceedings.

We had -- we had understood, and we now realize incorrectly, that the 40/60 methodology, 40/60 split that the Board had adopted in 1992 was intended to be an application of the Peaker Credit Method. We now stand corrected on that and hopefully we can address other issues that that change implies as we go through the remainder of the hearings.

But putting aside that issue for the moment, we understood Dr. Rosenberg's criticism of our approach to be this, that the Peaker Credit Method, which we purported to be applying, should be applied to the costs of plants. Because that is what you do, you take -- you look at the costs, for example, of a coal plant and you look at the portion of capital investment in that plant that would match the capital investment of a peaking plant. And you allocate that much to demand and the rest -- anything in excess of that to energy.

Now his criticism was that with respect to the Genco costs, instead of looking at the actual costs of the power plants that Genco is operating and charging Disco for, we looked at the PPA, the Genco purchase power agreement as the -- to set the parameters of the cost on which we then applied the Peaker Credit Methodology.

And I guess my response to this is that while we understand his criticism, first of all, as I think Mr. Morrison brought out in cross examination over the last day or two, that to some extent it is important to look to the PPAs to define the overall amount of costs because they are the actual costs that Disco has billed. They are the costs on which the revenue requirements are based. So to the extent that PPA costs differ from the cost of the underlying generation, if you use the underlying generation, you are going to be allocating costs that differ to some measure -- in some measure from the revenue requirements. So that was one reason we thought the PPA costs should be looked to.

The second is in the case of the Genco PPA, it turns out, at least as we understand it from the company's -- from Disco's response to interrogatories, that the billing structure of the PPA tracks the accounting costs fairly closely. It was designed, in effect, to track the accounting costs in such a way that the costs that they are seeing billed under the PPA are not all that different than they would have seen if they had continued to be an integrated company and were looking at their books in terms of what costs they would experience.

So -- and in effect, as we understand it, the only real difference is were some minor different timing

differences in when some of the costs are being recovered.
But fundamentally they were billing as fixed costs what would have looked like capital costs on the books of the company if it was still an integrated utility.
So we felt that the level of fixed costs that were billed as fixed costs by Genco were a suitable proxy for the fixed generation costs that one would normally allocate using the Peaker Credit Method.
So I hope that answers or at least addresses that criticism and I think if one were to conclude that it should be done the way Dr. Rosenberg suggests, I think the difference and because the PPA costs and the accounting costs are almost the same that the difference in outcome would probably be very very small. But that was our reasoning.
Q.35 - Thank you. And again, Mr. Adelberg, do you recall Dr. Rosenberg's testimony on October 26th 2005 at page 1511, lines 12 to 14, when he testified that Energy Advisers disparaged embedded costs as a "futile exercise". What comments do you have in respect to that?
MR. ADELBERG: I certainly can understand how one might get that impression from our description of -- and particularly some of the quotes about the limitations of embedded costs or fully allocating embedded cost

methodologies, in particular a couple of quotes that we took from the Bonbright treatise, but to be clear, we tried to make -- we tried to say in our testimony -- and I think you will find statements to this effect -- that embedded costs methodology is a longstanding methodology. If one understands its limitations, it can -- it can be a useful tool.

We think for looking at equity of the rate structure. And when I say equity, I'm thinking of equity in the sense of if you have a certain number of parties that are using a common asset, you can say there is some element of fairness if they pay some proportion of the cost of that asset for their use of the asset. That corresponds to how much burden they put on the asset or how much of the asset they seem to be using.

What we were trying to make clear was that that is a very different analysis than an analysis of cross-subsidies as the term cross-subsidies is commonly understood in the English language, we think, and certainly is universally understood in economics. Cross-subsidies in most people's mind means that if I am cross-subsidizing you, I am paying some costs that you are causing. And vice-versa, if you are cross-subsidizing me, you are paying some costs that I am causing.

Well since a fully allocated cost study cannot causally attribute joint and common costs, it is just impossible for a fully allocated cost study to tell you whether there really is a cross-subsidy in your rate structure.

So I think one reaction might be well, we rally don't care about cross-subsidies. What we care about is equity and we have done it this way for a long time and therefore will continue to do it this way. I think you probably should care about cross-subsidies, particularly because as you -- as the world moves more towards competition, cross-subsidies become unsustainable. You simply cannot have regulated prices that have cross-subsidies in them because any party that is being required to pay a cross-subsidy will simply be stolen by a competitive firm that can provide that service without having to bear the burden of that cross-subsidy.

So limiting cross-subsidies is as important long-term goal as you move towards more competition. It's one that perhaps you might want to think about as you decide what the role of revenue cost ratios is in this proceeding.

And fortunately there are -- as we say, there are -- in our testimony, there are relatively accepted techniques for truly measuring whether cross-subsidies exist.

CHAIRMAN: Mr. MacNutt, I know you are getting close to the end of your examination but I think we will take a 10 minute recess now.
MR. MACNUTT: So Mr. Garwood will remain on the line.
CHAIRMAN: Yes. He will stay on the line. We will see you when we get back in, Mr. Garwood. Too bad you weren't here on the banks of the St. John.
MR. GARWOOD: My recovery bed is so much better.
CHAIRMAN: Yes, I'm sure. We'll be back in 10 minutes.
MR. GARWOOD: Thank you.
(Recess)
CHAIRMAN: Go ahead, Mr. MacNutt.
Q.36 - Thank you, Mr. Chairman. Mr. Adelberg, do you recall --
CHAIRMAN: Is Mr. Garwood still with us?
MR. GARWOOD: He is.
CHAIRMAN: Good. All right. Carry on.
Q.37 - Thank you. Mr. Adelberg, do you recall Dr. Rosenberg's testimony on October 26th 2005, at page 1514, lines 2 to 6, when he said in commenting on the appropriateness of using marginal costs in rate design he suggested that Dr. Alfred Kahn stated in his textbook that firms in competitive markets often set their prices based on fully allocated costs.

MR. ADELBERG: I think the statement that Dr. Rosenberg made was that Dr. Kahn acknowledged that firms in unregulated markets often price their services -- firms that have high fixed costs often priced their services at what he called full costs. And this was in the context of Dr. Rosenberg's explanation of reasons why he did not endorse the marginal cost approach.

And while I think Dr. Rosenberg accurately quoted Dr. Kahn, I think it's very possible to misunderstand what that quote was actually saying, and I was very concerned that the record -- there might be an impression from the record that somehow when Dr. Kahn talked about full costs that that had some relationship to fully allocated costs, and if you read Dr. Kahn's text, I think nothing could be clearer than Dr. Kahn does not endorse embedded costs as an economic basis for pricing under any circumstances. What he was saying was that firms with high fixed costs -- he was saying two things. One is that they -- that while shortrun marginal costs which is sort of the theoretical ideal of competition, well those vary -- can vary from time to time, day to day, month to month, whatever, depending upon the business you are in, but firms often don't find it practical to change their prices that frequently. So they might engage in some kind of averaging approach. That was the first thing he was saying.

And secondly he was saying if they are in an industry, for example airlines, which is an industry where Dr. Kahn was particularly familiar because he was Chairman of the Civil Aeronautics Board in the 1970s when it deregulated -- if they have high fixed costs and they try to price close to their variable costs, they can end up not covering their total cost. So they often have to mark up their prices in some fashion to cover their total costs.

I think if you read the text, what Dr. Kahn goes on to say was that longrun incremental costs might be closer to what firms in that situation might strive for, although there are reasons why they might vary how much they mark up above their marginal cost.

But I certainly don't want to suggest that this was Dr. Rosenberg's intent, but to the extent that his reference to full cost might have been misinterpreted I thought it was useful to just clarify that point.

Q.38 - Thank you. Now Mr. Garwood, have you had an opportunity to review the transcripts of Dr. Rosenberg's direct and cross examination on October 26th and 27?

MR. GARWOOD: I haven't reviewed the transcripts, but I was present.

Q.39 - Well in the circumstances perhaps it is not necessary that you have done so.

MR. GARWOOD: Right.

Q.40 - Would you just give us -- Dr. Rosenberg stated that he was uncertain whether Maine had based its rate design on marginal cost analysis, and he made that comment on October 26th at page 1512 at lines 13 to 14. And I begin -- having given you that background, what is your experience with the Maine regulatory system?

MR. GARWOOD: In -- I came into the rate department of Central Maine Power Company in the late '80s. But in the early to mid '80s the Maine Commission had a heightened interest in looking at both embedded cost of service studies and marginal cost of service studies for purposes of believing that there were benefits -- economic benefits to somehow reflecting proper price signals which marginal cost studies might lend themselves towards better than the embedded study approach. And so throughout the early and mid '80s, the Commission required that the companies file both embedded and marginal studies.

In the late '80s, in 1989 and throughout the early '90s, the company had a series of revenue requirement and rate design cases. And at the conclusion of one that started in '89 the Commission -- the Maine Commission stated that it no longer wanted to rely on the use of an embedded cost of service study for purposes of rate design and that it would look solely to marginal cost of service studies for purpose of rate design.

And so after that case, I believe it was docket number 89/68, the Maine Commission, the Central Maine Power Company and I also believe Bangor Hydro was under the same rules, but I could be wrong there, was no longer required to file embedded cost of service studies in conjunction with its rate design cases, and the Commission relied solely on marginal cost of service studies for that purpose for those cases that occurred after that.

Q.41 - Thank you. Now, Mr. Adelberg, i am going to turn to the evidence of Mr. Knecht. With respect to exhibit PI-1, the direct evidence of Mr. Knecht, his live direct examination, his cross examination, do you have any comments you wish to make?

MR. ADELBERG: I think we -- as I have already mentioned, we have many points of agreements with Mr. Knecht. I think as I have said, his market approximation approach is very, very similar in concept and in application to what we see a marginal cost approach would mean for Disco.

I think that one very minor area where I'm not sure whether we disagree but I'm also not sure whether we totally agree -- it was a point that came out this morning.

Mr. Knecht stated that his -- it sounded like his preference to the extent a market approximation approach was used would be to look essentially one year forward and base the rates on the expected market costs over that period.

In our experience, regulators that have used marginal cost studies have very commonly looked beyond a year, and for the reason that customers are making -- often making decisions that have impacts that are going to go on for several years, and if you give them a short term price signal perhaps they will miss -- they will make an investment in a furnace or a dishwasher or they will make a decision not do something that they will regret when prices change two or three years down the road.

So admittedly the farther out you go in time the less certain your forecasts are. But in most areas of human endeavour where we make longterm investment decisions we try to think ahead, we try to think -- if we are planning on having a family we buy a house that is going to have bedrooms to accommodate our kids, and if we are going to buy a car we think about -- and we are going to keep it for a few years we think about how we are going to use it over a few years.

Electricity, it's -- how much information you can pack into a price signal is certainly limited because your rate structure tends to be fairly simple, particularly for the residential customer.

However, if you are looking at in time and you are seeing some expectation of rising costs more than a year out -- and a common example would be where you see that, you know, your capacity long now in the sense you have more than enough capacity for the shortterm but you might need more in the longer term, that's the kind of information you would look at in a marginal cost study.

In our opinion you would want to have that information before you when you design rates and at least give careful thought to the extent to which it would be helpful to reflect that kind of information in your price structure.

So that would be a subtle difference between our view of the value of -- of how marginal cost information can be used.

But apart from that I think we had many, many areas of agreement. We addressed -- his views on phasing out the declining block were not much different from ours. We suggested in one of our interrogatory responses how the Board might temper one of his proposals if it felt that he had gone too far. But in fairness to him, he acknowledged that his proposal was aggressive and he himself offered his own alternative to that proposal. So as I say, I think we are very much on common wavelength on many points.

Q.42 - Thank you. And now I guess would be the final question and with respect to Mr. Knecht, I address this to you, Mr. Garwood.

In response to questioning by Mr. MacDougall on October 31, 2005, Mr. Knecht testified that he had concerns about Dr. Rosenberg's modelling of the Coleson Cove plant in his embedded cost study. Can you comment on how the environmental and fuel conversion cost of Coleson Cove should be modelled in an embedded cost analysis?

MR. GARWOOD: Well in the context of this case I'm not sure I see the concern over those additional costs. Whether we accept the Board's 40/60 split as predetermined that was to apply to a plant's costs, full costs or whether we were to use the Peaker Credit Approach, and derive some new demand and energy split using that analysis, I don't see the reason why you would view these costs any different than another category of costs out of this plant.

I believe it is the case, subject to check, that the costs -- before the costs at issue are taken into account, if you were to use the Peaker Credit Approach, the plant

costs in total already exceed the cost of a peaker and so anything above that cost would be allocated to -- or classified as energy related.
And so simply any additional costs you placed on the plant, be it these costs at issue or other costs, would end up being classified as energy. And likewise, if you simply go back and use the Board approved 40/60 split, I am not aware of any -- of any issues surrounding the decision the Board had when it came to that decision for treating certain costs differently than others. So from my perspective, in the context of this case, whether it be a Peaker Credit Approach or simply using the pre-approved 40/60 split, I would not see treating these costs differently than simply adding them on to the total cost of the plant and applying the demand energy split.
MR. ADELBERG: If I might just be permitted to add one small amplification to that. In our view, the situation is not all that different from one where you have a cost overrun. In the sense that, as we understand it, the Coleson Cove enhancements and additional capital investments were made in large part in expectation of taking advantage of an economic fuel source which obviously hasn't materialized. And so you would say, well now they have made investments to get an energy savings that is not being -- that is not

occurring, what do you do with those additional costs.

Well in an embedded cost methodology, and in particular under the Peaker Credit Method, the ratepayers basically have -- traditionally have borne the risks to a large extent of cost overruns of power plants and they have also reaped the benefits of plants that prove to be more economic than expected or which had longer lives than might have originally been anticipated and therefore, continued to provide benefits beyond the end of their accounting lives.

Heavily depreciated hydro facilities are an obvious example. Under an embedded cost study, ratepayers typically will get the low cost energy out of a hydro facility and once the capital costs have been fully amortized, and paid off in rates, the ratepayers aren't charged any more for them.

So to that extent, the Peaker Credit Method works to their benefit. If you have a cost such as Coleson Cove that might have been more than you figured in when you did your original economic analysis of the desirability of making that investment, those are costs that the ratepayer bears and under the Peaker Credit Method, they are simply -- they are allocated to energy even though the energy savings haven't been produced.

There is sort of a -- there is sort of a symmetry to the gains and losses to ratepayers. But we would think they would still be appropriately allocated to energy under a Peaker Credit Method.

Q.43 - Thank you. Now that's the end of questions with respect to comments in respect of either witnesses and now I would like both Mr. Adelberg and Mr. Garwood to provide us a brief summary of your evidence in this, keeping in mind the time of day.

MR. ADELBERG: Well because my responses thus far have been so concise, it will surprise you to know that I have actually anticipated most of the points in my testimony, so I will just touch on them very quickly.

The testimony covers -- initially we addressed the role of revenue cost ratios and I have already talked about our views on that, the value of embedded cost -- revenue cost ratios and how they may be distinguished from an economic cross-subsidy analysis.

We then talk about generation costs. We have already talked about the fact that we applied the Peaker Credit Analysis to the Genco fixed costs. That is a major area of difference between us and Disco. However, it is an area in which we are very much on similar footing with the other Intervenor witnesses.

And our position of third party credits, again we are very much aligned with Dr. Rosenberg and have a somewhat different view than the company in the sense that we believe those credits should reflect the nature of the underlying sales that generated the revenue.

So if it was a sale of capacity, then the credits should be used against capacity costs. If it was a sale of energy, likewise, it should be a credit to energy costs.

On the area and issue of transmission, I'm sure we will hear more about, but I know it has already come up in this case, that we do stand alone in that we believe the proper method and the one most consistent with cost causation is to allocate transmission costs on the basis of coincident peak demand. And but we have acknowledged that this will probably to do this is probably going to require a change in policy on the transmission pricing as well in the province so it may be a step that has to be postponed and done in conjunction with that.

On distribution cost allocation, we reviewed the methodologies and the data presented by the company, by Disco. We noted some areas where the data seemed to be a little but weak, but all in all, we thought their analysis was within reasonable bounds.

Marginal costs is the next topic we focused on our testimony. I have already given, I think, a fair sense of our overall views on why marginal costs could be helpful. And then finally, rate structure, we have touched on some of these areas. We think that the areas to look to if the company is to move towards a rate structure that has less discrimination and has more -- more alignment of costs to usage of power, would be in addition to the elimination of a declining block and the merging of the GS I and II classes, which are points that everybody seems to agree on, we think the areas that could be most productively explored would be voltage differentiated rates, as we talked about just early this afternoon, and seasonality because we think that there -- appears to us that there are significant differences in seasonal costs of energy even if there are no capacity needs in the short -- next several years for Disco.

So that basically is an overview of the major points in our testimony.

MR. MACNUTT: Thank you. The panel is now available for cross examination, Mr. Chairman. The panel comprised of Mr. --

CHAIRMAN: Yes, tomorrow morning. We will adjourn now until tomorrow morning at 9:15.

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

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