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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INDEX

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CHAIRMAN: Good morning, ladies and gentlemen. Do we have any preliminary matters?

MR. MORRISON: No, Mr. Chairman.

CHAIRMAN: Good. Then go ahead, Mr. Morrison.

MR. MORRISON: Thank you.

MR. ADELBERG: Do we have Mr. Garwood?

MR. GARWOOD: Yes, we do.

MR. MORRISON: Good morning, Mr. Garwood. -

2202 - Cross by Mr. Morrison -

MR. GARWOOD: Good morning.

MR. MORRISON: Good morning, Mr. Adelberg.

MR. ADELBERG: Good morning.

Q.579 - I would like to just direct you to something you said on Tuesday with respect to seasonal rates. And I think you said that -- and you were referring to the evidence of Mr. Marois. And you said that the reason Disco did not endorse seasonal rates was due to the complexity. And then you went on to say that there would only be two rate changes a year, so it shouldn't be too complex a matter. Am I paraphrasing your evidence correctly?

MR. ADELBERG: That's correct.

Q.580 - I am going to read you a passage from Mr. Marois' evidence just so that we are clear about what we mean by complexity, Mr. Adelberg. Mr. Marois said, and it is September 28 transcript, page 1127, and he said, an it is Mr. Marois, "Well by complexity, if you are talking about a seasonal rate, you are at least talking about two rates for the year. And with typical residential customers, I mean, I think each time you add another level of complexity to the rates it is not viewed as being something positive. So that is what I mean, it adds elements to the rates that the customers need to understand."

So would you agree with me, Mr. Adelberg, that what Mr. Marois was talking about when he was referring to complexity, it was complexity from the customer's perspective?
MR. ADELBERG: Yes, indeed.
Q.581 - Okay. Now I would ask you to refer to PUB-1, which is your evidence. And perhaps at this point, Mr. Chairman, I will also be referring to exhibit A-3, the evidence of Neil Larlee.
Actually I think my questions are more directed at you, Mr. Garwood. At least I think they are.
MR. GARWOOD: All right.
Q.582 - If you could turn to page 72 of your evidence.
MR. GARWOOD: I have it.
Q.583 - And that is table 6, I think, reflecting voltage -- revenue to cost ratios for your proposed voltage differentiation. Is that correct?
MR. GARWOOD: That is correct. And we may have submitted a corrected version of this.
Q.584 - At the outset, yes. Mr. Adelberg did make some corrections to the numbers on the table.
MR. GARWOOD: Okay. Right, yes.
Q.585 - Now on Tuesday, Mr. Garwood, you took us through a series of steps that you used in order to develop the

revenue cost ratios split to by voltage level. Is that correct?

MR. GARWOOD: That is correct.

Q.586 - And you did that primarily for the general service class, correct?

MR. GARWOOD: Right.

Q.587 - And when you look at those revenue to cost ratios -- and I am going to say that the revenue to cost ratios for the general service class look a little funny to us. And --

MR. GARWOOD: As they did to us as well.

Q.588 - Okay. You thought they looked a little --

MR. GARWOOD: Yes, when I put these together I said, looks funny, doesn't look right. Something must be problematic with the data, but -- which really just led us to conclude that you couldn't conclude here that you had enough information to create seperate sub-classes at this time with the infromation in this cost of service study. But it sure, in our opinion, begged for further examination and determine what of the data is causing the results we see.

Q.589 - I think specifically, Mr. Garwood, you probably didn't have any revenue data, is that correct, for primary and the customers for both GS I and GS II? -

2205 - Cross by Mr. Morrison -

MR. GARWOOD: Let me --

Q.590 - Well perhaps you can look at, Mr. Garwood --

MR. GARWOOD: I could look at -- it would be quicker if I could look at that and get back to you later this morning.

Q.591 - Okay. I understand from your evidence that you took your information from Mr. Larlee's schedule 6.0, which was attached to his cost of service study, correct?

MR. GARWOOD: My information from 6.0, I took the information I used to construct this from the entirety of the cost of service study.

Q.592 - Okay.

MR. GARWOOD: Not just a specific schedule. I think I ended up modifying maybe ten of the individual worksheets that comprised that CCAS.

Q.593 - Okay. And you wouldn't disagree with me, Mr. Garwood, subject to check, that Disco didn't provide any revenue information with respectto the GS I and GS II customers primary, right?

MR. GARWOOD: Yes, subject to check, I will go ahead and accept that which would skew the RC ratios certainly. Again, as I think I said yesterday, it has been my experience anyway, that it is more common than not you would have different cost of service for primary versus secondary customers and more customary therefore to have seperate sub-rate classes for those types of customers.

Q.594 - Right. You would have had to assume some variables in your analysys, correct?

MR. GARWOOD: Yes, I think yesterday, as I have stated and as I had reviewed what I had done to produce this itemized list that I had for my own reference for what I changed, there were tow that stood out to me where I had to make such assumptions. And one I wouldn't even call an assumption. It was just there was a -- 1.4, I believe which determines customer allocation factors and weighted customer allocation factors, number of customers is necessary to know. And the study as was presented only gae total number of GS I or GS II customers and total secondary customers. So I assumed the difference was primary.

And then later I had to make an assumption about what the 12 NCP for the sub-classes would be given that schedule 1.3 only gave that level of detail for -- I'm sorry, it gave the single NCP number for the primary and secondary as well as the total GS I and GS II classes. But it didn't give for primary and secondary a 12 -- an average 12 NCP number.

And so I took a leap of faith and said that if primary was -- and I forgwet the number, I will just throw it out -- if primary was 40 percent of the single NCP number, they very well would likely be 40 percent of the average, 12 monthly average NCP numbers.

So that is obviously an assumption.

Q.595 - Right. And you would have had to make some assumptions with respect to revenue, right?

MR. GARWOOD: Yes, on the -- well on the revenue side, yes, you are right, where the miscellaneous revenue worksheet is, which spread miscellaneous revenue back to the classes, that starts out with using customer allocation factors and then adds that back to toal revenues. And once you allocates the misclleaneuos revenues, anyaway. So I had to create additional rows to accomodate primary and secondary on that worksheet as well and use the same underlying basis for allocating miscelaneous revenues for the sub-classes as was done for the classes that were already shown on that schedule.

Q.596 - Okay. Thank you, Mr. Garwood. Mr. Adelberg, we spoke a little bit about seasonal rates yesterday. And as I understand your recommendations, you are proposing that the general service class be differentiated by voltage level, correct?

MR. ADELBERG: Correct.

Q.597 - And you did speak, although your evidence doesn't delve into seasonal rates in any great detail, I think you mentioned yesterday that you would recommend moving to some type of seasonal rate structure as well. Is that correct?

MR. ADELBERG: That is correct.

Q.598 - And I just want to put this to you, Mr. Adelberg. Do you think it makes sense for Disco to essentially eliminate the GS II or the all electric class first before moving into looking at stratifying the class by voltage level and introducing seasonal rates?

MR. ADELBERG: That is a tough question that there is obviously no scientific way of judging how many changes you want to make at any given time. I certainly -- I understand the company's desire to approach rate changes in a sort of serial fashion, not to compound too many things, and that is not an unreasonable concern.

We have this problem that the company is facing, as has been raised in this proceeding, is that it is -- it has been a slow process of dealing with the historic anomolies in the rates and there is some concern among some of the parties represented here that the pace that the suggested changes in this application were also timid. And if we continued at that pace, we could be years and years from getting to where we want to go.

So seasonality will help on one of the issues where seasonality is a change that would probably improve the kind of price signals in the same way that marginal costs would, or a very similar way. It is going to -- marginal costs are probably going to suggest higher seasonal costs. Even if you do it on an average costs basis, you may well get a similar effect.

And I guess it's -- you have to kind of look at that in the context of the overall changes that are going to be made at the end of the case. It is sort of hard to pick one out and say --

Q.599 - Certainly -- certainly you would agree that gradualism is a consideration.

MR. GARWOOD: We have been very solidly behind that concept from the beginning. There is often a gulf of difference between the ideal and the practical. No question of that.

Q.600 - Would you also agree that if -- it would make the analysis of the issue of voltage differentiation easier if it was first turned into a homogeneous class?

MR. ADELBERG: Yes, I'm not sure how much additional complexity it adds but certianly the fewer steps that you have -- I mean, one of the things about seasonal rates that -- from a customer point of view is maybe makes them easier to sell than changing the block structure, for example, is that you can tell customers, we are giving you a rate decrease six months of the year or eight months of the year. And we are giving you an offsetting increase four or five months of the year. So the customer can see it as a trade-off immedately and they don't -- it's not as supicious looking to the customer as one where they simply see a block structure --

Q.601 - Do you have a background in public relations as well, Mr. Adelberg?

MR. ADELBERG: Well we -- I have a background in changing rates and seeing customer reaction. We had -- when we went through our first major rate structure change, very close in time to your last CARD -- or the last CARD decision here, we had problems with our residential rate as well. And we tried to go make an 8 percent change to set the signal for the residential class closer to what we thought the marginal costs were. And we had public uproar. We had people calling for mass meetings and protests.

So we are very painfully aware of how sensitive these things can be. People have expectations. So it is very imporatant to eduate people and bring them along and make sure they understand what they are -- what you are doing and that you are not taking -- that you are shifting but you are not -- this isn't simply a ploy to benefit the company. That's -- no question about it.

MR. MORRISON: I have no further questions, Mr. Chairman.

MR. GARWOOD: I can elaborate or clarify a little bit on the revenue. I have looked at the cost of service study that I had used. If you would like me to do so now and take care of that issue.

Q.602 - Certainly, Mr. Garwood, yes.

MR. GARWOOD: I had the total revenues for the GS I and the GS II classes each and I spread the total revenues back to my sub-classes primary and secondary based on the ration of customers in each sub-class for the total.

Q.603 - That is what we assumed you probably had done.

MR. GARWOOD: Yes. That's what I did. So it's not the fact that I was missing total revenues, I had total revenues. I just made an assumption about how they were allocated amongst the sub-classes.

MR. MORRISON: Thank you, Mr. Garwood. Thank you, Mr. Chairman.

CHAIRMAN: Thank you, Mr. Morrison. I was lulled into not doing the appearances for the sake of the record. So I will get that in here now. Mr. Morrison, I don't think there is any reason for you to move back a row or anything else so you can settle in there for the rest of the

morning, if you would like.
MR. MORRISON: Thank you.
CHAIRMAN: Of course, you are appearing on behalf of the Applicant NB Distribution Customer Service Corporation. And who else is with you, this morning?
MR. MORRISON: Consultant Mac Ketchum and Neil Larlee.
Q.604 - And Formal Intervenors Canadian Manufacturers and Exporters New Brunswick Division is not represented today. Nor is Eastern Wind.
And Mr. MacDougall is here for Enbridge Gas New Brunswick. Anybody else with you, Mr. MacDougall?
MR. MACDOUGALL: Not today, Mr. Chair. Thank you.
CHAIRMAN: Thank you, sir. For the Irving Group of Companies?
MR. BOOKER: Mr. Chair, Andrew Booker.
CHAIRMAN: All right. And Mr. Andrew Booker here as representing the Irving Group. Jolly Farmer is not here. And Rogers Cable is represented today.
MS. VAILLANCOURT: Christiane Vaillancourt representing Rogers Cable, Mr. Chair.
CHAIRMAN: Thank you, Ms. Vaillancourt.
Q.605 - Self-represented individuals? Municipal Utilities?
MR. GORMAN: Good morning, Mr. Chairman. Raymond Gorman for the Municipal Utilities. This morning I have Dan Dionne

from Perth Andover and Dana Young and Jeff Garrett from Saint John Energy.

CHAIRMAN: Thank you, Mr. Gorman. Vibrant Communities is not represented here today. Public Intervenor?

MR. HYSLOP: Good morning, Mr. Chair. Peter Hyslop and Ms. Power for the Public Intervenor.

CHAIRMAN: Thank you, Mr. Hyslop. No Informal Intervenors in the room that I recognize anyhow. Mr. MacNutt, who do you have with you today?

MR. MACNUTT: I have wiht me Doug Goss, Senior Advisor, John Lawton, Advisor, John Murphy, Consultant, Arthur Adelberd, Consultant and on the telephone Steve Garwood, as we have noted.

CHAIRMAN: Good. Thank you, Mr. MacNutt. And I was wondering if the panel has some questions of the witnesses.

<u>BY THE BOARD</u>:

DR. SOLLOWS: Rather disingenuous of you, Chairman, of course I have some questions.

CHAIRMAN: Hope springs eternal.

DR. SOLLOWS: Thank you. I am not directing these questions at either you or Mr. Garwood particularly so feel free, either of you, to answer as you see fit.

First question I have I know we saw in Dr. Rosenberg's evidence and the evidence on load research, that a lot of the cost allocation proposals seem to focus on January loads. Now I am wondering if you have had a chance to look atthe load forecast evidence that we have and we haven't dealt with yet. My problem there is, I find that the maximum demand is substantially higher in February than it is in January, 150 megawatts higher roughly. And basically there is a much lower load facotor apparently in February than in January.

And I am wondering what impact that might have in all of this discussion we have had about cost allocation based on January loads, when in fact it is in February?

MR. ADELBERG: Steve, do you want to pickthat one up?

MR. GARWOOD: Well I would first like to start out by saying I had not reviewed the load forecast I think being giventhe indication that we weren't going to be involved in that aspect of the case. I guess that is a preface. It seems to me that to the extent your load forecast is going to show information that differs from the information put forth so far in this cost of service study, this cost of service study before a decision is made on rate design should be updated to reflect the forecast to the extent the forecast is deemed accurate.

Not knowing the magnitude of the differneces in -- proportionally among the rate classes, it is hard for me to say whether there is a big impact to how costs would be allocated on a -- those costs that are allocated on a demand allocator basis.

If simply the month changes, but say for instance the proportions among classes of the peak demand doesn't change, I don't know, Arthur, do you want to add anyhting to that?

MR. ADELBERG: No. I mean, that is really the question. It is not necessarily the fact that there is an increase in overall demand. It would be -- the question would be the relative contributions of the class and that would -- that would be the --

DR. SOLLOWS: So that is something you will have to look at in the load forecast portion of the hearing?

MR. ADELBERG: Yes. And I would agree with Steve, I would think it would be relatively easy to incorporate that kind -- any new information on that into the final cost of service that is the basis of rates in this proceeding.

DR. SOLLOWS: Thank you. Next question deals with, I think it was a discussion between you, Mr. Adelberg, and I am not sure whether it was Mr. Morrison or who was asking you.

But you made reference to both bid based and merit order dispatch. And I wonder if you could clarify what that was about.

MR. ADELBERG: Certainly. In my experience, which was originally mostly in the Northeastern United States, although I have done consulting work elsewhere, in the Northeast was a what is called a tight pool in the sense that well before the federal government instituted a requirement for independant system operators and centralized market control in the regions, New England had agreed to do that voluntarily. It was basically as a result of the blackout back in the 1960s that they institued a centrally controlled dispatching grid. And also to get economic benefits.

And when it was instituted and the way it operated until the late 90s was that each utility since -- until the 80s, all the utilities owned the power plants and then even after the 80s, other plants only operated under contract to the utilities.

So the utilities would have to submit their runing costs for each of their plants to the system operator on a regula basis, on a fairly constant basis. And the system operator would actually redispatch the whole portfolio of plants in the region -- I can't remeber, was it every five minutes or Steve, do you recall what the frequency was for dispatch under the old --

MR. GARWOOD: The five minutes sounds familiar but I -- you know, whether it was different.

MR. ADELBERG: Anyway, it was quite frequent.

MR. GARWOOD: Absolutely, yes.

MR. ADELBERG: The would -- optimize the system to achieve the lowest total running costs. So that meant that the plants with the very lowest costs would be dispatched first and then you would work your way up the order, as I say, the merit order, to higher and higher costs until you met all the load.

Now within that -- within that construct, there were always exceptions. One exception was there were times when you have to run a plant what they say out of merit, even though it is not the least cost plant because it is necessary for reliability, to maintain voltage in a particular region.

And then as -- when PURPA, the Public Utility Regulatory Policies Act came into effect and utilities started having to contrct for power, most of those contracts were must run. And that was intentional policy on the part of the government to give the developers of those projects and assured revenue stream. And they essentially exempted them from the dispatcher requirements that utilities had.

And that resulted in a -- in our case, a rather significant part of our portfolio was not economically dispatched anymore. In fact, it reached -- a maximum of 40 percent of our energy was coming out of those contracts at that -- at the peak of that experience.

When the markets were restructured starting in the late 1990s in order to foster competition, it was felt that it would be preferable to have -- rather than have the owners of plants submit cost information, the owners of the plants would actually bid what the price at which they would be willing to operate their plants. And the opeator would basically again choose from the lowest cost bids until the -- until they got to a price that would meet all the damand.

And then all of the plants essentially were paid atthe so-called market clearing price, the price that was necessary to meet all the demands. So that if you wanted -- you could, as the owner of a plant, if you wanted to, you could bid your plant in at zero cost. Just say I will take a price -- I will take any price you will give me. And a lot of plants did that and plants that had no choice, like nuclear plants essentially did that as well.

And so the economics depended on the individual willingness of generating owners to bid their plants and you know, their -- the operation of their palnt into the marketplace.

But again you have -- the extent you may have and I understand you do have in New Brunswick, you are going to have exceptions to that under either system. To the extent you have must run contracts, they are going to override either that -- under either model they are going to overrride the dispatch of plants, whether it is on the basis of costs or on the besis of bids. If you have must run, by definition they run regardless of what else happens.

MR. SOLLOWS: And in reference to that there are two types of must run plants, if I understand the evidence correctly, those that must run because of essentially a policy decision that we want to promote combined heat and power plants. And then there is the notion that, as you said, that you might have a must run designation for voltage support.

Should we be able to find somewhere in the evidence some documentation or study that clearly establishes the need to run a plant for voltage support?

The difficulty I'm having is having sat through a transmission OATT hearing and such, I heard over and over again that our ring transmission system is very robust and has substantial -- I don't think anybody likes the word "excess capacity" -- but it is robust, okay.

And that leads me to wonder why we would be running -- designating a plant must run if we have a very robust transmission system?

MR. ADELBERG: I think probably this may well be one of the areas where the unbundling of the utility, the restructuring of the utility, introduces a new challenge for you. Because under the old integrated model that information was readily at hand to the applicant. Here we have -- now obviously we have crossed that bridge to some extent.

The applicant has been able to -- I'm not sure what your process was. But one way or another we have received information from Genco.

But I'm -- I would -- Disco of course negotiates rates under the PPA every year. So in the process of doing so presumably they have -- and under the PPA they have the right to see information about Genco's operations I believe. Although you might want to address that to them, but –

MR. SOLLOWS: How in your experience would a must run designation arise in this way? I mean, would it not be the System Operator that would make the designation?

MR. ADELBERG: Well, again it would be -- it depends a little bit on the history. In some cases where the -- to the extent -- in New England for example before the restructuring of the market, the utilities -- and while there was a System Operator the utilities were heavily involved in advising a System Operator. And they had committees that set the policies for it.

So a lot of the information would come through the utilities to the System Operator. As the System Operator has been strengthened, the System Operator has more of its own resources and staff that can -- it can and do make those kinds of decisions.

Steve, do you have any --

MR. GARWOOD: We have -- first of all there was an Interrogatory, and I don't recall the number, where I think it was Courtenay Bay was -- it was questioned about Courtenay Bay's must run status.

And the company provided a response, as I recall, that in fact it had been placed in a must run status historically but wasn't able to provide the specific number of times or when that occurred.

And as I do recall it was for voltage support or reactive power requirements. So there is some evidence in the case through that Interrogatory. There may be others but I don't recall where this topic came up.

In New England, as Mr. Adelberg just said, that is the case. And New England is also set up with -- via satellite dispatch centres who are the contract to assist the System Operator with these types of issues where must run staff to the plant is a more local requirement than say a regional need. And it could be for voltage support or simply honoring transmission constraints.

For instance just quite the reverse actually, a situation I will call is the interface between Maine and the rest of New England has been constrained historically considerable. And there is excess generation in the state of Maine as a result of that.

And units are actually -- units that would otherwise be more economic to operate have been dispatched off as a result of that, causing distortions in the -- what would otherwise be the economic merit order of dispatch.

So my experience is that these are more local area reasons that units are put in a must run designation or a dispatched off designation due to local area constraints or voltage concerns.

MR. SOLLOWS: Thank you. Now the New Brunswick -- we have heard a lot about marginal cost analysis and that sort of thing.

The NBSO publishes final hour marginal costs which I understand are bids from -- essentially from Genco to operate their various generation units in the province. Is my understanding correct?

MR. ADELBERG: That is one -- Steve, I don't know if you know the answer to that.

MR. GARWOOD: You say bids. You know, I don't know how much they are reflecting of bids versus cost. I did see evidence that suggested marginal fuel costs in some of the evidence, maybe in Enbridge 37 or 38 seems to come to mind, where there was marginal fuel cost, hourly marginal fuel cost provided. So that type of information is obviously produced by Genco or the System Operator.

MR. SOLLOWS: Okay. So whether they are bids or not, I think we can clarify from the record of the SO.

MR. GARWOOD: Right. And again as I read the record, that is solely their fuel cost as opposed to, you know, total marginal cost.

MR. SOLLOWS: Okay. I guess perhaps my understanding is a little different. Because I have sat through some System Operator hearings. And that may be what is confusing me here. But I think I can get what I need from the record of those hearings.

I guess the question is whether they are fuel or short run marginal costs or bids, or whatever they are, in general how should we or should we use them to inform our rate design process?

MR. GARWOOD: Well, it seems to me that those marginal costs, be it that they may only be fuel, to the extent they still show a seasonal variation or an on-peak, off-peak variation -- which I believe they did.

It seems to me that Mr. Adelberg and I, in reviewing the marginal cost information that came out of one of those two IRs I just mentioned -- one of them is marginal I think and one of them is average -- showed something like a 21.4 percent seasonal differentiation, assuming that the winter months was November, January, February and March, and the nonwinter season being the other months of the year.

There was a 20 -- you know, over a 20 percent differential in those if I recall correctly our analysis. Arthur, you may correct me on that if I'm off.

So to me, even without doing a full-blown marginal cost study, as we have talked about and as I provided in response to an Interrogatory, you still have some information there that, at least in the opinions of myself and Mr. Adelberg, shows that you could take that and give consideration to how you would reflect seasonal differentiation in your customer rates.

MR. ADELBERG: And that is a very short-term focus. Again as you have heard us say, we would hope you to have -- but I think it is probably not that difficult to develop longer-term forecasts of that same kind of information. Bearing in mind -- and this is one of the points that came up yesterday -- that some of the load research that has been discussed and that the company appears to be already committed to undertaking, is going to give you the basis for some of that kind of analysis.

They are already committed to doing load duration or load profile kinds of research on the different customer classes. And I think they had expected that that would be helpful even in the embedded cost analysis. But that is the same information you would use in a marginal cost analysis.

MR. GARWOOD: Yes. I don't recall the vintage of those numbers off the top of my head. So to the extent they aren't reflective of the change to conditions we are experiencing here with increased energy prices in general, you would want more current information as you could get it.

MR. SOLLOWS: Thank you. Now I think, Mr. Adelberg, I think I have heard you say yesterday that on-peak and off-peak supplies are not interchangeable.

And my understanding was that thermal energy storage technologies would allow a customer to shift, to substitute off-peak energy for on-peak loads for space heating or water heating, basically controlling the water heater so it doesn't operate on-peak or controlling your space heating so that you use off-peak energy to store heat and then distribute the heat in the house.

So I'm trying to -- I'm a little bit confused. Because my understanding seems to stand in contradiction to what you have said about on-peak and off-peak not being interchangeable.

MR. ADELBERG: Okay. You are talking about technologies that allow a very limited amount of shifting between on-peak within a day for example. But generation is generation of a kilowatt-hour in March for example and December. It is not an interchangeable product. You probably would not be able to store your heat for four months.

MR. SOLLOWS: No.

MR. ADELBERG: So there are some limited situations. But even among those, what those technologies are benefiting from is the very fact that there are separate products being sold at different times.

If the commodity became interchangeable and the price was the same, there would be no incentive to do that. So they are in fact -- they are very carefully geared to the fact that they can buy a different product at a different time of day at a different price.

MR. SOLLOWS: Right. And so that was the point of your comment?

MR. ADELBERG: Yes.

MR. SOLLOWS: I see. Okay. Now we have had more than one reference through this to the cost of the Coleson Cove refurbishment. And it is my understanding that there were -- really that was -- there were a number of aspects to that project.

One of them, and I think perhaps even the largest portion of the expenditure, was related to environmental upgrades. And then there was a significant amount of money expended for fuel to -- for future fuel savings that may well not arise.

But I guess my question is are we clear that we aren't just talking about the refurbishment as a single project and we are talking separating the capital cost to the different intentions?

And if we do separate the cost to the different intentions, environmental upgrades versus fuel savings, does it have any impact on the cost allocation that results?

MR. ADELBERG: Well, I guess we can both chime in on this. But it depends again on if you maintain the policy that we have discussed, that some of us believe that you had coming into this case, where you used a 40/60 split, that will affect the cost allocation. Because that 40/60 split would be applied to any investment whether it is the original or the incremental.

If you -- if one were to adopt or use the more traditional peaker credit method, then under that method you really don't care what the character of the fixed costs investment is.

In this case the record -- the dollars per kilowatt was about $800. That was deemed to be the price of a combustion turbine. And anything in excess of that for whatever reason was energy -- was associated with energy.

So it depends a little bit on which way you go on that. But beyond that, if you think of it from a planning point of view, if you go back to sort of the theoretical underpinnings of the peaker credit method, the planner would look at -- again they would look at their alternative plant options.

And it may be that a cycling plant, a non-peaking plant, the costs have suddenly gone up because the environmental regulators have said you have to control your emissions on it. Well, that doesn't -- that is certainly the case, that it doesn't mean that you are getting any extra energy benefits out of that plant.

But it is very much -- it is just part of the inherent economics of operating that plant. It is going to affect when -- where in the economic analysis, the break-even point comes for favoring that plant. They are going to be a little less attractive as you add costs to them. But they are costs like any other capital cost.

Steve, did you want to amplify on that?

MR. GARWOOD: No. That is exactly the way I see it as well.

MR. SOLLOWS: Okay. Thank you. I'm going to jump ahead to a question here. Because it relates to this notion of peaker credit. And I checked the -- my recollection last night on my laptop and went back and checked.

Since 1993 the capacity factor on the gas turbines for in-province load I think is less than 1 percent in this province. And there are many years in that period where less than I think it is .3, .2 percent, very, very small utilization.

That leaves me somewhat uncomfortable basing the cost allocations on those kinds of costs. Because it doesn't seem that they really reflect the situation. For whatever reason those plants were built they don't seem to have been very -- turned out to have been necessary from a peaking perspective in this province, and probably largely because of the energy-limited hydro that we have.

MR. ADELBERG: Right.

MR. SOLLOWS: So given the fact that I said that I'm uncomfortable basing the cost allocations on those costs, I would just like to give you the chance to comment.

MR. ADELBERG: I'm going to give my briefest thoughts. Steve may do a better job than me. But there is -- I guess there are a couple of things.

One is presumably at the time they were installed one expects that they must have had some value or they wouldn't have been built. I mean, there had to be a reason for them. And now obviously what has happened is you are in a period of surplus capacity, excess capacity. Plants just don't run on excess capacity.

So my other thought was that there is -- my recollection is there is an aspect of the Peaker Credit Method which basically says you look at what the least capital cost alternative of the system that you are examining is.

And it may not be a peaker. There are some systems in which the nature of the load may be such that you would never put a peaker in. In that case you use what is the next least cost option, which may be a cycling plant or something else.

But when you are in a long-term situation of excess capacity, I agree, it seems odd to be basing it on decisions that were made a long time ago, but those are still the framework that we have.

Steve, did you want to --

MR. GARWOOD: Well, I was going to say, I agree with you. It is the framework that is traditionally adopted for use in embedded studies where you would be reflecting your, you know, so-called traditional technology for the cheapest form of installed capacity. And that happens to be CTs.

Certainly in a marginal cost of service study, and was exactly the case in some of the versions of the study that I had submitted -- that I had done for Central Maine Power Company and submitted in an Interrogatory in this case -- you do get away from being so tied to just the use of a CT for determining your marginal capacity costs.

For instance in that study, in the early years the company was in excess, as was generally the region, New England, the marketplace in which the company would acquire capacity on the marketplace. And in those early studies the cost of capacity during that time was viewed as what it could get it out on the marketplace if and when it needed it.

And so at that time, with the region in excess, it was a very low-cost option reflected in the marginal generation capacity cost of that study as compared to what you see in later year versions, the versions that went out 10 years or so. And in the 10-year version when you had used up your excess, or at least your forecast showed your excess had been dried up, not only within your own utility, but regionally you simply capped your cost at what it would cost you to install a CT.

So I'm experienced in reflecting something other than a CT in a marginal study to reflect current conditions. But my experience with embedded studies is that you would still look at utilizing the traditional approach, if you are going with this Peaker Credit Method, and look at the cost of a CT.

MR. ADELBERG: I guess if I could just -- now that I have reflected on it for another minute or two, I mean, that is exactly the kind of concern about embedded cost studies that causes a lot of economists to say these don't make any sense. You are making cost allocation decisions and rate decisions based on information that can be ancient and cost information that can be ancient and decisions that are ancient.

In the marginal cost study you may well conclude, if you don't need capacity for several years, that all of your capacity costs are infamarginal, that they are not going to be the basis of your marginal cost rate design. They will be collected through the demand and elastic portion of the rate so as not to distort the price signals you get.

MR. GARWOOD: The situation in New Brunswick looks very similar to the situation that the Central Maine Power Company was under when I had done that last marginal cost study with power supply if you -- if the load forecast of the utility in its excess capacity situation is found to be accurate. You have got a lot of excess it appears in the early years. And then later out in the years you slowly use that up as you go through time.

So if I came into the company and did a marginal cost study I would probably use the same techniques that were used back in that case, where I would look at what I could get it on the market. And that would reflect my marginal generation capacity costs in the early years. And I would over time build it up to the maximum cost of installing a CT.

MR. SOLLOWS: Thank you. I guess that leads into my next question. And that relates to the need or expectation of new capacity coming online. I think everybody here agrees that the evidence is clear that there is no need for new capacity for the next few years. But I still read headlines that there is plan to develop 400 megawatts of wind energy.

I know that there have been recent unit additions for combined heat and power unit additions very recently and upgrades of small hydro that are covered under the private purchase power agreements between Genco and private power generators. And so in spite of the load forecast we still seem to add capacity.

And my question is how should that disconnect between the agreed lack of need for capacity and the continuing addition of capacity, how should that be handled? And what would be the impact in the cost allocations?

MR. ADELBERG: That is an excellent question. Obviously the rationale for adding that has to be that there are environmental benefits or social benefits in encouraging a renewable resource as part of planning for the long-run future. They are not part of the economics of the immediate need for power.

I'm struggling a little bit. Because actually this issue does come up and has come up recently. Because they have -- even under restructuring in New England they have -- and other parts of the country, they have these so-called system benefit charges which are designed and are used to pay for conservation programs and renewable energy, even when it is not strictly speaking economic or needed for the system.

And why I'm struggling is that I had seen some analysis of how this has been billed. And my hunch -- see, I hope you have more familiarity with this than me. My hunch is that it is more a political decision than an economic decision in that they are allocating -- they have been allocated just equally as a surcharge on every kilowatt-hour of power consumed is probably the way it is done, just because it is viewed as a social program, but --

MR. GARWOOD: Yes. I think that is a common way to state -- again it is state by state. But, you know, these are socialized costs, you know. You can view them as a tax.

MR. ADELBERG: That is the best way to look at it. It really is like a tax.

MR. SOLLOWS: So if we wanted to treat it in the same way, what level of -- is there sufficient information in the evidence that we have to pull out these CHP units and the wind stuff -- well, I guess there is no wind can be on the system for the test year, but the CHP data for the private power generators, and reallocate that so that it is essentially a tax on everyone rather than flowing through the Genco PPAs?

MR. ADELBERG: Again that is probably better addressed to Disco. But as you mention that, in the case of CHP, one other issue that comes up, and has been the basis for allocating these costs in my experience is to the extent that programs tend to benefit a particular class more than other classes. Sometimes they are allocated largely to that class. That was very much the case with conservation programs.

And CHP -- the problem with CHP is I would suspect it benefits a particular customer more than a class. But even so you might focus it on the class where the benefits are being realized. But it is one option.

MR. SOLLOWS: So in that you would be suggesting that the costs associated with the private power contracts for the cogenerators or CHP plants would be directly allocated to

I guess their large industrial class?

MR. ADELBERG: Again you are going to have equity concerns no matter how you do it. It was easier with conservation programs, because they were intentionally designed as much as possible to be available to everyone in the class.

So in your industrial class I don't know whether these alternatives were universally available. If they are, there is an argument to be made that you shouldn't have another class contributing to the cost.

But again if the theory is -- the underlying theory for doing it was this was a benefit for the environment, then presumably everybody benefits by a cleaner environment, so --

MR. SOLLOWS: Thank you. Just two more. No, sorry, three.

Now moving on to the issue surrounding transmission customers of Disco. As I understand it transmission customers can leave now. And the current situation is in this province their only potential supplier would be Genco. Since they are transmission level customers they are not bearing any of the cost of the distribution system as it stands.

And since -- at least in the case of transmission, large transmission customers, their revenue cost ratio is less than 1, I can't see how there would be any need for an exit fee hearing in that case. We all benefit if they leave, right?

MR. ADELBERG: If it were on an incremental cost basis I would agree with you completely.

MR. SOLLOWS: Okay. So I guess my question really is is why no just set the transmission rate at full cost recovery and just leave it to Genco to provide any subsidy to service if it sees fit? Because it can do its own thing irrespective of Disco if it wants to sign a contract.

MR. ADELBERG: You just stated again -- and I want to pick it up. And it is not your problem. As you were saying it you were causing me to think about a related issue which has to do with -- if the concern is about exit fees. Is that part of the --

MR. SOLLOWS: Well, we have heard the concern that because Disco has not brought forward a proposal to develop exit fee, hold an exit fee hearing, there is no market. But realistically there is a supplier. These customers are being supplied by Genco's resources now.

Were they to leave, choose to leave because their revenue cost ratio for their class was set to 1, they would certainly be able to negotiate directly with Genco for service.

And if Genco decided as a matter of public policy that it wanted to offer below cost pricing to them, it would be their business essentially, would it not?

I'm trying to see why there is -- what the rationale is for setting the revenue cost ratio below 1 for the large industrial customers?

MR. GARWOOD: Those ratios now aren't really indicative of necessarily the going-forward cost to Disco of maintaining them on the system. And I think, you know, that is kind of in the -- that is tied up in the discussions we have had about incremental or marginal cost versus the historic relationships that are evident in the embedded cost world. But it seems to me -- and I guess this does go back to just the exit fee issue. I'm assuming there are lost revenues above cost that materialize as a result of those transmission customers choosing to leave like that and deal directly with Genco that would have to be dealt with or, you know, just allocated back over to the other rate classes.

I'm assuming it is not a, you know, one for one tradeoff, that you lose -- that Disco is relieved exactly of the costs equal to revenues that are also lost, so that there is no net zero sum gain or loss to the utility, and its other customers if this happened.

MR. SOLLOWS: The Chairman tells me it is irrelevant to the proceeding anyway. So I will just move on to the next one.

CHAIRMAN: It is probably a regulatory first when the Chairman has to overrule the question of the Commissioner. But if it had come from any of you I would have had to do that. So I think it is only appropriate and fair. Carry on.

MR. SOLLOWS: Expert revenue allocation. Disco proposed allocating all of that revenue to demand, which if I understand if correctly tends to favour residential customers. I think both you and Dr. Rosenberg have suggested using -- actually looking at the results of the export bids and contracts and if they are capacity contracts allocating to demand, and if they are energy supply contracts allocating to energy, is that right?

MR. ADELBERG: That's right.

MR. SOLLOWS: I guess the question, the reservation I have in my mind about that is wouldn't that -- adopting that approach allow Genco's bidding strategy to influence the allocation indirectly and they may choose to bid in more to demand or more to energy, for whatever reason. And I am wondering if because of that concern I would like you to -- give you the chance to comment on the same thing I asked Dr. Rosenberg to comment on the notion of basing the allocation on inverse proportion to the load factor for the class?

MR. ADELBERG: Well that -- and that's sort of several pieces of that question. I would think from Genco's point of view, you have to go back to those sharing mechanisms in the PPA, which section 6.3, I think was the section I recall. I may be wrong. And Genco I think -- the incentives I think under those agreements -- under those provisions are for Genco to maximize its revenue. It doesn't care how Disco allocates Disco's share of that revenue, because it gets a formula piece of that revenue before Disco gets anything.

And actually it is coming back to me that there is -- I believe that once you get outside the band width, the revenues are shared 50-50. So that would say that Genco has an incentive to maximize its revenue and to sell whichever product it can, whenever it can make more than its marginal cost of doing so.

MR. GARWOOD: And it seems to me that that will be driven largely by what the marketplace that it is selling into is in need of. So, for instance, if New England were itself in a huge colloid of capacity, and didn't require any, that's very likely New England market participants would very infrequently, if ever, come to New Brunswick looking for capacity. And therefore, if New England was its only marketplace for exports, then they have zero capacity transactions and the only -- and engaged in energy transactions. And it would seem odd under that condition to be crediting all of those revenues to the demand side of the equation.

MR. ADELBERG: And the fact of the matter is usually when you have a sale opportunity, it's not either or. In other words, you can sell both at the same time.

MR. SOLLOWS: Thank you. And you have no comment on the notion of allocating based inverse proportion --

MR. ADELBERG: No, I am sorry. That was the second part that I -- I hadn't got passed the first part. So can you state again what --

MR. SOLLOWS: Just the notion that to -- a third option of simply looking at the load factors' class by class and allocating a revenue in inverse proportion. So a low load factor class would get more of the revenue presumably because they bear some responsibility and some of the cost for having -- made the surplus capacity available?

MR. ADELBERG: Yes, I have to think about it in steps, because again a lot of the fixed costs of Genco are being allocated on an energy basis.

MR. SOLLOWS: Okay. It may not be fair in that case to do it according to load factor?

MR. ADELBERG: Right.

MR. SOLLOWS: Fair enough. And my last question is unfortunately perhaps the least focused. But -- and I just want to get your thoughts on rate design generally and sort of the -- the kind of very simplistic approach that I might be inclined to follow, and since it's -- I don't have to be in my normal life terribly concerned about the real world, I would like to give you the opportunity to critique it.

As I understand pricing, we really want to make sure that the marginal cost to the customer reflects the marginal cost of supply. And we generally accept for this kind of business, we are talking long run marginal cost, is that fair?

MR. ADELBERG: That's -- well, long run versus short run is a policy decision. We tend to prefer long run. Although remember that -- and this is an area that I think a lot of people misunderstand about long run versus short run and marginal cost analysis. Long run marginal cost analysis is not really a temporal issue. It's not the lay person's concept of what long run is. Long run is -- it means -- short run means that it is the marginal cost assuming your fixed plant remains unchanged. Long run just means you are changing it. So that you are having to change your fixed costs of your generation portfolio.

So your long run could be tomorrow. And your short run could be five years. So that's why there is --

MR. SOLLOWS: So I guess when I look at the evidence that's come before us, I look at the cost of energy under the power purchase arrangements that we have seen and say well, you know, that's a contract that's been signed between Genco and the supplier. It's a certain cost per unit energy. And it's a fairly recent contract. So to me I look at that as a good proxy for the long run marginal cost at least at the transmission level. Am I wrong to think of it in that way?

MR. ADELBERG: Again, the -- what the Genco is billing is average costs, not marginal costs.

MR. SOLLOWS: I understand. But the -- within their power purchase agreements for the energy that they buy from the private generators, I seem to recall a binder coming in front of us that had a certain amount of energy for a certain amount of dollars for the test year and when you divide the two you got a fixed -- you know, a cost per kilowatt hour for that -- for that energy, which presumably includes fixed costs. And so from a -- I guess I look at that and say well that's a good proxy for the long run marginal cost of energy, because they are buying energy. They -- presumably, the company is being reimbursed for its capital cost, as well as, its fuel. And that looks like the long run cost to me. However it is passed through the PPA between this -- Genco and Disco, that's where the margin has come from isn't it?

MR. ADELBERG: No, I don't -- well, I may be misunderstanding you. But typically you would view the margin as being the cost associated with -- not with your existing consumption, but with the change in consumption, either up or down. So you really aren't -- you really aren't looking at simply what you are paying today in the average cost of the inputs that go into it. You are saying I want to tell the customer if he changes his consumption pattern how will the cost of serving him change. And that's not going to be average cost. It's not going to be the cost of contractual commitments. It's not going to be the cost of contracts that were negotiated before. It's going to be looking today or tomorrow, what's going to happen if the consumer changes his consumption.

MR. SOLLOWS: But practically -- I mean if I have a contract that was signed 10 months ago for 25 years of supply of energy at a certain price, might I not have a reasonable expectation that I could get a contract for a similar price next year or this year? You know, what I am trying to move away from is this notion of the embedded costs to what the cost of energy was most recently demonstrated in terms of a contract between two independent companies?

MR. GARWOOD: It seems if you -- it seems to me that if you were looking at your load forecast going forward from today and saw a need to acquire additional resources and you, as in your hypothetical, you had a contract you just signed 10 months ago, if you truly believe you could get an identical contract or similar contract to satisfy that incremental load, then you might be able to rely on that contract as being indicative of what it would cost you to acquire the additional resources and, therefore, it might have some semblance to the marginal cost of serving that load. Although probably if you compare your hypothetical 10-month old contract to current conditions, you might not believe you could get that same contract just given what we have seen as a rise in energy prices generally.

MR. SOLLOWS: All right. I think I understand that. Assuming in some way though I have that estimate of the long run marginal cost, wouldn't I want to design a rate structure that made sure that every customer saw that for their last incremental kilowatt hour of purchase?

MR. ADELBERG: If the -- I guess that to my mind would work with two other conditions. One is is this contract supplier going to supply whatever your requirements are, whether they change or not?

MR. SOLLOWS: Yes. In this case it's a must run contract.

MR. ADELBERG: Well, but that's supplying what his output is. It's not supplying what your requirements are.

MR. SOLLOWS: Yes.

MR. ADELBERG: Your requirements might go up beyond what that supplier can provide, then you have got another issue.

MR. SOLLOWS: Right.

MR. ADELBERG: The other factor that has come up already in these proceedings is that there is another secondary economic impact of consumption decisions by Disco customers in that the Genco can sell off power that is not needed to supply Disco. And so you have to take into consideration what's the incremental or the marginal value of that energy in the market. So it's again as we have pointed out there are some -- there is some friction in Disco's ability to reduce its take, but at some level if it reduces its take, there is more money that comes into Genco and there is less cost that goes to Disco.

MR. SOLLOWS: Okay.

MR. GARWOOD: The other thing I was thinking about in looking at this type of a contract is depending upon how the pricing under the contract is may or may not avail itself to easily being reflected in a good rate design to send the proper price signals.

For instance, if it was a contract where it was simply a dollar per kilowatt hour payment to the supplier and not separated into demand and energy components, then you might be hardpressed to reflect in a good rate design the kind of price signals you would want.

For instance, if you were in a situation where you really didn't want to encourage a growth in demand, but you could encourage a high utilization, you would ideally want to see higher demand charges in your rate design to send that price signal and an energy price that might encourage additional use.

So there may be some limitations I guess on what you gain out of looking at a current contract based on the detail -- the details in the pricing of that.

MR. SOLLOWS: Thank you. So I guess where I am coming from with this is if I somehow settle on a reasonable estimate for the long run marginal costs and leaving aside demand charges, I am thinking mainly about residential or energy-metered customers who don't have a demand meter or we aren't using demand metering to keep the costs a little lower, it seems to me that if I have the long run marginal cost or an estimate for it, I would want the run out rate to be set at that, you know, in a blocked structured rate, is that not right?

MR. ADELBERG: When you say the run out rate, you are referring to --

MR. GARWOOD: Tail block, I think he is referring to.

MR. SOLLOWS: Like a two block -- where we currently have a two block system, with the run out rate being the second block proposed to infinity, the tail block?

MR. ADELBERG: Tail block. That's another complexity. If you -- it depends a little bit on where you expect -- which customers you expect will expand their consumption. If your electric heat customers are essentially maxed out and they are using everything they can, and if anything, they are probably thinking about taking out their electric heat, and what you are really expecting is your nonelectric heat customers to buy more computers and television sets, then your margin may be -- may not be in a tail block.

We had that experience in trying to set a -- when we were long in capacity in the 1990s, and we were trying to protect our -- as a electric utility, protect our electric water heating load, we actually found that we had to make an adjustment in the middle block, because that's where we figured that the decision was going to be made by the customer on the margin about whether to use electric water heating or oil or gas water heating.

And in many cases, you are right. If you put it out, you sort of figure if all your customers are going to be -- or are at that -- consuming that in that tail block and that's where you want the signal, but if you think they are -- that's not really where the added consumption is going to come from, you may not --

MR. SOLLOWS: Well, you are getting at the point that I am sort of trying to struggle with here, too. In that as I see it from a basic economics perspective, you want every customer to see that final marginal cost. So we want that tail block to be at the long run marginal cost.

The first block, it seems to me that if I need to pick a number, I would pick the short run marginal cost and then I would adjust the block size to meet revenue requirements.

Now the practical problem with that I can see would be that unless all of your -- the customers in a class have about the same annual consumption, it could be very, very inequitable?

MR. ADELBERG: That's right. That's the problem you have. And that's why you get into some -- and one of the things that we did in Maine -- they experimented with in Maine, unfortunately, again ran into some political opposition, but they tried to get at the capacity costs associated with electric heat -- and this came up I think yesterday -- by having a additional charge depending on the amperage of your -- you know, your electrical box at your house. And they figured people with electric heat used 200 amp service, people without it used lower amperage. So they had a charge that was associated with the service. And one of the objections you run into is that that creates an incentive for homeowners to put in undersized connections in their house which is not safe. The electricians came in and complained. So it gets to be complicated.

MR. SOLLOWS: Yes.

MR. ADELBERG: But, yes, targeting the part of the rate class that you want to target is not an easy matter. The load research that the company has undertaken will be helpful.

MR. SOLLOWS: Yes.

MR. GARWOOD: But you really need more end use research for that endeavour.

MR. ADELBERG: End use. That's right.

MR. SOLLOWS: Okay. No, that's all I really wanted. And the key issue here is not so much designing an economically efficient rate, it's the designing one that is also equitable and delivers the right revenue requirement.

MR. ADELBERG: Absolutely.

MR. SOLLOWS: Thanks very much. Those are all the questions I have.

MR. ADELBERG: Your welcome.

CHAIRMAN: Thank you, Commissioner Sollows. We are going to take our break in a just a minute. We come back for Mr. MacNutt's redirect, if he has any. He has got one question, he signifies. And if any of the parties have questions of the witness based upon the Panel's questioning of this witness, why I give you that opportunity as well at that time.

Now, Mr. MacNutt has indicated to me prior to the commencent of the sitting this afternoon -- this morning -- it feels like afternoon already -- that we probably will need a Motions Day in reference to the rate portion of this hearing. That's my appreciation of it, Mr. Morrison?

MR. MORRISON: I think Mr. Hashey and Mr. Hyslop have had many discussions about this and I think a Motions Day is inevitable, Mr. Chair.

CHAIRMAN: All right. Let me see, is it Mr. MacDougall that has the week of the 14th to the 18th on a trial elsewhere, is that correct, Mr. MacDougall?

MR. MACDOUGALL: Mr. Chair, I don't think you have to worry about our participation in that Motions Day. If Enbridge is going to attend on that, we can certainly send someone else. So don't worry about my issue --

CHAIRMAN: Appreciate that. While I was taking a quick peek at the scheduling and, of course, here we go because we have pushed things in so close together in trying to get things wrapped up. It's extremely difficult to schedule a Motions Day and, of course, impossible to set it really before the responses are to be out to that first set of interrogs. So we are going to have to do it after. But certainly I -- what we will do in the break is that we have made connections with the Board's office in Saint John and we are going to get some calendars printed off up-to-date, so that we can look at it. And I suggest during the break that you folks do the same. Take a look at your calendar for the month of November as to what your appointments are and when we come back in, we will talk about when we could possibly have that Motions Day. Yes, Mr. Hashey?

MR. HASHEY: Mr. Chairman, I would also like at that point to discuss the proposed schedule on the Rogers' portion of the rate hearing. I have --

CHAIRMAN: When we come back in?

MR. HASHEY: Yes. I have dates and I don't know how you would like me to handle that. But I have talked to Ms. Milton and Ms. Vaillancourt I believe is here --

CHAIRMAN: Oh, you mean as to when during the rate hearing, we are going to look at that?

MR. HASHEY: Well when the evidence has to be filed, the interrogatory dates, all that type of thing for that portion of the matter that's now under your jurisdiction.

CHAIRMAN: I was hoping that you would sit down with Ms. Milton and come up with a schedule?

MR. HASHEY: I have done that.

CHAIRMAN: Oh, well, then that's not much of a --

MR. HASHEY: But we don't --

CHAIRMAN: -- conversation. You don't agree?

MR. HASHEY: We don't superimpose ourselves on the Board's decision.

CHAIRMAN: Well, that's fine. But if you have agreement on that we will take a peek at it, Mr. Hashey.

MR. HASHEY: Would you like me to deliver a copy of that to you during the break?

CHAIRMAN: Yes. Might as well, that would be great.

MR. HASHEY: Thank you.

CHAIRMAN: Well look we may take longer than our normal 15 right here until we get the calendars downloaded and take a look at it. And I would suggest that if any counsel are tied up -- the 18th of November is out. The Board has to make its annual appearance before the Crown Corporation's Committee of the Legislature. And it's a Friday. So, but otherwise if anybody is tied up, 14, 15, 16, 17 --

MR. HASHEY: I am.

CHAIRMAN: But let -- well, I mean able counsel has been here in your absence --

MR. GORMAN: Mr. Chairman, I am also tied up. I just note from the draft schedule that we had been given earlier on that there was a Motions Day scheduled if needed for the 2nd of December.

CHAIRMAN: The problem here is, Mr Gorman, from our perspective is that this is the first set of interrogatories. And if we don't rule on whether or not Disco has to answer or not answer at an early date on that first set, then you are going to have a parallel set of interrogatories going maybe later on. So that's why we are trying to set an earlier date. And did you indicate that you are tied up, Mr. Gorman, in that 14 to 17 period?

MR. GORMAN: That's correct. I am out of town that entire period.

CHAIRMAN: We will move the hearing out of town.

MR. GORMAN: How far are you prepared to go?

CHAIRMAN: Anyway, I know you have partners, but --

MR. GORMAN: The 17th actually would probably work, but the other -- the three days before that would not.

CHAIRMAN: Well, all right. You folks if you have some thoughts perhaps you could speak to Mr. MacNutt on the break.

MR. GORMAN: Thank you.

(Recess - 10:40 a.m. to 10:55 a.m.)

CHAIRMAN: That was quite a long break. The Panel has one question left. Mr. Bell, go ahead.

MR. BELL: Good morning. My question is -- I guess is on your experience with the -- that you have seen with the introduction of seasonal rates. And more specifically, in those jurisdictions where you observed the introduction of seasonal rates, were there budget programs available for residential class ratepayers?

MR. ADELBERG: Yes. That has been our experience, budget programs are very important. And of course, budget programs in a sense there is an irony to it, becuase in some extent it could be viewed as cancelling the signal, but --

MR. BELL: That was my concern.

MR. ADELBERG: But by the same token, there is a message to customers who are going on a budget plan, that the reason they are doing it is because if they don't, there is going to be higher seasonal rates. So it is a little bit of a mixed message. But on balance, it's preferable -- or my experience it was preferable to no signal at all.

MR. BELL: You still had seen some reaction by way of demand management with regard -- with the reaction to the signals, even though they are paying a flat fee?

MR. ADELBERG: Yes. I mean, it's not a controlled experiment. So you don't always know. But the sense is that people who are aware -- that the communication that the utility goes through in a process of getting people enrolled into the budget plan itself sort of informs them that the reason you need a budget plan is because it's now costing more to heat in the winter or to use electricity in the wintertime and therefore, you know, why don't sign up with one of these programs. So yes, the customer can somewhat soften the signal, but at least in the process they are learning and they are getting a message as to -- you know, next year or the year after, their budget plan may be better if they find a better mix of appliances or whatever it is that they are using energy for.

MR. GARWOOD: And presumably they are still seeing their actual bill, even though their payment may be flattened. And, you know, also routine communications as bill stuffers can pass along or reinforce the message that's attempting to be sent about prices.

MR. ADELBERG: Yes.

MR. BELL: Okay. Thank you.

CHAIRMAN: Now do any of the Intervenors or the applicant have any questions arising from either Commissioner Bell's or Commissioner Sollows' questioning?

MR. MORRISON: No, Mr. Chairman, we don't.\

MR. GORMAN: We have no questions.

MR. MACDOUGALL: We have no questions.

CHAIRMAN: Silence is acquiescence. Mr. MacNutt, go ahead with your questions.

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

MR. MACNUTT: Thank you, Mr. Chairman. I have just have one question.

Q.606 - Mr. Adelberg, yesterday, Mr. MacDougall asked you a question in respect of Energy Advisors' response to PUB EGNB IR-7, which sought confirmation that you agreed with the company's choice to use the Peaker Credit Method of cost classification as stated on page 5 of your report.

There was a part of that exchange I thought I heard you agree that Peaker Credit Method is based on the principle of cost causation.

Now if I heard you correctly, would you please explain in what context you were using the phrase "cost causation"?

MR. ADELBERG: Yes. Cost causation in the context of the use of the Peaker Credit Method, use of that method has to do with classificaiton of costs between demand and energy. It does not -- in that context it does not have to do with the allocation of costs between customer classes. So I just wanted to clarify that when we -- yes, it is based on a principle of cost causation, but only within the context of classification of costs, not allocation of costs.

MR. MACNUTT: I have no further questions, Mr. Chairman.

CHAIRMAN: Thank you, Mr. MacNutt. Mr. Adelberg, Mr. Garwood, we want to thank you for your participation in the hearing process. And by the feeling of this room here this morning, we are going to have a cold winter. So you came at the best time of the year. Anyway you are excused.

MR. ADELBERG: Thank you.

CHAIRMAN: And again thank you.

MR. GARWOOD: Thank you.

CHAIRMAN: Now first of all, Mr. Hashey supplied the Board with the agreed upon -- between Disco and Rogers a proposed schedule. Mr. Hashey and Rogers, we have no problem with that at all. And we will integrate that into our hearing scheduling. However, as to proposed hearing dates, it may be my fault, but as far as the Panel is concerned, you are now -- Rogers is now part of the rate portion of the hearing and simply will proceed with its evidence in accordance with the ordinary order of cross examination. Simple as that. So it fits right into it. Any questions on that?

MR. HASHEY: Yes, Mr. Chairman. I believe at some point, Ms. Milton and I talked about this last evening. That we should set a specific date during the hearing. This would be one area where there will be expert witnesses. They will be coming from out of province and they are busy people, it will be necessary to schedule them. The only reason I didn't put a date down here for that was Ms. Milton's request because the dates that we had initially put down was the end of January, the first two days of February. We sort of figure it may take three days.

CHAIRMAN: Mr. Hashey, we are going to run into that with each and every Intervenor, if they all decide that they want to have experts in reference to the rate portion of the hearing. I see no difference in that regard. And certainly that was the case for a number of Intervenors in this cost allocation portion of the hearing. And counsel, as I would normally expect sit down ahead of time and try and divide up the days.

And I would suggest to you, sir, and to you madam, that that's the way we will proceed then. We will do them all at once and counsel will try and come up with a schedule as to where they fit in our reserved dates to accomodate everybody.

MR. HASHEY: Thank you, Mr. Chairman. We sort of thought it might be appropriate that it was at the conclusion of the other revenue portion, that's what we were trying to work toward, rather than mix it up in that. That's -- we were sort of gauging the time that that might take that was all and we will come back to that.

CHAIRMAN: Well, I appreciate that. And again when it comes time for us to look at that when the time periods have arrived, we will take a look at that seriously, because that might very well turn out to be the most convenient for everybody.

Passing on to the need for a Motions Day, Messrs. MacNutt and Goss have come back to me having spoken I believe with most or all of you and indicated that the

21st of November, which is presently set aside along with the 22nd for the Load Forecast portion of the hearing, that there -- nobody in the room believes that next year's Load Forecast is going to take the full two days. And that Motions Day could be fitted in there. And it's my understanding that the suggestion is that we start with Load Forecast on the 21st.

And then on the 22nd if there is anything left over, we put it on hold and when we rise at 3:00 in the afternoon on the 21st. And then on Tuesday, the 22nd at 9:15 we go through the Motions Day for whatever period of time it will take. Then after that is concluded, then we will go back to whatever is left over of the Load Forecast if anything. And that certainly is a good compromise, as far as I -- and the Panel are concerned, because that doesn't interrupt with any of the other things we have got and we don't have to look for hotel rooms.

Then Mr. Goss has also shared with me a tentative schedule concerning the dates that would flow if the Board were to rule that any of the interrogatories that Disco is objecting to, in fact they have to answer, and that schedule I will read it into the record. And please at the end of it correct me if I have gotten something wrong here.

But the -- as I said the Motions Day will commence on Tuesday, November 22nd at 9:15 a.m. Additional information to be required by -- in other words, as a result of our ruling of that date, that additional -- or sorry, the interrogatory that we have ruled on that requires additional information to be provided by Disco that will be provided by noon on Monday the 28th of November. And then on those questions and those questions only that we have ruled that Disco must answer for the Public Intervenor or any other participant that comes before the Motions Day -- in other words, any IRs that we have ruled must be answered by Disco, the second set of IRs by that -- for that interrogatory, whether it be from the Public Interventor or any other party, then that will be provided on Monday December 5th at noon to, of course, Disco.

And then Disco would respond to those second IRs on Monday the 12th of December at noon. And then the parties will give us notification of a need for a second Motions Day on Tuesday, December 13th at noon. And if necessary, the second Motions Day will occur on Wednesday the 14th of December at 9:15. That may be rather early if it's down to that. I am going to say 9:30 on that one, because it won't be that long I am sure. And if as a result of granting a motion or two on Wednesday, December 14th, there is additional information that has to be filed by Disco, that's to be filed on Wednesday the 22nd of December -- sorry, the 21st of December at noon.

And I will just go back. Mr. Goss is -- the tentative schedule I have just read back on Monday, December 5th, he has in here the second set of IRs by the Public Intervenor and other parties only on Public Intervenor-related questions.

That seems to indicate that the only questions that you presently have Mr. Morrison or Mr. Hashey that you are not prepared to answer are presented by the PI, is that correct?

MR. HASHEY: It's a little bit premature but our preliminary look see would tend to indicate that.

CHAIRMAN: Yes. Well, okay. Let's leave it this way --

MR. HASHEY: But certainly the vast, vast majority, no question.

CHAIRMAN: Oh, he is just terrible. Anyway, so I go back to what I said in reference to the Motions Day is it's basically PIs, but it could be another Intervenor and so they are all handled in the same way.

And the other thing is is if that information is forthcoming as a result of a Board's ruling on it, then any other Intervenor can ask questions concerning the information that is provided pursuant to those additional information supplied by Disco. Is that all clear as mud?

MR. HASHEY: Thank you, Mr. Chairman. I think that's quite clear.

CHAIRMAN: Okay. Great. Are there any other matters that we should cover now before we adjourn until next Monday? If not, then we will see you in this room next Monday at 9:15.

(Adjourned)

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of my ability.

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