New Brunswick Board of Commissioners of Public Utilities

In the Matter of an application by the New Brunswick System Operator for changes to the Open Access Transmission Tariff (OATT) as approved by the Board for the New Brunswick Power Corporation

Delta Hotel, Saint John, N.B.
March 30th 2005, 10:00 a.m.

CHAIRMAN: David C. Nicholson, Q.C.

VICE CHAIRMAN David S. Nelson

COMMISSIONERS: Diana Ferguson Sonier
Jacques A. Dumont
Ken F. Sollows

BOARD COUNSEL: Peter MacNutt, Q.C.

BOARD SECRETARY: Lorraine Légère

BOARD STAFF Doug Goss
Gay Drescher

.... CHAIRMAN: Good morning, ladies and gentlemen. If I could have appearances please. On behalf of the System Operator?

MR. WHELLY: Charles Whelly and Kevin Roherty.

CHAIRMAN: Good morning. And Transco?

MR. WHELLY: Charles Whelly.

CHAIRMAN: And WPS Canada Generation Inc.?

MR. MACDOUGALL: David MacDougall and Matt Hayes. And we will joined later by Mr. Ed Howard of WPS.

CHAIRMAN: Thank you, Mr. MacDougall. Formal Intervenors, Canadian Manufacturers & Exporters, New Brunswick Division? No one here today. Mr. Daly? Not here. Eastern Wind of course has withdrawn. Irving Paper Limited, Irving Pulp and Paper Limited and J. D. Irving Limited?

MR. PAPPAS: Yes. John Pappas. And with me is Andrew Booker.

CHAIRMAN: Where are you, Mr. Pappas? There you are Okay. And Disco?

MR. MORRISON: Good morning, Mr. Chairman. Terrence Morrison with me is Blair Kennedy.

CHAIRMAN: Good morning, Mr. Morrison. And Northern Maine Independent System Operator Inc.? Mr. Belcher. Nova Scotia Power Inc.?

MS. NEWMAN: Serena Newman, Mr. Chair.

CHAIRMAN: Thank you, Ms. Newman. Municipal Utilities?

MR. YOUNG: Good morning, Mr. Chairman. Dana Young.

CHAIRMAN: And the agent of the Attorney General?

MR. HYSLOP: Good morning, Mr. Chairman. Peter Hyslop and David Thorne.

CHAIRMAN: Just to know, are there any Informal Intervenors present, Trans Energie or Hydro Quebec? And NB Power Generation, Genco? No. Okay. And Mr. MacNutt, who is with you this morning?

MR. MACNUTT: I have with me Doug Goss, Senior Advisor, Gay Drescher, Advisor and David Young, Advisor.

CHAIRMAN: Thank you. Any preliminary matters? Mr. Whelly?

MR. WHELLY: Thank you, Mr. Chair. Yes, there are a couple. The first arises from an undertaking given arising from a question by Commissioner Sollows. And it relates to amortization. And we have a response. The question -- and in order to put this into perspective, what we are providing the Board is a response sheet plus a couple of other pages. And the last page is the page to which Commissioner Sollows referred in the annual report.

And he noted that in the annual report for transmission there was an accumulated amortization of 132,000,000 --

CHAIRMAN: Mr. Whelly, sorry to interrupt. But maybe it would be more useful if you waited until we got a copy of the exhibit --

MR. WHELLY: I'm sorry.

CHAIRMAN: -- to follow along on. Thank you. This document will be exhibit <u>A-14</u>.

MR. WHELLY: Thank you, Mr. Chair. Now referring to exhibit A-14, the last page, this puts the question in context. Commissioner Sollows had noted in his review of the annual report that accumulated amortization for the transmission system had gone from 126,000,000 in 2003 to 132,000,000 in 2004. And those numbers did not correspond to the $19 million expense that had been recorded in the material that we had provided to the Board.

As a result of that we have provided with exhibit 14 on the second page a breakdown of the amortization expense to the various components, various asset classes.

And the expense totals 19,000,000. But in addition it also shows -- for example in the second line, where we have the accumulated amortization for transmission lines going from 126,000,000 to 131.8'. And those numbers correspond to what was in the annual report.

MR. SOLLOWS: I think this is fine for now. The thing that ultimately I was looking for, but not in this hearing, but at a later date, was the breakdown of assets within those are the terminals, the ones at the generators, or the terminals at the substation where the property lines are.

Just generally when we look at these accounts we want some detail. But I think it is best probably to do this, not as a matter of a formal hearing but just between staff. Thanks.

MR. WHELLY: Right. That is fine. I'm sure that we can get the information you want.

The next preliminary matter, Mr. Chair, is a -- I will say it is a clarification. But it arises out of a concern that was expressed that we were presenting numbers to you in tables that sometimes didn't match or weren't presented the same way. So we at least want to cover off one of those concerns.

So as a result we are filing a sheet entitled NB Power Transmission OM&A Year Ending March 31, 2005.

CHAIRMAN: All right. That will be exhibit A-15.

MR. WHELLY: Now I'm going to refer to a couple of other exhibits in order to put this one in context. The issue comes up with IR-17 from the Public Utilities Board that was filed as part of exhibit A-3. And it is actually on page 28 of the responses that we gave.

And in that response, line 7, we noted that OM&A, the forecast for 2004, 2005 was 46.4 and the budget for 2004, 2005 was 40.6. So after having stated those numbers we then filed exhibit A-10 which didn't match them. So what we have done is filed the exhibit A-15. And this shows where the numbers came from that are in IR-17.

CHAIRMAN: Thank you, Mr. Whelly. Anything else, sir?

MR. WHELLY: They are the only preliminary matters that I have, Mr. Chair.

CHAIRMAN: All right.

MR. WHELLY: Thank you.

CHAIRMAN: I wonder if some -- we have got to keep a door open. I can't see. And I don't think they are open. Would the Public Intervenor perform a public service and -- oh, Mr. MacNutt has gone. Just keep her open. It is a public hearing. And people have to know they can come and go at will.

Any other matters from any of the other Intervenors or parties? Okay.

When we broke last Wednesday why Commissioner Sollows was questioning the panel. And Mr. Sollows, would you continue, sir?

MR. SOLLOWS: Thank you, sir.

BY MR. SOLLOWS: (Continued)

Q.489 - On Wednesday, it was March 23rd, we broke off, we were looking at page 1711 of the OATT transcript. That was December 18th hearing. I think you had it. It should be behind you still.

MR. MARSHALL: What was that page again?

Q.490 - It was page 1711 of the December 18 transcript. 1711. I guess for the record, position we were at on Wednesday is found on page 327 and following of the March 23rd transcript.

I asked you to read the statement you had made in response to cross examination by Mr. Nettleton in that hearing. Have you had a chance to read it?

MR. PORTER: No, but I will do so now. Which page again? I just want to confirm the page.

Q.491 - It's page 1711. And if you want to go to 1710, there is a lead in to it there that you might read as well.

MR. PORTER: Yes, I've read that.

Q.492 - In that statement you pointed out that the Pennsylvania Jersey Maryland ISO or PJM was in your view one of the most successful in establishing independent rules. And you noted that they charged the U.S. $100 per megawatt hour for imbalance energy. IS that right?

MR. PORTER: Yes, that is what the transcript reads, yes.

Q.493 - Thank you. Mr. Marshall, as I read the exchange on the previous page between you and Mr. Nettleton, I got the impression that the imbalance charge in effect at the time of the OATT hearing, that is prior to the tariff coming into place, was Canadian dollars per megawatt hour on the high side. And we changed it in the current tariff to, if I may quote you, "a cost that just reflects what the actual cost is". My question is is that a fair impression to have gotten from your evidence at that time?

MR. MARSHALL: It is correct it was $100 or 110 percent of the cost, I believe, in the current tariff. And in the current application before this Board it would be the final hourly margin of cost which is based on the bid prices of generators. So it is a market value, not a cost value. A market value.

Q.494 - But clearly the impression was reasonable for us to get the impression in the previous hearing that in your view the tariff reflected what the actual cost was?

MR. PORTER: I just want to add I think there is a timing issue. Really there are two different -- sorry, three different tariffs, I think, under discussion here. The tariff that was in place from '98 through to 2003, the tariff that has been in place since 2003 and is currently in place. And then what we propose here today. And if you look at Mr. Marshall's statements on page 1710, he is indicating that prior to 2003, the tariff that went into effect in January 1998, there was a fixed price on both the high side and the low side. And the high side it was $100 Canadian.

But what we were asking for at that time and what went into effect in 2003 was that the charge on the high side not be $100, it be a formulaic price which was in the order of magnitude of $100. But it was tied to a fuel cost index. So that was to reflect the actual costs not in a given hour, but the actual cost of a CT unit, which would --

Q.495 - I can probably clarify this by reading the words. It says, "The change on the $100 to a CT" -- that I take it is a combustion turbine based -- "on a fuel cost index, takes into account the fact that fuel prices are volatile and change". Go on to state "So it just reflects what the actual cost is".

MR. PORTER: Yes. That reflects what the actual cost would be if the combustion turbine was used. And what we ran into with the $100 that had been in place prior to that time was that as fuel prices increased, it got to the point where $100 did not cover the actual cost of the combustion turbine, so there were certain hours when the $100 did not even cover costs let alone provide a disincentive for parties to lean on the system.

Q.496 - And so fuel costs haven't gone down though?

MR. PORTER: No, the $100 would still not be enough to cover -- and I believe Mr. Marshall mentioned last week, it is really in the order of $150 a megawatt hour at this time.

Q.497 - Thank you. I am now going to read you your counsel's submission during his summation to the Board. It is made at pages 2556 through 2558 of the transcript of February 17th 2003. I think it will be marked.

MR. MARSHALL: February 10th?

Q.498 - February 17th, according to this. 2556, 2558 is the page number.

MR. MARSHALL: 2556, we have it.

Q.499 - Thank you. Just so that we are clear, there is a reference here into prices, I think you probably mean charges, but with that I will just continue to read what counsel said.

"Now the issue with respect to Emera and energy imbalance is really one of price. Emera has taken issue with the price which must be paid when NB Power must provide energy to compensate for a shortfall in delivery outside the 1 and 1/2 percent or 20 percent bandwidth. Their issue seems to be more with point to point service. Now the price stipulated in the tariff is 110 percent of the cost of the combustion turbine unit. Emera, in its evidence, suggests that the pricing is too high and does not reflect the market price of energy at the time that the energy imbalance is supplied. It suggests that the price not be linked to the price of the combustion turbine unit since it is not the most likely generator to be used to supply the imbalance."

It goes on to say, "Now there is no question the energy imbalance pricing contained in the tariff is a penalty and it is intended to be a penalty. In its evidence Emera states that there must be proper price signals to incent adherence to schedule. Now on cross examination I" -- this being counsel -- "asked Mr. Sidebottom a questions and he agreed that the pricing of energy imbalance must provide a disincentive for participants to lean on the system. Even so, Emera suggests that the price is too high and should be lowered."

"Now under cross examination by Mr. Nettleton, Mr. Porter stated that given the cost profiles of the market players, lowering imbalanced pricing would provide an opportunity for parties to game the system."

He goes on to state that "In my review of the transcript, that is the only evidence on that particular matter."

He sums it up by saying "It is our submission that the energy imbalance for pricing proposed by NB Power sends the appropriate price signal to deter gaming of the system. The only evidence before this Board" -- and this was in the OATT hearing -- "as I said, is that of Mr. Porter, where he suggest that lowering the price would encourage gaming".

That ends my quotation of counsel. I am looking now here in this hearing you are addressing energy imbalance in item 6, that is exhibit A-2, Appendix A, page 14. Ready?

MR. MARSHALL: We have it.

Q.500 - Starting on line 9 I find a sentence that reads "The revised wording will remove the penalty nature of the pricing with respect to forecast errors and individual hours."

And what I would like you to explain is what has changed between the time of the OATT hearing and now that has caused you to change your opinions which really appears to me in a very dramatic way?

MR. PORTER: There are two basic differences that have occurred, one being that we now have in place a set of market rules and the structure with the new legislation, all establishing a basis upon which suppliers can provide competitive bids for redispatch energy.

So what price they would need to either increase their output or decrease their output and prices that we would require to pay a generator for making up the energy differences when a transmission customer submits a variance or puts a variance on the system.

So that is the first part, is that we have that competitive priced dispatch that we can use for market settlement to settle for variances.

Q.501 - Can I just ask you to address on that point?

MR. PORTER: Certainly.

Q.502 - Would not these other System Operators like PJM, ISO New England or the other ones that you referred to in your OATT hearing evidence also have been running markets that would have these marginal prices?

They must have been dispatching generation and therefore must have had these merit order prices. Would they not also have had those but still imposed this energy imbalance fee?

MR. PORTER: They all would have an hourly market-clearing price. And in many cases they do use that market-clearing prices to settle variances that occur within that given hour. And that would include PJM.

And looking back at the transcripts, my recollection from 2002 is that PJM applied $100,h the penalty-based pricing on participants that were -- I believe it was wheeling through, that were not full-blown market participants at that time.

But for other types of customers, that were full-blown market participants, they would settle at the hourly market-clearing price. In New England they settle at the hourly market-clearing price. And in fact I believe PJM New York, I guess also New England, would settle at the clearing price at the specific node where the variance occurred.

Q.503 - But those are residual market, spot market-clearing prices and not the dispatch order that you would have.

Is my understanding correct that they will settle at the locational marginal price that is public and published?

MR. PORTER: Yes.

Q.504 - And that is not the nature of the price that you are settling at?

MR. PORTER: Yes. The price that we would settle at here is what we call the final hourly marginal cost which was laid out in detail in the market rules as to how that is calculated. That is something that we would publish.

There is an hourly value that is published, and it is on the website today, for the hours that have occurred December, January, February since the system's implementation date of December 1st.

Q.505 - But it is not available in real time?

MR. PORTER: But it is not -- no, it is not available in real time.

Q.506 - But it is available in real time in ISO New England for their market-clearing price?

MR. PORTER: Certainly available within the day, next day, maybe even within the same day.

Q.507 - The day ahead and the real time prices are posted?

MR. PORTER: They are posted, yes.

Q.508 - So there seems to me a very distinct difference between the nature of the information that you are basing your clearing price on and the nature of the information that people have access to in ISO New England. But we will carry on with your second answer.

MR. MARSHALL: One other comment on that. That issue of publishing the market-clearing prices and the timeliness of when that publishes is an issue that is in discussion before the MAC at this point in time. And that is subject to change on a go-forward basis.

The current rule that is in place is the rule to publish those after the fact monthly. Those were the rules written and accepted by the Minister of Energy that were put in place. And it required that they go through a full process to change them.

As I say, they are under discussion right now with the MAC. Depending upon the MAC view on that, they may change, they may not.

Q.509 - Thank you. Now you had a second point that you were making in respect to the general question -- the question I had posed, what caused you to change your opinion?

MR. PORTER: Right. The second part, and I think I had mentioned this last week as well, that with the restructuring and the fact that the New Brunswick System Operator exists as independent System Operator, we are in a much better situation to monitor any market abuses and oppose sanctions if necessary than was NB Power as a vertically integrated utility trying to administer the Transmission Tariff.

So at that time it seemed it was much more appropriate to have this Board approve a very clearly defined rate at which the energy imbalances would be settled.

Now it is -- with our independence and with the market price for settling, we can still continue to monitor -- the market-based pricing settles off a lot of the economic concerns. But the residual economic concerns and the operational concerns can be addressed through monitoring. And part of our role is to monitor the market jointly with this Board and to take actions and impose sanctions if necessary, if a market participant is intentionally using the balancing energy service to their benefit but to the detriment of other market participants or the reliability of the system.

Q.510 - So if I understand then, your position is that you think -- you accept that this increases the risk of participants gaming the system. But you think you are in a better position to deal or manage that?

MR. PORTER: There is a slight increase in risk. But the fact that the pricing is market-based mitigates a lot of that concern.

Q.511 - I guess as I look at this -- I guess I would like to give you a hypothetical. If you had a generator, say a 100-megawatt generator that is bid into you at let's say $40 a megawatt hour, and your market-clearing price is -- your market-clearing price is 60, and the New England market-clearing price is 80, wouldn't that generator that is only getting 40 from you be able to double his money if he just didn't deliver to you and signed a contract with someone in New England to deliver?

And wouldn't that be -- wouldn't there be an incentive there for them to move off schedule?

MR. MARSHALL: They have -- any participant in our market has every opportunity to sell into the New England market today. We do not block -- there is no barriers in any way to stop them from selling energy into New England.

Q.512 - Well, under the current tariff, if they went off of their delivery schedule, would they not face a payment -- a penalty payment of $150 per megawatt hour? And they would recover only 80 from their transaction. So net they would lose.

It seems to me that under the scheme you are proposing they would recover -- they would recover 40 and net -- and basically double the payment that they would be getting from supplying the New Brunswick system by going off of their schedule. It seems to create real incentive for them to leave schedule.

MR. MARSHALL: But they can't -- they have the schedule in this system. You cannot just sell energy into New England willie-nillie at any point in time. You require a schedule to do that as well.

So we are talking about a schedule into the New Brunswick system, into our marketplace. And it requires a schedule out of our system into New England. And it is then dispatched by ISO New England based on prices.

It is not possible to just stop from one and tilt and move energy from one to the other.

Q.513 - Well, you mean the generator as a market participant couldn't perhaps sign a contract to deliver energy into the New England market?

MR. MARSHALL: Certainly they could sign a contract to deliver energy into the New England market.

Q.514 - And so they could -- if they are a 100-megawatt generator, and you have dispatched them on economic merit order into supplying New Brunswick loads, and they subsequently take advantage of an opportunity to export into the New England market that doubles their money, aren't you going to have to make up the energy from somewhere? I mean, they only produce 100.

MR. PORTER: We would not accept a schedule for export from a facility which was already committed in the -- for the NB market dispatch.

Q.515 - Okay. So in the actual dispatch process you are limiting reservations of anybody or any generator that has been committed in the day ahead scheduling or --

MR. PORTER: We are limiting double-dipping on any generation capacity. We don't preference one over the other. But we would not -- whatever came in later, either a dispatch that would indicate that that generator is required for in-province -- we would have to have the exporting in place before the dispatch for in-province was performed.

But at the end of the day they would not have equipment for both in-province and export and then be settled on the variance on that. Because we would not accept those schedules.

MR. MARSHALL: Now if this is a concern to the Board -- I don't think this can happen because of the scheduling requirements under our market rules and the dispatch rules for it to happen.

But given even that a generator went on its own and tried to do something or leaned a little more from one transaction to another, our interest is in trying to get market prices and create a functioning market.

That is our mandate under the Electricity Act. And we want to get reasonable competitive prices on the margin for all players in the marketplace.

If this is a concern to the Board, that because we have a very nascent market and that the nature of the pricing in the New Brunswick market may be limited to the number of players, if it is a real concern to the Board, maybe an alternative might be to rather than just use the final hourly marginal cost in New Brunswick to settle the imbalance, we take the higher of the New Brunswick cost or the ISO New England price, and then if you go in the other direction, the lower of the New Brunswick price or the ISO New England price, that would still leave a little bit of penalty on either side or the other. But it would still be market-based pricing which would allow, you know, for indications in the market.

If the Board is concerned about this, that may be an alternative to consider. That is all I suggest.

Q.516 - Thank you. I want to go now onto item 8 which --

CHAIRMAN: If I can just interrupt for a second, Commissioner Sollows. Listening to the last exchanges here about the same day pricing, et cetera, you have on your -- and I forget the name of your secure website on pricing. What is that called?

MR. MARSHALL: OASIS.

CHAIRMAN: OASIS?

MR. PORTER: Yes.

CHAIRMAN: Yes. My understanding is that as at this point in time the Board does not have access to that entire site. We have a restricted access.

MR. MARSHALL: At this point in time there are a number of documents and information available on the public portion of that site. And there are a significant amount of other information available on the private portion of that site.

So that registered market participants and people that are able to play in the market have access to all the information in the marketplace.

CHAIRMAN: Okay. Would the System Operator ensure that the Board gets access to that entire site?

MR. MARSHALL: Certainly. We have a meeting scheduled next week I believe --

CHAIRMAN: Right.

MR. MARSHALL: -- with Board staff to talk about what information is required for the Board to monitor the market.

CHAIRMAN: Well, if we are going to --

MR. MARSHALL: I assume it will be on the agenda at that point in time.

CHAIRMAN: If we are going to monitor the market why we should have access to the entire site. Good. Thank you. Sorry, Commissioner.

MR. PORTER: I just might add that the one piece of information that we weren't talking about, the final hourly marginal costs, those are on the public portion and will be available there for anyone to see. They are clearly available today.

Q.517 - I would like to direct your attention to item 8 now of your proposed changes, which is to provide for automatic sharing of variances of non-dispatchable generators. That appears on page 21 of Appendix A, in exhibit -- or A-2.

Now in the OATT hearing on February 10th 2003, and it appears at pages 2261 and 2262 of the transcript -- I don't think you need to look it up, because I am going to read it. And if you want to check it against delivery you can.

The Board -- the Panel at that time heard of these examples with respect to handling non-dispatchable generators. Basically at that time wind generators. We heard that the California ISO allows for monthly netting of scheduling deviations, both positive and negative and waives penalties. We heard that the ERTCO ISO, which is the ISO that schedules in Texas, allows wind generation of 50 percent deviation from schedules. We heard that the New York ISO exempts intermittent renewable energy generators from regulation penalties and settles at real time prices. My understanding being that's real time spot residual market. We also heard that the PJM ISO settles at real time prices without penalty and further allows schedule changes up to 20 minutes before the hour. We heard that RTO West has applied to FERC to provide an eight year exemption on energy imbalance charges for wind energy. And we heard that on September 30th 2002, FERC approved an application by the Bonneville Power Administration to exempt wind generation from an imbalance penalty of 100 megawatts -- megawatt dollars per megawatt hour. And to allow a deviation to be charged at Bonneville's incremental cost plus 10 percent. The reason that we heard that these jurisdictions modified the imbalance tariff provisions, was most clearly stated in a quote from Bonneville Power Administration press release dated July 25th 2002.

And again quoting exactly from the transcript. It said, "The penalty in question is designed to encourage power plant operators to actually schedule the output of their generators, said Steve Wright, BPA Administrator. But wind generators cannot constantly predict with accuracy their output. So such a penalty would only discourage the development of wind projects." And that's the end of my quotation from what we heard at the original hearing.

I guess when I look at that, I come to this question that I want to put to you. Is it reasonable to suggest that there are a variety of methods used by different ISOs and RTOs that will recognize the uncertainties associated with scheduling wind, but at the same time provide reasonable opportunities for wind energy development? Is that a fair statement? You can handle this in different ways?

MR. PORTER: Yes. And that's definitely true. There are a variety of ways. And I think one of the things that you will see -- the difference being in how the compromise is achieved between recognizing the difficulties that the wind generators would have in scheduling, but also addressing the concerns of the other market participants that it -- that there is potential for cost shifting due to the introduction of wind generation if there is no -- nothing done to address those concerns at all. So it's a matter of balancing between those two concerns.

Q.518 - And item 8 represents your -- the approach that you would prefer to take for this province?

MR. PORTER: This is one of the -- one of the mechanisms that we have in place to provide opportunity for wind generators. Another one is that we do allow -- well, for all parties we allow schedules to be updated up to 30 minutes before a particular hour. Also for wind generators we have allowed in the Market Rules a mechanism whereby a wind developer can provide us with telemeter data about the potential output of a site. We would convert that and automatically update their dispatch information to help them avoid variance charges.

Q.519 - Okay.

MR. PORTER: But this is just another mechanism we have put in place that does recognize the diversity. We have a bit of a concern with the size of our system versus the potential size of the wind development in the region. We want to try and provide the opportunity, but without putting in place any kind of mechanism that we would have to go back and adjust later, because it's shifting costs to other parties as the level of wind development increases.

Q.520 - Okay.

MR. MARSHALL: One other point on that is that we by settling the variances at a market-based price that also removes the significant penalties that are in the system today, which was an issue in the previous hearing. So the combination of that with the telemeter data and the up front automatic scheduling updates, we think we have gone a long way towards alleviating the barriers to wind development.

Q.521 - I guess there is one question that arises when I review this though in my mind. Is this -- this deals with sharing variances. And presumably there is going to be a first wind generator in the province. Who do they share their variances with?

MR. PORTER: No one. This policy would be of no benefit to the first party. And if there was only one party this would not benefit. This was discussed with the wind developers at our technical conference December 13th.

Q.522 - So that --

MR. PORTER: And it was, you know, clearly everyone understands at that session that this is really motivation for further development and in diverse areas of the province, because -- and the region, because with greater diversity there is more likely to be variances that can be offset. But is of no benefit to the first party.

Q.523 - So the potential impact of this is some years out?

MR. MARSHALL: Well -- or if -- if Maritime Electric chose to take some type of network service and participants on the island chose to participate in this market, you could take the wind generation that exists there with the project in New Brunswick. So there are opportunities for this to occur sooner than a few years time. Depending upon what participants do in the marketplace.

Q.524 - And so I am clear what you are suggesting, there is somewhat akin to integrating the Maritime system and operating it as a single system?

MR. MARSHALL: Well that's possible. I am talking about today where Generation in New Brunswick supplies a lot of the load in Prince Edward Island.

Q.525 - Right.

MR. MARSHALL: The question is Maritime Electric, Summerside could become network customers -- could choose to become participants directly in the market subject to these rules. Then the generation that they control could also be scheduled and bid in. So that if that's the case, wind generation in the island could actually participate in this with the Grand Manan project in terms of sharing variances.

Q.526 - Wouldn't there be jurisdictional issues associated with that?

MR. MARSHALL: The jurisdictional issues? Possibly there may be on Prince Edward Island. Whether the regulators there agree or not agree. But the fact that our tariff -- there are no restrictions under this tariff at this point in time. We had discussion on that in the previous hearing. We were asked the question right up front whether Summerside could become a network customer and participate. And it's on the record that we agreed and provided the information related to their loads, they could participate under this tariff in terms of supply.

Q.527 - Would the Northern Maine areas and the Southern Maine areas that you supply also be able to enter into and become a part of the network in that way, rather than be supplied as they currently are?

MR. MARSHALL: If they -- if they chose to. And there is also provisions in the Market Rules for generation external to the system to register as generation in this market to supply such. If the wind generation on Prince Edward Island registered through to be dispatched into this market, it could happen and then be subject to this tariff opportunity.

Q.528 - This is something that you think is not very likely in the near future or is very likely in the near future?

MR. MARSHALL: Very likely, not likely? I would say it's speculative in terms of the time line that this will occur. I believe -- I believe that there will be more move towards a regional Maritime market. How fast it will occur, I am not sure. But I believe there are movements in that direction. And we believe that the Rules that are set up under the New Brunswick market and this tariff, you know, were a good base on which that could move forward. But how fast it will move is outside our control.

Q.529 - Thank you. I would like to move now to item 12 of your evidence. It's on page 34. And it is titled Generator Obligation for Special Protection Systems.

When I read this proposal under the section labeled "Reasoning" at line 17, I find the statement that "A generator that is tripped off line as a result of an SPS will not be subject to energy imbalance charges at that time, as the trip is a control action and is thus treated as a form of dispatch instruction."

And then when I flip the page and on page 35 look at line 11 and see that you want to add to schedule J of the OATT the words "The generator will not be compensated by the System Operator for costs incurred by the generator due to a special protection system trip."

It strikes me that those two statements are somewhat inconsistent. I'm wondering if you could explain that to me?

MR. PORTER: Certainly. I will talk about the -- on page 35 first, this is referring to costs such as if there is a certain amount of time required to bring the unit back on line, or if there happens to be any damage to the generator as a result of being tripped off line, or if there are opportunity costs as a result of being tripped off line, those types of costs are -- there is not to be compensation by the System Operator.

Q.530 - How do we know that? Or how does someone reading this document know that you are referring only to certain specific costs and not to the costs that you put in the reasoning as something that you would pay for or they would not be subject to energy imbalance charges?

MR. PORTER: I guess I would have to check the details in the market rules to see if it is covered there. But certainly if it was a concern we could add the appropriate wording to the tariff to address that issue.

Q.531 - Thank you.

MR. MARSHALL: I think the question here is that -- maybe the issue is -- it doesn't say it -- but the generator will not be compensated by the System Operator for costs. That means costs, any costs.

There is not a differentiation of one or another. It is any costs incurred by the generator. We are not going to provide and compensate them for any costs they incur.

Q.532 - So if I understand that correctly, then this would be a material increase in the risk that a generator with an SPS unit would have to endure to participate in the market.

Because there must be some finite probability that there will be this trip and these costs will occur, otherwise you wouldn't have this statement, is that right?

MR. PORTER: There is an increased risk, yes. I would say it is probably relatively small relative to other risks of the generator being tripped off line, such as a lightning strike on the generator leads or other issues.

There are several reasons obviously why a generator might end up being tripped off line. This would be just one small component of that.

Q.533 - Yes. I would like to carry on on this. But I guess I should refer you to the interrogatories that the Board put to you in reference to the SPS.

The first was -- I think this will be in exhibit A-3.

It was the first PUB IR, IR number 10. So under tab for the Public Utilities Board, IR number 10 is on page 14.

Your response to this first interrogatory, IR-10, indicated when I read it that high export levels on the MEPCO interface were a circumstance in which the SPS systems would be required.

And in that response it went on to say that the intent -- the installation of SPS will typically be required of all new generators.

Then we had an additional interrogatory that appears as IR-9 under the tab "PUB Additional". And it is at page 26 in that section. That response went on a little bit further to state that "Your intent is to require all new generators to provide SPS controls."

Now the difficulty I'm having here is that when I look at your proposed wording, it says that "The System Operator may require other special protection systems at certain sites. Special protection system requirements will be determined by the System Operator on a case-by-case basis."

My difficulty is that I look at that revised wording and suggest it seems a little bit misleading in the context of your response to the interrogatories.

I'm wondering if that is a fair assessment? Or am I missing something here?

MR. MARSHALL: I think we could qualify that and say we would require all generators if required. It is not the intent. And I guess I wrote that answer. So if it is misleading I will take the blame on that.

The intent is that we are not going to make absolutely every generator subject to SPS. Because there are some that cannot be. If a nuclear unit came on the system, there are issues with the Nuclear Safety Commission and others that you would not trip that type of unit off line.

So it does depend on the nature of the generator, its location on the system, the reasonable probability that it is dispatched and on and running and that it can adequately provide this service to the system.

Q.534 - Okay. What would be the typical cost for an SPS for a new generator?

MR. MARSHALL: The -- I don't have detailed costs. But I would estimate it is in the tens of thousands of dollars. It is not a million-dollar ticket. It is essentially the relay costs and communications costs to sense the tripping of the MEPCO line.

And then when that happens that is communicated directly to the generator. And then that control would trip the generator. So it is essentially the relay communications costs associated with that.

Q.535 - So that cost wouldn't likely represent a barrier to the entry of a generator? That's trivial in the cost of a generation plant?

MR. MARSHALL: That is correct.

Q.536 - So I guess my next question is who is going to benefit from the SPS devices that you are putting on these generators? Is it going to be the system as a whole? Or is it going to be the exporters, noting that you mentioned the MEPCO line?

MR. MARSHALL: The system as a whole.

Q.537 - Okay. And I assume then that is because it enhances the reliability of the system?

MR. MARSHALL: It enhances the reliability of the system. It actually improves the -- as we responded in Additional IR-9, it actually improves the transfer capacity across interconnections that wouldn't exist if you didn't have the SPS's. And it means that there would not be transmission that would be saleable to customers.

And if that transmission was not saleable to customers in the market, it means that the transmission rates for all of the other customers would go up in order to recover the revenue requirement. So it provides benefits to all participants in the market.

Q.538 - But we recover the revenue requirement now, don't we?

MR. MARSHALL: Yes. But as an individual customer -- we recover the revenue requirement. But if the usage on the system -- and I just for the whole Board -- the tariff rate is calculated based on the revenue requirement in dollars divided by the usage in the denominator.

If the revenue requirement doesn't change but the usage in the denominator goes down, when you divide by a smaller number the rate goes up.

So all customers in the system would be charged a higher tariff rate. They gain -- everybody gains benefits from the use of SPS's to maximize utilization of the system.

Q.539 - So if I understand this correctly, if we didn't have the new generators put on these special protection systems, in order to maintain the reliability that we want in the province, you would have to reduce the exports on the MEPCO line, is that correct?

MR. MARSHALL: If all existing SPS's were removed from the system and you did not have continued SPS's --

Q.540 - Not in reference to anything existing. We are talking about new here. If you did not require new generators to put on SPS systems, would that -- you are telling me that to maintain the reliability of service within New

Brunswick, that would limit the exports on the MEPCO line, not certainly with respect to where they are now, but with respect to what you might hope they will be in the future.

Is that the understanding that I'm getting, or to have?

MR. MARSHALL: That is possible. If the existing generators that have the SPS controls on them today were off on maintenance or not available, and new generators came on that did not have the capability, then it would be necessary at times to limit flows across that line.

Q.541 - So the system as a whole benefits from it in the context of a potential upward pressure on rates if we don't have them to facilitate exports on the MEPCO line.

I guess what I'm trying to get at is here, it seems to me that you can put this in the system pot, in which case to me, if it is a system-wide thing, why wouldn't it all be paid for on an uplift charge? Because it is a system-wide benefit.

Or you can put this in the pot that relates to the people who are profiting from the exports, which will be the generators presumably, and get them to pay for it. I'm wondering why we are sticking this charge on the new generators?

MR. MARSHALL: The example in question here is the MEPCO tie where SPS'S clearly do increase the transfer capacity across that line. This tariff is a long-term tariff for utilization of the system.

As we go forward there may be a requirement for new generators coming on, depending upon where they locate in the system. Relative to just their connection to the system they may overload lines or do things. They may be subject to an SPS to get onto the system.

This is a general reliability issue in terms of minimizing costs. Because if you did not require an SPS, then it may be necessary to actually build additional transmission, which again is not in the interests of customers because it would increase the cost of transmission.

The objective here is to provide transmission service to customers at the minimum cost, with the greatest flexibility to operate the system in the most reliable manner to provide service.

And the issue is simply to be able to, rather than just dispatch a generator down when something occurs, it is necessary to have an SPS that senses it instantly and trips the generator off line. This is an optimal utilization of the system opportunity for all customers.

Q.542 - And so do I take from that that you think it would be best paid for by -- socialized by all the systems built into the tariff?

Your argument would seem to support that rather than having the new generators pay for it, that is all.

MR. MARSHALL: If the issue is in terms of the cost, the trivial amount of the cost that we talked about to put the actual relay and controls in place, if the Board deems that that shouldn't be paid by the generator but should be charged and socialized across the system, we are prepared to go there.

But the issue is we believe that for reliable operation of the system and optimum utilization of the system for customers, we need to have the right to say, you have to have a special protection system.

Q.543 - Right. Then again the problem is it is not just the cost of the system. It is your exempting the system for any costs incurred when this trip system goes and causes, in your own words, some damage to their plant.

It really seems to create a large risk uncertainty for any generator who would want to hook up to your system to simply say well, you have got -- we will buy the equipment for you, we will hook it on, but if it operates it is your problem, is what you seem to be saying in your revised wording, where you won't compensate for any costs due to a trip.

That seems to me to create a real barrier for market entry into the market, all to really, what seems to me, do not much more than facilitate exports on the MEPCO tie line. But I'm looking for something that would convince me otherwise here.

MR. PORTER: As I mentioned earlier, there are a number of reasons why a generator might be tripped off line. And the generator has to be prepared for that. They would obviously want it to be infrequent. We would want it to be infrequent.

But it's going to happen on occasion. There may or may not be some costs incurred, that should be insignificant. They would need to do what they can to mitigate those costs.

And I think that we are talking about a very rare occurrence if that is -- this one additional instance whereby there might be tripped off line. I can't myself see that as being a barrier to them building a generator or coming -- connecting onto the system.

Q.544 - And then what you seem to be saying is the costs aren't awfully significant. Then why is it an issue for you in that we have to have it in the tariff, revised wording of the tariff?

MR. PORTER: It is something that was noted in the market rules for clarity, so we don't get into this debate, so someone some day doesn't come along and say, it's only X number of dollars, but I would like to get reimbursed for that and come in.

It's just a matter of clarification so we all understand up front and we don't get into that type of debate with the generator owner at some point in the future.

MR. SOLLOWS: That is fine. Thanks.

BY THE CHAIRMAN:

CHAIRMAN: Just following up on what Mr. Marshall said, what about Genco's generators, with the exception of Lepreau? Are they -- do they have these devices, all the generating plant?

MR. MARSHALL: Not all. But all the large ones do.

CHAIRMAN: That begs the question, why don't they all have it?

MR. MARSHALL: Well, take an example. I do not believe Grand Lake has a special protection system, given the size of it and what it can actually do and how it operates.

So the units that have special protection systems are the hydro units at Mactaquac and Beechwood, the Coleson Cove, Belledune, Dalhousie, the units that are generally on the system that are going to be there and operating. So it provides basic operation.

CHAIRMAN: Okay.

MR. MARSHALL: So size is an issue, okay, related to it.

CHAIRMAN: I'm coming at it from a regulator's point of view. And too many years in regulating auto insurance, thank you very much. And the test was a discriminatory policy on the part of the insurer or the rates being discriminatory. And that is where I'm coming from on this.

If you require all new generators to have it, and you are not limiting it to a certain capacity, it is just -- it is blanket, then are you not discriminating against the new ones in favor of certain of Genco's assets, that because of their size, you are not requiring them to have it. Certainly if there is a technical reason like with Point Lepreau, then we appreciate that.

However, go ahead.

MR. PORTER: Ownership would not be an issue in determining whether or not an SPS would be required. It would be issues such as the size of the unit, in the case of a nuclear unit the implications of tripping it off line, those types of things and what the benefits are. But ownership is a non-issue in that evaluation.

CHAIRMAN: Well, all right then. Let me ask the last question before our break, which is would you be able to reword the tariff so that anybody looking at it would say well, I have got a small windmill, and that is less than X megawatts capacity, and therefore I won't have to put in an SPS.

In other words, the tariff is specific. And you as the SO or anybody else cannot discriminate as between one applicant or another, because the rules are there and easy for everybody to read?

MR. MARSHALL: Yes. Size is an issue. So we could put in a limitation on size to say that all generators greater than -- you know, we need some number to look at.

Let's say all generators greater than 20 megawatts or 50 megawatts are -- this may be required. And if you are smaller than this you are exempt.

CHAIRMAN: Did I hear --

MR. MARSHALL: But there may be a situation --

CHAIRMAN: -- this may be required?

MR. MARSHALL: This may be -- we do not say this is absolutely mandatory. Depending upon the location in the system and the requirement, it may be required.

CHAIRMAN: Okay. What I guess I'm saying is that from a regulator's point of view, if there is a discretion left with the system operator that he or she could impose a cost on one generator and not another, then that gives you the ability to discriminate between them.

And when you have a nondiscriminatory tariff the rules are crystal-clear. And people know whether they comply or they don't. You have to have an immense amount of discretion in running the system, without question.

But in something like this, if you could write it so that -- you know, you don't have to exercise your discretion at all. It is there. It is in black and white. Everybody knows the rules of the game.

Anyway I will just leave that. And we will take our break and be back in 15.

(Recess - 11:07 a.m. - 11:22 a.m.)

CHAIRMAN: Any preliminary matters?

MR. WHELLY: Nothing, Mr. Chair.

CHAIRMAN: Nobody else? Okay. Commissioner Dumont had a question as Mr. Sollows is through with that subject matter, and --

MR. DUMONT: We were talking about this SPS system. Who would be the first one to be tripped off and in what order? Which generator would be tripped off first? Is it according to size?

MR. MARSHALL: I think it's in the actual response to PUB 12 or 10. Not the additional one but the original PUB 10.

What normally is done is the operator in the control room looks at what the requirement is. There is sort of a schedule based on the loading on the New England tie, what the requirement is for the magnitude of the trip, and then would look at all of the units that have SPS capability, and then based on those would select what are the units that have the least possible disruption to the system or to any impact on those parties.

So if there was energy coming in from Hydro-Quebec it would be to maybe look at the DC coming in and ramp it back, it would be to look at the hydro units first because you don't lose any energy at all, and then you can reschedule and do that, and then go to what are the other units.

And when you get into the thermal units, then you would look at which units are then on the margin and which units are actually -- you know, may be actually associated with the export sale, then if the -- you have to trip that -- those units to back up what is on the line, energy was actually allocated with it.

So it's a number of factors but really they look at least disruption, least potential problems, least cost to everybody in the system.

MR. DUMONT: So realistically it would be always the same ones going down?

MR. MARSHALL: Today it could be depending upon circumstances in the system. For instance -- but in the -- depending upon certain times of the year or what the loading is or what opportunities there are that cause disruption, it would change from to time.

MR. DUMONT: Okay. Suppose you would be cutting back let's say Mactaquac or Beechwood which has the cheapest power supposedly --

MR. MARSHALL: But they would not -- at times when Mactaquac and Beechwood are running normally, if you stop them from generating they don't lose any water. The water stays behind the dam and then you get to use -- they don't lose any energy. So there is no cost associated with that.

But if you were tripping Mactaquac or Beechwood in the spring time when there is extremely high run off and they are all running and you can't capture that water, then you lose that zero cost. So at that point you look at what are the marginal units on the system against cost.

MR. DUMONT: But still, you know, it would always almost be the same ones that you do trip off, depending on normal circumstances, you know. I'm not talking about spring run offs or -- in the normal operating sense, it would always be almost the same generators that would be tripping off first.

MR. PORTER: There is one other component in the evaluation of which units would be armed or selected to be tripped if required and that is matching up the total amount selected with the amount of export that's on the tie, and trying to get that relatively close. So it's not strictly a pecking order of top to bottom in the same order. You would also have to look at, okay, if you add the first two units in the pecking order and the fourth unit, does that give you the right number of megawatts. So that's another aspect of the evaluation that makes it tough to just say, here is the formula for selecting the units.

MR. DUMONT: So it could be different at different times?

MR. PORTER: Yes.

MR. DUMONT: Thank you. That's all I have for now.

Q.545 - Thank you. I want to go to item 14 now. It's on page 38 of the evidence A-2. And it deals with credit support and deposits to be for two months' transactions, a proposal I guess to increase the deposit requirements from what it is currently, one month of exposure, to two months of exposure for market participants, this being the money that they deposit with the system operator.

The rationale that is given for the change is that the lag in billing -- there is a lag in your billing and collections. But my concern is that this increasing the deposit requirement might act as a barrier to market entry.

So what I would like to know is how much money are we talking about for a 100 megawatt generator under the current tariff and under your proposed revision?

MR. MARSHALL: The requirement is for one months' worth of the transmission transaction value. So for 100 megawatts, the total current obligation under the tariff, if it was a point to point reservation for 100 megawatts, the combination of the tariffs and schedule 1 and 2 and schedule 7 or 8 would be about $29 a kilowatt year. So $29 times 100 megawatts would be 2.9 million dollars. Divided by 12 that's around $240,000.

Q.546 - So in that case you would be increasing it from $240,000 that they would have to have sort of paid in advance to 480,000?

MR. MARSHALL: That's correct.

Q.547 - It seems to me to be a fairly substantial amount of money and I'm wondering if you couldn't deal with this issue by reducing the lag in billing and collections?

MR. MARSHALL: We currently bill on the fifth day following the end of the month and we want collections by the 20th day, the fact is somebody has utilized the tariff by the time they don't pay and there is a default and we try to get it they could be two months gone by. So we -- the real risk is that we are out two months of revenue before we can actually cut them off.

Q.548 - How is this covered in other -- by other system operators in New England or does the FERC pro forma tariff deal with it all? What do other tariffs do?

MR. PORTER: The FERC pro forma is the one month. In terms of whether or not other transmission providers have modified the requirements, I don't know.

Q.549 - So this is a deviation from the FERC pro forma?

MR. MARSHALL: I believe it's consistent with the Market Rules in Ontario and other markets.

Q.550 - I guess I would like to now go to item 15 which is page 40. This is titled "Parties to Connection Agreement" and I'm looking at the revised wording. It starts "Load", and the wording seems to imply to me that this is focused on interruptible loads. So I just need a clarification. Is this dealing with all loads or loads that are interruptible or somehow dispatchable?

MR. PORTER: We are looking at item 15, page 40, lines 25 to 30?

Q.551 - Well that's the current wording.

MR. PORTER: Yes.

Q.552 - And I guess the question and the new wording is on the bottom of the following page, and I'm just trying to sort out what you need in terms of connection agreements with loads.

MR. PORTER: This is pertaining to load facilities for which a transmission customer has requested network service. So it may be interruptible, it may be firm. Most times it would be firm but it's both. It's generic.

Q.553 - And so when you say the change in here changing the words "to each facility owner from the eligible customer".

MR. PORTER: Yes. I will explain what that -- that's where the transmission customer is the party that comes to us and requests transmission service. That may or may not be the actual owner of the facility. It could be a marketer, it could be NB Power, customer service and distribution that says I want to take network service for this facility, but in the case of the agreement that needs to be signed between the transmitter, the counter-party to that needs to be the owner. If the transmission customer is someone other than the owner that wouldn't be appropriate. It needs to be with the owner -- the actual owner of the facility as opposed to the transmission customer.

Q.554 - Fine. Thank you. On with item 16. This deals with a modification to the tariffs that would allow you to address intra-hour behaviour which you described as the potential for market participants to lean on the system within the hour, not coming to their schedule on time at the start of the hour and deviating from it throughout the hour.

I guess based on what I have heard I think last week and my reading of this, is this becomes a problem for you really most obviously if we remove the penalty from energy imbalance. Is that right?

MR. MARSHALL: If the energy imbalance -- the energy imbalance penalty today is an incentive to stay on schedule. But even then to stay on schedule, you can stay on schedule by being out high 50 megawatts at the start of the hour and low 50 megawatts at the end of the hour you are on schedule over the hour. But you have actually utilized 50 megawatts worth of automatic generation control resources in the system during those ten minute intervals. That's really what this is aimed for.

Q.555 - So do we have some examples of where this has been a problem? Do we have some evidence that this has been a problem in I guess the six months the market has been open now?

MR. MARSHALL: This we responded to an interrogatory on the history of the interface with Nova Scotia in terms of where this is an issue today as to how much generation control is going on in New Brunswick to compensate for variance of the area control error at the Nova Scotia interface. That has been an issue over a number of years and was an issue in the previous hearing.

Q.556 - And I guess -- and I might have this wrong, so I want you to clarify it. I understood or at least I thought I heard that since the market opened in October you had found that Nova Scotia had come much closer to schedule and they were not such big issues with respect to imbalance and the scheduling issue at that connection, and I know we had -- this issue was dealt with in the last tariff. You I think had negotiated a separate agreement with them. Is that agreement not being honoured or is there --

MR. MARSHALL: The agreement to settle the interface for energy imbalance is being honoured. The issue here is intrahour. There still are significant variations intrahour. However, the behaviour has improved. The amount of movement of generators in the New Brunswick market to handle deviations at the Nova Scotia interface have reduced by about 25 percent before and after October

1st.

Q.557 - But in your opinion there is still an undue cost shifting occurring. They are basically cost shifting because Nova Scotia is not controlling their system accurately enough?

MR. MARSHALL: There are errors that come across the Nova Scotia system into New Brunswick. We have to monitor as the Maritime control area operator for the MEPCO interface. We then have to do additional control to offset that in order to keep the MEPCO interface in line. Our concern is that today currently the loads in New Brunswick, PEI -- or New Brunswick, PEI and Northern Maine essentially pay for this frequency control -- regulation frequency control service.

Nova Scotia are to provide their own within their market place but it spills over into New Brunswick and we then have to compensate. So 25 percent of the actual AGC pulses and movements of the New Brunswick generators are to compensate for Nova Scotia variances.

Q.558 - Perhaps we need a DC link between Nova Scotia and New Brunswick?

MR. MARSHALL: Or a common Maritime market, and then all controlled together to the MEPCO tie. That's another alternative.

Q.559 - Fair enough. Okay. I understand that I think pretty well. And, Mr. Chairman, did you want that or do you want me to -- so I guess that finishes all of my questions. Thank you very much. You have been very helpful, very illuminating.

BY MR. NELSON:

Q.560 - Mr. Marshall, what percentage of your total revenue is going to come from the distribution company within New Brunswick?

MR. MARSHALL: About 75 percent.

Q.561 - About 75 percent. And from the export end of it?

MR. MARSHALL: About 20 -- currently I guess probably about 22 or 23 percent. There is around two or three percent other parties.

Q.562 - And you based your budget on -- just going back, you know, to the budget. You based your budget on how many megawatts per year, around 3,000, 3,100?

MR. MARSHALL: The tariff is based on the billing determinates that were in the original tariff hearing. I believe that's around 2,100 megawatts of coincident peak load for in-province load and 720 megawatts of long-term firm point to point reservations which would be to go to external areas. And then there was a miscellaneous amount of short-term export revenues which amounted to about 4' or $5 million.

So the load in the system is not much different than what it was in that test year that was put before the Board in the last hearing.

Q.563 - So if the -- we will call it the sales go down and the number of megawatts per year goes down then the tariff will go up?

MR. MARSHALL: The -- if the sales go down there will be a shortfall in revenue. We would have to come back to this Board in order to change the rates in order for the tariff to go up. The tariff does not automatically go up.

Q.564 - So basically what it is then that's automatic billing per year? I mean, that amount is automatic? In order for you to get your budget, meet your budget that number is used as an automatic billing number, whether the volume goes up or down?

MR. MARSHALL: No. The way the tariff is structured right now if the volume goes up we would actually gain a bit of revenue. Now against the System Operator revenue we are dealing with only schedule 1 in the tariff. So we would gain a bit of revenue above the $6.3 million that's forecast, if the loads go a little higher. If the loads do not materialize we would get a little bit less than the $6.3 million and we would have to manage that accordingly under the current arrangement.

There is no automatic true-up at the end for us to be assured that we get $6.3 million. So based on performance we would have to come back to this Board to change the tariff.

And as far as the other schedules in the tariff we bill and collect the money. We turn around and we pay that money back through to NB Transco and to WPS based on the ratio of their revenue requirements. So if the load goes down they take less revenue as well, and then it would flow through to affect whatever their rate of return is. So that's a risk that they take at this current point in time.

MR. NELSON: Thank you.

BY THE CHAIRMAN:

CHAIRMAN: Before the break I requested that you ensure the Board get access to your OASIS system, the full nine yards. And during the break I wanted to put a little bit more on the public record and get your comment on it concerning that whole thing.

If we look at the information that is provided on public websites of system operators in other jurisdictions, and in particular New England, they seem to make a great effort to disclose as much information as possible. This helps the public and the regulator by reducing information asymmetry in the market place and is generally held to be necessary for economically efficient market outcomes.

When we look at the information provided on the NBSO website, there seems to be relatively less emphasis on public disclosure.

Would you care to explain your philosophy regarding publication of system information? For example, what is involved in posting the schedule to an actual interchange flows of the New Brunswick interconnections on a real time and a historical basis?

MR. MARSHALL: I will just make a comment that Mr. Porter can give you a bit more detail on where everything is.

Currently I generally agree with the concept that is raised, that publication of information is beneficial to the market and players so that they actually have the information in order to interact in the market place. And that's part of providing and facilitating a competitive market, which is our mandate under the Act.

The issue with some of the information at this point in time is that prior to December 1st it was based on actual costs of NB Genco's operation, and that's confidential information subject to commercial value that

that shouldn't be published.

The other part is we do have under the Market Rules a number of things that we are required to publish. Most of those things are available to the market participants at this time under the secure portion of the website. Most of those documents all are being translated and prepared and so as soon as they are finished through translation they will be moved to the public side. So we are in the process of getting a lot of that up. So we are in a building stage at this point in time and it is our intent to have most of that information and everything that's in the Market Rules in terms of the requirement for publication available on the public portion of the website.

CHAIRMAN: Now can you do that in a format similar to that which is used by ISO New England to facilitate that compilation and analysis?

MR. MARSHALL: We could look at that. I'm not sure exactly the detailed format that it's in right at this point in time. As I say, what we intend to do is have it available. Most of it, the schedules and things that are available to customers that go on, are in a way that are uploadable and downloadable for those parties to interface with the systems. So in that extent we would attempt to make the data available that it could be gained and utilized by customers.

But to say we are specifically to get the data in exactly the same format as ISO New England, I don't know that it is or isn't, or whether it necessarily should be. And that's an issue. What I would like to say is that our people are preparing a lot of that now and we certainly would take that under the advisement of the market advisory committee and the participants in the market to say what form should this be in in order to be the most utilized, and we would provide it in that form.

CHAIRMAN: All right. Well from our perspective it's as I said in reference to accounting matters earlier on, it's awfully nice to be able to compare apples to apples and oranges to oranges. And I hope that the market advisory committee will consider what the regulators had to say about that when they do approach that.

Now I have no further questions. Mr. Whelly, do you have any re-direct.

MR. WHELLY: Very brief, Mr. Chair.

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

Q.565 - First for Mr. Marshall. I refer you to exhibit A-3. The answers to interrogatories from PUB IR-16. Now my question relates specifically to the $300,000 cap in retained earnings. And you were asked earlier how you arrived at the $300,0000 figure and you made reference to the cost of a hearing before the PUB.

Looking at the response in B, are there other uses to which this cap would be put other than the periodic appearance before the PUB?

MR. MARSHALL: It would reduce the requirement for working capital and interest on working capital. It would provide for some degree of money related to an unforeseen contingency. And currently in our budget, there is no line item provision for contingencies in the budget. I might say even on that basis, the budget currently has $108,000 for insurance in it. That was done up in January. We have since got the bills for insurance and so for the director's and liabilities insurance, it has come in about 21', $22,000 higher than what was budgeted.

CHAIRMAN: I don't regulate insurance anymore, Mr. Marshall.

MR. MARSHALL: I guess the point, it may offset the costs of the annual report, Mr. Chairman.

Q.566 - Thank you. As well for Mr. Marshall, you and Mr. Lavigne answered a number of questions relating to the accounting treatments of the roughly $2 million in expenses that have been transferred from Transco to the SO. At the end of that series of questions, you were asked -- and this by the way, appears at page 248 of the transcript of this hearing. And the question number is 340.

And the question was, "If the budget for the SO and Transco approved at the original OATT hearing had been on the basis of what we know now, are you saying that the budget for the SO would be $2 million higher and the budget for Transco would be $2 million lower?" And the answer you gave was "Yes."

Now I noticed the questioner used the term "budget". And I wasn't sure whether you were referring to revenue, expenses, both and I wonder if you could clarify.

MR. MARSHALL: Yes, I think the issue is not budget. My understanding the revenue requirement for schedule 1 in the tariff, if we had all the information at that time we have today, schedule 1 would have been set at $2 million higher than it currently is in the tariff and schedule 7, 8 and attachment 8, so the revenue requirement for Transco would have been $2 million less.

The budget for Transco wouldn't change. There is a cost shifting issue. We are seconding all of those parties. Transco gets miscellaneous revenue associated with it. But the revenue requirement for the services that it sells changes by the $2 million.

Q.567 - And then moving to an item from this morning relating to the SPS that may be required. What factors would you consider in determining whether a particular new generator should or should not have an SPS?

MR. MARSHALL: The size of the unit, the safety issues related to the type of the unit and the ability to withstand a trip. Its particular location on the system relative to the transmission that interconnects it to the system. I think those are the kinds of things. And then what impact it has relative to the overall reliable operation of the system.

Q.568 - Leaving aside the second item you mentioned, the safety related to the type of generator, is there some interplay between the various factors. So for example, you mentioned size as one factor and location in another. Is size -- would the size you consider be different in one location than in another?

In other words, would you think in one location 20 megawatts was a reasonable limit, but if the unit had been somewhere else you would have been satisfied if the unit was smaller than 40 megawatts but it did not need an SPS? Is my question clear?

MR. MARSHALL: I think there is an interplay between size and location. If a generator was located at the lower voltage levels and the 69 or 138 kv on a radio line or on effect it would have to have controls to be able to trip off automatically with the system.

It depends on whether or not it could cause congestion in an area if it remained on and another line went off in the system. So in that situation, rather than build an extra transmission line, you would want to be able to trip that generator to preserve the integrity of the system.

So if it is connected at lower voltage levels, the size -- a smaller size may be required. If it's connected at the 345 kv, then size is not so much of an issue. The larger the unit you can handle it.

MR. WHELLY: That is all I had, Mr. Chair.

CHAIRMAN: Thank you. Gentlemen, thank you for your testimony. It has been very helpful. And this is an ongoing process, as we all know, and I would like you to convey the Board's -- this panel's appreciation to your staff and as well to the Secretary of the Board and her staff. Each time you appear in front of us, it becomes easier to follow the evidence and I even noticed that we have got sequential page numbering and all that sort of thing. It makes the day go much better, I must say.

Anyway, again, thank you for your participation. And I guess we are down now to summation. And Mr. Whelly and other parties, do you want to break now for lunch and come back at say 2:00? Or do you want to make it 2:30? I just want you to have enough time to put your thoughts together.

MR. WHELLY: 2:00 would be sufficient for me, Mr. Chair.

CHAIRMAN: Anybody else? Silence is acquiesence. We will reconvene at 2:00 then for summation.

(Recess - 12:00 p.m. - 2:00 p.m.)

CHAIRMAN: Good afternoon. Any preliminary matters?

MR. WHELLY: I have none, Mr. Chair.

CHAIRMAN: No others? Fine. Go ahead, Mr. Whelly.

MR. WHELLY: Thank you. Mr. Chair and Commissioners, as you know I am here wearing two hats, representing both the System Operator and Transco. So I want to deal first with issues specifically related to the System Operator that are identified in the application, and then I will move on to address some aspects of the Transco budgets that had been presented to you.

When Mr. Marshall started his presentation here last week he identified four areas where he thought there may be a controversy, or at least that he thought that they may receive some attention. And he was right. They did receive attention. And they are four items that I am going to touch on today.

I'm also going to touch on four others that received a fair amount of questioning, and I just want to address a few issues with respect to each of them.

So the first four items I will address are the residual monthly cost recovery, the second will be the cap on self-supply of ancillary services, the third will be intra-hour behaviour and the fourth will be standards of conduct.

And then the four other items I will touch on will be the automatic increase at half the rate of CPI, then the accumulation of retained earnings to $300,000, credit support and deposits and then the generator obligation for special protection systems.

Now before I move on to to the individual items, just so that I don't keep repeating myself on the way through, there is a key point that must be remembered all the way through my comments and that is all of these proposals were considered by the Market Advisory Committee. The Market Advisory Committee whose participants -- whose members represent participants in the industry have reviewed these and agreed that these proposals should be put before you. So when you have a concern of the impact of a particular proposal there is a filter that has already been in place, and while you have to apply your own judgment, there has already been some feedback from the industry implicit in the response of the Market Advisory Committee.

So looking at the residual monthly cost recovery, I had the sense from the questioning that there really didn't seem to be much discomfort with the thought that these expenses or benefits had to be dealt with. They are there, they are a fact of life and somehow the SO has to find a way to deal with them.

There was an issue over who gets to share in what may be the outcome, either positive or negative, but it's my submission that the response of the witnesses show that their approach does not create any inequity. There are differences in approach on these matters among different system operators. There is no universal approach. And it's my submission that the NBSO has come up with an approach here that is reasonable.

One thing we have to keep in mind here is that the SO does have to account for the recoveries or for whatever expenses there are, and those reports are published and available to the participants.

And finally the history to date has been that there are more benefits than there are expenses. So this is not -- this is not a slush fund to bury expenses. This is a way of taking these residual items and seeing they get either given back to the market participants or that they -- that the market participants pay to cover the expenses. Particularly important because the SO is operating on a not-for-profit basis.

The cap on ancillary services. This Board is well aware of the genesis for this issue. It is this Board that wanted an investigation done to determine whether there was a way to develop a market for ancillary services in New Brunswick. And there is no reason why today a supplier couldn't enter the market and offer these services. The issue today is that it may not be particularly attractive given the transition phase we are in right now. So this is a mechanism that in our submission increases the likelihood of someone coming into the market and offering those services.

There is an RFP process underway. It's being supervised by this Board and the Board will see the results of that. In terms of the cap itself, when it is being addressed after the RFP process has moved forward, remember that the Market Advisory Committee will make a recommendation to the NBSO Board of Directors before the Board of Directors makes a decision on the cap.

So we don't have the SO acting independently in setting this cap. There is going to be feedback from the participants and presumably if the market participants do not see any benefit in having a cap put in place they will advise the NBSO Board. It's our submission that this is a proposal that does have an upside for the market in New Brunswick and could result in reduced costs.

Intra-hour behaviour. As you have heard this is an issue with Nova Scotia. It does -- it is a mechanism to deal with the energy imbalances that appear on the border between New Brunswick and Nova Scotia. Let's remember that Nova Scotia can very easily avoid these costs. All they have to do is make sure that those energy imbalances aren't there at the border. If they manage their own system and get rid of the energy imbalances there will be no cost.

However, if Nova Scotia wants New Brunswick to provide this facility to them, New Brunswick is quite happy to do it. The only response is if you want the service please pay for it. And that's the basis for this proposal. Other markets are starting to address this issue. It is being recognized that one hour averaging doesn't really reflect what is going on. And as we know from the testimony that we have heard today and you have heard before, the decisions are being made by the System

Operator on a less than minute by minute basis to ensure the system is reliable. So trying to break it up into one hour chunks doesn't really reflect reality.

Standards of conduct. In my submission this is a perception issue. Very clearly there was a reason why Transco -- well not Transco -- why NB Power had to sign a code of conduct, and that arose out of the nature of that particular beast. The System Operator is an independent operator. It does not have the types of conflicts that concern FERC and which motivated FERC to call for a code of conduct.

The SO isn't saying that it's not going to abide by the principles implicit in the code of conduct. The SO is merely saying it's not needed because it's otherwise taken care of in the general principles related to the SO and in other provisions in the tariff. And one of the responses to the interrogatories submitted by this Board, your Interrogatory 13, addressed that issue.

Now if this Board feels that a code should still be signed by the SO, the SO is prepared to sign a code. However, the code that exists at present isn't appropriate because it wasn't drafted for signing by a stand-alone system operator. So a special code would have to be written for the SO if the Board felt it was appropriate that there be one.

Now I will mention because we shouldn't forget that there is a special provision here for WPS. The SO agrees that WPS does not have sufficient transmission assets to separate functions to the degree required by the existing code of conduct. So the SO supports special treatment for WPS as set out in the proposal.

The automatic rate increase. Now I would ask the Board to keep this proposal in context. If inflation is taking place, if the CPI increase is two percent, this would allow a one percent increase, and as Mr. Marshall testified that reflects $63,000 in a year in an increase. We know that 96 percent of the expenses of the SO are subject to inflationary pressures. The largest expense that the SO has is a labour expense. So there is no doubt as we sit here today we all know the SO's costs are going to go up, and the question merely is how do we deal with those increases on a going forward basis?

An increase at one-half the rate of the CPI in my submission has an automatic built in pressure for management to control its expenses. If CPI is at two percent and they are only getting one percent a year, they are going to be squeezed at the end of year 1, they are going to be more squeezed at the end of year 2 and even more squeezed at the end of year 3. It's a cumulative effect that if their expenses increase at the rate of the Consumer Price Index then they are going to get further behind the eight ball.

So there is a mechanism to ensure that the SO continues to be managed efficiently.

Now the SO is not trying to avoid Board supervision as was indicated in the testimony. If the Board wants the SO to come back on a regular basis whether needed or not, if the SO can cover its expenses with these automatic increases but the Board still wants the SO to appear and justify its rates on an intermittent basis, the SO is certainly prepared to do that. And I believe it was the public Intervenor that asked the question whether once every three years.

CHAIRMAN: Now, Mr. Whelly, is there anything in the Legislation that allows the Board to have a -- require a hearing in front of it by the SO?

MR. WHELLY: I think there are two mechanisms. One mechanism could be just on the terms of the basis of the decision that you give at this time, that you could as part of the decision insert a qualification or condition that the SO had to return.

Independent of that, Section 128 of the Electricity

Act seems to be the authority that gives the Board the right to direct that an inquiry be made into certain events. Now I have looked at this and there is -- I shouldn't -- I hate to say this -- but the wording is a little bit convoluted in that it talks about the Board having a right to look into something it has a right to look into, if I paraphrase the Legislation.

I think the clearer course of conduct would be for the Board to set a deadline in a decision now. But I think that Section 128 is subject to the interpretation that the Board can require the SO to come back.

CHAIRMAN: Okay. There is one other thing that has been -- especially since this weekend when I read the advertisement of the NEB's review of the route for the second tie line into the States that was in the local press. It's going to occur in St. Stephen I believe, tossing back and forth in my mind.

And I'm not asking you to answer this today, but I do think as we work through the new Electricity Act Legislation and the scheme of regulation and the market place itself, that we should probably schedule in the not too distant future an opportunity for the public Intervenor and Board staff and counsel, et cetera, to sit down and take a look at the provisions.

If I might, our first general rate increase application from NB Power Corporation as it then was in the early '90s gave the Board's approach to setting just and reasonable rates. And part of setting just and reasonable rates is to ensure that the costs that drive those rates are appropriate.

And the Legislation certainly from that controversial section 156 has yet to be proclaimed. It talks about reasonable -- or prudently incurred, et cetera, et cetera, et cetera. So I look at the tie line with the US and I realize it's totally in the discretion of the SO as to whether or not that tie line is necessary for the New Brunswick system.

But a review of its construction costs, et cetera, is that to look at in advance of the construction of that line to ensure that it is being done and not gold plated as we say in the regulatory business? Is that not an appropriate role or position for the Board to take?

And I think that plus some other things should be investigated in the future. I just wanted to put that on the public record now. I would be interested now and/or later for comments from any of the parties that might be interested.

I do know that in the Market Design Committee there were proposals on the table and withdrawn, et cetera, concerning putting a cap on it from the point of view of no project under 40 million will have to appear before the Board, and that was withdrawn.

But I'm not talking about the actual decision of the construction of the asset. I'm simply talking about the costs of that.

Now again you twice in this hearing have characterized the Board having an overview on the call for proposals function. My reading of the Legislation for whatever it is worth simply means that we look at the process put forth by Transco and/or the SO as to how the proposals would be called, whether it's fair and appropriate. And that's the end of our jurisdiction when it comes to that call for proposals.

So then the call for proposals goes out and the SO would have to comply with whatever procedure we had approved. But we don't sit in any role in actually the awarding of the construction or anything else like that.

So these are all questions that I think we should address in the future. Sorry to interrupt your summation and get us all off track, but carry on, sir.

MR. WHELLY: No, I appreciate the comments and I will relay them back to my client and we can go forward and address how that could be handled.

I was just in any event moving to my next topic which was the accumulation of retained earnings to a cap of $300,000. Once again I would invite the Board to consider that in the context of the entire operation of the NBSO. A $300,000 total of retained earnings would represents slightly more than 4 percent of the annual expense budget. It is --

CHAIRMAN: Yes. I will interrupt again, Mr. Whelly. Would that not be more aptly characterized as being a $300,000 contingency fund? You wouldn't have retained earnings in a nonprofit organization.

MR. WHELLY: I think you are probably correct.

CHAIRMAN: Okay. Fair enough.

MR. WHELLY: In other organizations with which I have been involved they are in fact not for profits. They are in fact entitled that way.

And in fact when you listen to testimony this morning of Mr. Marshall as to the use of those funds, that is exactly what it is for. It is there as a contingency against future expenses of some kind or another.

Moving on then to credit support and the increased deposit for two months transactions, what is clear is that the current system exposes the SO to a credit risk for two months transactions. And obviously there was some concern we saw this morning in question on this matter.

Particularly I think the concern was based on the burden it may place on the participants in the market. The billing cycle that exists in part is a reflection of the Tariff and the Market Rules.

There are items in the Tariff and Market Rules that if, when you interpret them, it is intended they be billed monthly. So trying to move to a two-week cycle can create a structural problem with the tariff and the Market Rules.

Beyond that, I'm sure you all recognize that if you change the billing cycle there is an administrative cost. And particularly when you have an organization that is rather thin on the ground, as the NBSO is, changing that cycle can't be absorbed easily.

I think as well that we have to keep in mind the nature of the security that is given today. Right now there is a requirement that one month's deposit be given. The NBSO isn't sitting on a bunch of cash deposits. Its customers have provided letters of credit.

And when you realize that, okay, there is a letter of credit sitting there that doesn't have a great cost in the scheme of things, and then realize the transmission costs are only a small percentage of the total cost of electricity. And then we are talking about one extra a month.

We are sort of talking about one-twelfth of one-tenth of -- so you get down to, you know, .008 of the percent of the total cost. It is a low number. So that is the amount of the deposit. So then multiply that by the cost of the letter of credit which is another percentage.

And finally this is one where I will mention the market participants were represented on MAC. They approved this and did not have a difficulty with it. So it is our submission that this doesn't create an undue burden for entry into this market.

Now I will move to the generator obligation for special protection systems. Now two issues seem to have come out of the questions on this. One is whether the cost should be paid by new generators or should be socialized, and secondly whether there shouldn't be some defined limit on the discretion of the SO in order to ensure that new participants are treated the same as old participants in this market.

Now for the first one I would ask the Commissioners to keep in mind what we have now. What we have now is a reliable and robust transmission system. Presumably that was paid for by the users of that system over the last number of years.

So if we now have a new generator arise and wants to connect to that system and enjoy the benefits of that system, isn't it fair that that new generator be asked to pay a small incremental amount to provide its support for the reliability of the system.

So it is not -- as we heard from the estimation of the cost, it is not a large expense. And it is my submission that it is a fair burden for somebody coming on and hooking onto a system that is already robust and reliable. It is not as if we are making new generators pay for shortfalls that existed in the past.

We are just asking them to assist in ensuring that the system we have now continues to operate well and that they pay their fair cost for that.

Now the second issue was the issue of the discretion of the SO. And we heard there are a number of factors that determine on whether an SPS is appropriate for a new generator. The one that was mentioned most often was size.

But size is not a stand-alone consideration as Mr. Marshall explained. Depending on the circumstances, the type of generator, where it is, the line it is connecting into, the amount -- or sorry, the size of the generator, they all have to be considered by the SO.

Now it is my submission that this is something that is properly delegated to the SO in its absolute discretion, and that it should be able to decide whether new generators should install an SPS, keeping in mind the SO already has tremendous discretion in terms of the operation of this system.

So this is just another factor. And this SO is independent. It is not going to favor any particular generator. But it is going to try to provide a consistent approach to protect the reliability of the system.

We submit that this is a logical way to deal with this. If a particular generator is unhappy with the result, that generator has the right to make a complaint to this Board. And this Board can become involved.

That takes me to the end of the specific proposals that I wanted to comment on. And I have very brief comments on the budget overall. We are not seeking a rate increase. We are here today merely trying to slice the pie in different pieces.

The rates that we are talking about in total equal the rates that were approved -- or should say the required revenue that is being sought is the same required revenue that was approved by this Board a few years ago.

WPS's revenue remains the same as the required revenue approved last fall. There is a shifting among categories.

Now there were questions on where the reduction of revenue showed up on the Transco statements. And it seemed to me we got a little mixed up in changes in revenue and transfers of expenses.

And it wasn't helped by the fact that there are secondment and services agreements and the fact that Transco continues to report the expense of those employees, but they have an offsetting revenue item.

So it makes the picture a little confusing from an accounting perspective sometimes. But the bottom line here is that roughly $2 million has moved into schedule 1. Transco will not have that money. The SO will have that money. And other amounts, schedule H and other schedules, the revenues will be reduced.

CHAIRMAN: Mr. Whelly, one of the difficulties is that we are all new at this. And frankly that kind of complaint, which I guess I initiated, but the Commissioners also had difficulty with, that can be overcome in the future by sitting down between staff of Transco and the SO and Board staff and coming up with a minimum set of filing requirements. And that would lay those things out so that we won't have that confusion in the future.

MR. WHELLY: There were some questions on budget variances as well as compared to the original OATT. Now I'm certain that the Board recognizes that the original budget was based on -- very much on a concept.

And what we have reported to this Board are the results of actual operations and how they have actually worked out. There are differences.

But it is my submission that the witnesses provided explanations for what the differences were. And they are not so unusual that they should cause the Board to second guess the decisions as made before in terms of the revenue requirement.

This Board did approve for Transco a revenue requirement and an approved rate of return on equity. And regular reports have been filed by Transco with this Board, albeit it on a confidential basis.

But nevertheless the results what we saw filed as part of this hearing show that Transco's returns have not exceeded the returns that were set by the Board.

We have put before the Board copies of the agreements for provisions of services to the SO by Transco and by other NB Power related companies to Transco.

As you will see in all of those agreements, the basis of the agreements is cost recovery. They specifically state that they are not intended to reflect cost-shifting. And the SO believes, in the contracts that it has signed, that reasonable prices are being paid. I think they are particularly pleased with their lease.

This brings me nearly to the end of my presentation. But there are a couple of items I should mention. As you know, this application includes rates for Transco and WPS. And many of the Interrogatories required follow-up information from both of those companies.

The SO received very good cooperation from both and was able to turn around responses very quickly because of that cooperation.

At the start of the hearing I neglected to identify Mr. Roherty as co-counsel with me for NBSO. But there are others, as the Chairman noted this morning, who are key to these matters moving forward properly. And it is staff in the regulatory department that the process really works as the Board hopes. It is not the lawyers who are sitting here that makes sure that it takes place.

So Marg Tracy and Chantal St. Pierre, together with the support of their personnel, are the ones who deserve commendation for that.

And although it is unusual, I also want to thank one of the other lawyers in the room. Mr. Hyslop was appointed very late in this proceeding. And there was the possibility that the hearings may have had to be adjourned.

But although Mr. Hyslop always made it clear that he wouldn't do anything that would preclude him from fulfilling his mandate, he did take steps to ensure that he could move this process forward so that we could start our hearing on time.

The Market Advisory Committee had asked the SO to attempt to have the revisions in place by April 1st. And the System Operator tried to comply. We recognize that is not going to happen.

However, the SO does believe that whatever changes are approved they should probably have -- not probably have, but they should have an effective date of the 1st of the month, whatever the month is.

The billing cycles are based on monthly cycles. So we would ask that. And of course the Board can issue, can and should issue its decision, so that there is an effective date.

We recognize as well --

CHAIRMAN: Excuse me. On that basis, as I always used to ask the insurers, how long will it take with your systems to bring those changes into effect? In other words if we put it out in the last week of the month are you in trouble? Give us a little guidance on that.

MR. WHELLY: I asked that question myself at noon hour. And I was told that that is not an issue, that they can switch over the systems with just a couple of days notice.

There are also the customers and participants of the market that have to be considered as well, because they will make decisions based on what this Board decides.

So we would suggest, for example, and I will be ever positive and hopeful, that if this Board were going to decide in April to allow a May 1st effective date, that the decision should be rendered by April 22nd which is a Friday. And that would provide sufficient time.

If the Board -- the reason -- I should tell you the reason the NBSO can be ready to change over in a couple of days is because they have been a little presumptuous, and that is that they have prepared systems on the assumption that -- on the assumption that the Board approves the material as presented.

If there is significant movement away from the proposals then it may take a little bit longer. It's hard to estimate how much longer it would take. And that's about as much guidance as I can give.

I wish to thank the Chair and the Commissioners for their attention and I would ask the Board to approve the proposed revisions to the open access transmission tariff. And I would be pleased to answer any questions any of you may have.

CHAIRMAN: Thank you, Mr. Whelly. We will give you an opportunity to comment on the Intervenor's comments in a few minutes. You know, I must say that when I keep hearing about the SO being described as independent and he and Transco are both represented by the same counsel, it causes one to take second thought. But I appreciate. Mr. MacDougall?

MR. MACDOUGALL; Thank you, Mr. Chair. Good afternoon, Mr. Chair, Commissioners.

WPS Canada Generation is one of the transmitters in New Brunswick and as a member of the Market Advisory Committee supports the NBSO's application as filed with the Board and recommends that the Board approve the application, the tariff revisions and the rates as filed.

WPS would like however to briefly comment on two issues related to ancillary services. First the proposed cap on self-supply, and second the SO's response to certain information requests posed by the Northern Maine Independent System Operator.

WPS would also like to briefly comment on the NBSO's proposal regarding the pricing of energy and balance service considering certain of the questions that were raised earlier today by the Board.

With regard to the first issue, that being the proposed cap on ancillary self-supply, WPS supports the SO's application. During questions raised in cross-examination by various parties, the SO made it clear that the concept of a cap is to create an impetus for a market for ancillary services to develop in New Brunswick. And more importantly the use of an RFP process combined with a cap is for the purpose of obtaining lower prices for ancillary services.

The open access transmission tariff currently sets prices for ancillary services which will effectively act as an upper bound which would be available to all users of the tariff. An open, vibrant market for ancillary services will only act to bring these costs down for the benefit of all load in the province. Considering that Disco, the distribution company, as the primary transmission customer, is the elephant in the room in this regard, a limit on self-supply which would be applicable to the arrangements between Disco and Genco can only serve to assist in developing a vibrant market for ancillary services in New Brunswick.

Furthermore, as Mr. Marshall indicated in response to a question from Commissioner Sollows, this will help to create true market values for ancillary services in the province.

Accordingly, WPS's position is that the Board should at a minimum approve the concept of the cap and the related proposed tariff wording changes, subject however to any further oversight it may consider necessary regarding actual specifics of the ultimate cap.

Now to move to the second issue. This is the issue raised in NMISA IR's 3 and 4. WPS does not believe it is appropriate for the Board to approve any change to the methodology for determining the allocation of capacity based ancillary services for external system operators. The Board approved the non-coincident peak, or NCP method, that's now part of the tariff as a part of the initial tariff proceeding. This was a proceeding in which the NMISA participated.

The hypothetical approach raised in the NBSO's additional information filed in response to NMISA IR's 3 and 4 would see a new allocation method based on 12 CP, or 12 coincident peak, being used for external system operators, that being Northern Maine and PEI, serving load in their jurisdictions. Then would be the method used for either load in New Brunswick or for external load in such jurisdictions who were purchasing capacity based ancillary services directly from the NBSO. This WPS submits would be inconsistent and discriminatory treatment of similarly situate users of the New Brunswick open access transmission tariff.

As Mr. Porter noted at page 155 of the transcript, and I would like to quote this, and this was in response to a WPS question regarding full non-discriminatory treatment in the tariff. Yes, that is correct, and I will go beyond. I mean, does the principle of non-discriminatory access, and in my mind one of the best ways to use that is to use consistent methodologies. And there are some cases where for some particular reason different parties need to be treated differently. But in terms of administering a tariff it does make it very difficult to at the same time ensure that it is a non-discriminatory implementation of the tariff if you used different methodologies.

WPS submits that this is the case and in fact that it would not be possible to claim the tariff was being administered on a non-discriminatory basis if the hypothetical approach posed in response to NMISA IR's 3 and 4 was adopted.

And again I note this is not a proposal by the NBSO but rather a hypothetical approach in response to certain Interrogatories that were raised in this proceeding.

Furthermore, as indicated in the NBSO's response to PUB Additional IR-2, use of the 12 CP method for 2004 for external system operators as opposed to the Board approved NCP approach, showed an increased allocation of capacity based ancillary services to Prince Edward Island and a reduction to Northern Maine.

And Mr. Porter confirmed that this was only a single sample year comparison and that a change in the nature of consumption of a particular load, or the addition of a new load in either of the jurisdictions could -- and again I quote -- "change that relationship between the NCP data and the 12 CP data, thereby changing what the results would be under each of the two methods".

Mr. Porter acknowledged that in the period immediately prior to this Board approving the current open access transmission tariff which is based on an NCP basis, that a CP basis had been used, coincident peak base. And this was specifically changed to the current Board approved NCP basis for the allocation of capacity based ancillary services to New Brunswick, Northern Maine and Prince Edward Island loads. To now change this methodology back to the use of CP for some loads and NCP for others would clearly be inappropriate.

With respect to the issue of energy imbalance service, WPS is the market representative on the Market Advisory Committee and notes that the Market Advisory Committee unanimously agreed with the current proposal before the Board.

The agreed approach would remove the penalty nature of the pricing and allow full cost recovery to the SO through use of the final hourly marginal cost. This is a proper price for the New Brunswick market as it is the actual price in the market. Any suggested use of a Keswick Node price would not be indicative of New Brunswick market prices. As ISO Keswick Node prices would generally be higher, settlement at that price would give the SO a windfall. That windfall would then have to be socialized back to the market through the residual monthly cost or RMC recovery method. But as this is based on reservations it would not be shared out appropriately to those who contributed to this unnecessary windfall.

As noted by Mr. Marshall, the proposal before this Board is consistent with the Market Rules promulgated by the Minister of Energy and is seen by the market as a whole as a positive development. Mr. Marshall also indicated that the market advisory committee was continuing to review the issue of the timing of availability of the final hourly marginal cost information.

However, although the back may subsequently come forward with a further position on this issue, the market is firmly in support at this time of moving from a penalty provision to final hourly marginal cost pricing.

CHAIRMAN: Mr. MacDougall, if I might interrupt?

MR. MACDOUGALL: Certainly, Mr. Chair.

CHAIRMAN: As was evident from Commissioner Sollows' questioning this morning, one of the concerns that the Board had and may still have is that the basic reason that was given to us of the penalty nature in the first hearing was gaming of the system.

Your client presumably next to the System Operator and Transco has a greater knowledge of the system in this province today. And is your client in agreement with Mr. Marshall's belief that there are sufficient market rules and checks and balances available to him in his role to be able to overcome any possible gaming of the system?

MR. MACDOUGALL: Well, Mr. Chair, you were prescient because that was the section I was just coming to and I will directly answer your question. Yes, he is. WPS does believe that the Market Rules that are going to be in place now are sufficient and we would also like to note that proposal before the Board was in two parts.

It was 1, to remove the penalty aspect to allow it to be the final hourly marginal clearing price, so that there would be no windfall or no shifting of costs, but the parties would pay the appropriate market price of the highest cost generator on the system.

But secondly the SO has maintained the position that it's going to continue to watch the market, so that if generation or load is off on its balance it will be watching that market and it is maintaining a position that it will come back and look at that. What the market sees this as is a very positive forward looking position where we are not immediately setting a penalty to guide market behaviour. What we are hoping is that market behaviour works. It works in accordance with the proper pricing signal. If it doesn't work there is a chance to come back and look at it.

But the market through the Market Advisory Committee and certainly WPS sees this as actually a very positive forward looking point, and in fact I believe from WPS's perspective, and although I can't speak for others, but this was one of the issues on which the Market Advisory Committee really wanted to get in place and thought it was a very positive development by the SO to remove this penalty provision.

If issues do occur in the market place the NBSO has in its proposal said it will deal with them on a case by case basis. And that is seen as a very positive viewpoint by I believe the market as a whole and hopefully others who follow will indicate that that is the case.

And just so that the Board is aware, we were not going to speak to this issue and did only raise it because some of Commissioner Sollows' questions did indicate that the Board may have a concern. We would like to be very clear that the NBSO's proposal is very strongly supported in this regard. It's being seen as a positive thing in the market.

So that took my thunder away because that was my closing. So that works very well, Mr. Chair.

Mr. Whelly did an excellent job of stating what the position of the NBSO is. Obviously some of those items are directly attributable to WPS, but Mr. Whelly went through those, so I will not. And on those points there was no cross-examination or information requests or further information required from the Board. So I will just leave it that.

Thank you, Mr. Chair.

CHAIRMAN: Good. Thank you, Mr. MacDougall.

MR. MACDOUGALL: Thank you, Mr. Chairman.

CHAIRMAN: Now at least this morning Canadian Manufacturers & Exporters weren't here, nor Mr. Daly. So does the Irving group have any remarks they wish to make?

MR. PAPPAS: Yes, Mr. Chairman, just a few very brief remarks to add to the record.

CHAIRMAN: We always like to have presenters get up front here.

MR. PAPPAS: Okay.

CHAIRMAN: So we can see the white of their eyes.

MR. PAPPAS: Thank you. I will be sure to keep these brief.

First our companies welcome the opportunity to consult with and participate in the development of the self-generator rate proposal. Secondly, we feel the rate structure as proposed by the SO is an accurate representation of the actual costs for the services received. And finally, Irving Paper Limited, Irving Pulp & Paper Limited, and JD Irving Limited support the proposed revision of the wording to the rates in Attachment H.

Thank you very much.

CHAIRMAN: Good. Thank you, sir. Sorry to make you make you move. But we had no idea it was going to be so short.

Mr. Morrison?

MR. MORRISON: Good afternoon, Chairman, Commissioners. Thank you for the opportunity to address you this afternoon. Let me begin by saying that Disco, as we are sometimes known, generally supports the application being put forward by the NBSO. And in particular, the proposal to settle energy imbalance on the final hourly marginal cost.

Despite Mr. MacDougall's characterization of us as the elephant in the room, we generally agree with everything Mr. MacDougall said in his presentation. And in fact, he addressed all the points I wanted to make on that issue. Knowing that when you're the elephant, you're also a very large target, I would like to only add or reemphasize two points on the clearing of energy imbalance.

And that is as he said, it is a market based approach. It is supported by the Market Advisory Committee. It is in keeping with the recommendations of the Market Design Committee and moving to a price based energy imbalance settling methodology. And it is in the best interest of the ratepayers of New Brunswick as well.

Unlike generators, when you talk about generators, they have an interest or could have an interest in gaming the system, other transmission customers like Disco really doesn't have an opportunity to game the system. But yet would be subject to settlement of energy imbalance on a penalty provision would only increase costs to the ratepayers ultimately.

And that is all I really have to say on that issue. The only other issue I would like to address, and that is the issue of the cap on self-supplied, on ancillary services.

I will start by saying that Disco is not necessarily opposed to some form of market in ancillary services. However, it is concerned about what the magnitude of any self-supplied cap may be and the ramifications it may have on Disco and ultimately its customers.

The problem is at this point we really have no idea what form the proposed cap is going to take. In short, the request to have this Board approve a cap on self-supply of ancillary services, I would submit is immature -- sorry not immature -- is premature.

We know from the evidence of Mr. Marshall, that there are two key criteria that are being proposed for the formulation of this cap. The first criteria is the availability of capacity -- ancillary service capacity in the marketplace. And the second criteria would be the historical purchase of ancillary service by market participants.

We know that this RFP process has been launched, but the information on one of those key criteria, that is the capacity in the marketplace, is not yet known. Without this information, it is impossible for a transmission customer like Disco to determine what the ramifications will be, particularly the magnitude of the reduction in self-supply. We just have no way of determining what that proposed cap will be.

Now last Tuesday or Wednesday, I believe it was Wednesday, under questioning, Mr. Marshall suggested that this proposed cap would be a sliver of the market. The problem is that we don't know whether this is going to be a sliver or a great big chunk. Now if it turns out only to be a sliver, it may very well be that my client would have no objection or no complaint with the cap. However, it cannot make that determination at this time because it just doesn't know.

The application or I believe it was the response to one of the interrogatories from the PUB and again reiterated by Mr. Marshall and Mr. Porter last week, is that there is a whole process laid out for determination of this cap. As I understand it, first the market information must be gathered, what is the capacity out there. The data and the proposal must then be considered by the Market Advisory Committee. The Market Advisory Committee will then make a recommendation to the NBSO Board, and it's only then will there be a decision by the NBSO Board. And it is only then that we will know what the cap really is.

I would suggest that by asking this Board to approve a cap now before you know what that cap is, before the process is complete, is akin to asking you to buy a pig in a poke. How can you possibly determine if this ancillary services cap is in the public interest if you don't know what the cap is.

So it's my submission in this regard, Mr. Chairman and Commissioners, that the proposed cap request is premature. I suggest that the appropriate way to proceed is to allow the process to unfold, and that no decision should be made until the NBSO is in a position to bring a concrete and not an abstract proposal to this Board for its consideration.

And those are all my submissions.

MR. NELSON: Mr. Morrison, you have a contract -- Disco has a contract with Generation for all the generation for the next five years?

MR. MORRISON: There is a contract between Genco and Disco for all the heritage assets but it is for in excess of five years, Commissioner Nelson. I believe it is a 25 year term at this point, I believe.

MR. NELSON: Thank you.

CHAIRMAN: Mr. Morrison, I have but one question. When does the large target move into the sights of the Board?

MR. MORRISON: Mr. Chairman, the bigger they are, the harder they fall. But I expect that we will be lumbering in very shortly.

CHAIRMAN: Okay. I won't push you any further. Thank you, Mr. Morrison. Mr. Belcher?

MR. BELCHER: Good afternoon. And thank you for this opportunity. I went ahead and typed up my notes. Because last proceeding I think my southern drawl didn't come across too good on the transcript. So --

CHAIRMAN: Well, it certainly didn't bother us.

MR. BELCHER: And I might add that the Northern Maine ISA is so independent we don't even have an attorney let alone share one.

MR. SOLLOWS: A state of mind.

CHAIRMAN: Now that is lean and mean.

MR. BELCHER: Of course our load is less than some of the customers in New Brunswick.

Again thank you for this opportunity. My comments relate to the following topics: 1) Allocation of Ancillary Services for loads external to New Brunswick. 2) Initiate Residual Monthly Cost Settlement. 3) Mechanism to Limit Self-Supply of Ancillary Services. 4) Intra-Hour Behaviour. 5) Standards of Conduct. 6) The $300,000 Reserve Build Up. And 7) Settle Energy Imbalance at Market Prices.

And I don't want to be redundant. But the ISA is not a member of the Market Advisory Committee.

Number 1. Allocation of Ancillary Services for total loads external to New Brunswick. The New Brunswick Power Corporation has a representative on the NMISA Board of Directors because NB Power is essential to the efficient operation of the Northern Maine Market and the information must flow between the two organizations. Decisions made in New Brunswick can have significant impacts on Northern Maine. The NBSO has indicated that they are willing to amend the tariff to allocate revenue requirements for Ancillary Services for external loads utilizing a 12 CP Allocation methodology to address concerns regarding the sensitivity of electricity markets.

The ISA now seeks the application of the 12 CP Allocation methodology to rates for Ancillary Services for external loads for the following reasons:

First or a. Promotes Market Efficiency. The 12 CP allocation is more efficient to administer than the current Net NCP allocation because it does not require a forecast at the beginning of the month that must be trued-up at the end of the month. For the entire year, each market participant will know its responsibility towards the region's Ancillary Services requirement. This permits the market participant to plan and properly commit existing and future resources to the maximum benefit. Additionally, the norther Maine market operates on a bid system (similar to what NBSO has proposed in this proceeding) with a Tariff capping the price, which is based on the proxy unit. That proxy unit was approved by the Commission in the prior proceeding.

By using the 12 CP method, the ISA can attract its bids more efficiently since its responsibility would be fixed on a monthly basis and not subject to a retroactive change. I would also note that net NCP's are more difficult to forecast than CP's. For the region as a whole, Ancillary Services requirements are static, and the ISA therefore believes that its Ancillary Services requirements should also be static.

Finally, with respect to administration, the MPS system is not as sophisticated as the NB Power system. It takes us approximately 6 business days to go out and read 20 meters to calculate our net NCP. Using the 12 CP method, the 12 CP responsibility can be determined at the conclusion of each power year in a relatively short time using the hourly loads archived in a database.

The second reason. We feel it promotes market transparency. In order for the ISA to self supply some of its Ancillary Services, a translation from net NCP based responsibility has to occur to determine the actual responsibility in megawatts. Net NCP is a billing determinant, not a direct amount of generation. Net NCP is not coincident with the actual load thus a ratio has to be calculated between total load and the net NCP to determine the relationship that a generator has to output to meet its net NCP responsibility.

Under the 12 CP method, there is a direct relationship between generation output and the responsibility for your share of ancillary services.

Third reason. Eliminate seams. The U.S. Federal Energy Regulatory Commission today encourages policies designed to reduce and eliminate seams between adjacent markets. By amending the tariff to allow for a 12 CP allocation of external loads, there would be fewer differences between the markets.

Also, I believe there would be fewer steps for both the NBSO and the NMISA to settle at the end of the month. I know this because I do it.

Fourth reason. This is the proper resource allocation for external markets. It is my understanding that one significant rationale for the using the net NCP method for the NB Market was to ensure that large transmission customers with generation "behind the fence" would be properly credited for their internal generation.

For individual customers, this is a reasonable rate design because there is only one metering point and the load lacks diversity. However, this principle does not apply to the ISA since it has four metering points with a transmission and distribution system behind the interface. The sum of the net NCP loads is determined by taking the maximum demands of each transmission substation. These maximum demands re not always coincident thus the diversity of a load is not accounted for, overstating the NMISA's contribution to the Maritimes Ancillary service requirements.

Moreover, the NMISA's internal generation is not even credited to the load because their maximums are taken from the substation rather than the interface.

Industry accepted rate design principles use NCP allocation for distribution costs. The distribution system is the low voltage local feeds. FERC's approved methodology to allocate production and transmission fixed costs is the 12 CP methodology because it recognizes the responsibility of each customer at the time of each monthly peak. FERC has determined that Production and Transmission resource planning is done on system peaks not the sum of peak individual loads regardless of when they occurred. Otherwise, production and transmission systems would be grossly overbuilt.

And finally on this issue is cost shifting. WPS states that they believe that using this 12 CP allocation would be discriminatory. The ISA believes that it is nondiscriminatory because under the approach the ISA pays the same costs, same rates and based on our proportional share. In fact in a prior proceeding the Commission adopted in schedule 4 a special provision for us to settle our markets.

As demonstrated in NBSO's response to the ISA data request, the adoption of the 12 CP allocation for external loads would not result in cost shifting. Also, because the Commission approved the costing of ancillary services based upon proxy units to reflect market costs, the Commission has essentially adopted a long run marginal pricing. Industry accepted marginal cost pricing properly allocates costs for production and transmission based on peak responsibility, commonly known as the Peaker Methodology. Because costs are allocated based on load responsibility at the time of system peaks for production and transmission costs, by definition cost shifting did not occur because all load is paying its proportionate share.

Item 2 for the ISA's comments. And to be redundant I remind you that we are not a MAC member.

The NMISA supports the payback of the RMC. However, the ISA does not support the payback based upon the NBSO's proposed methodology since this methodology does not allocate the revenue in the same manner that the excess was collected. The NBS proposes to pass back the revenues in proportion to transmission billing determinants. The ISA opposes this methodology. The NBSO and NMISA settle monthly for energy exchanged on its interface. Upon completion of the monthly settlement with the NBSO, NMISA then settles with its market participants pursuant to their Northern Maine Market Rules.

Market Participants in Northern Maine purchase energy from NB Power Genco. Genco sells energy as a bundled product that includes wheeling and energy. Thus, Genco is the transmission customer. Purchases for energy are settled on an hourly basis. Each business day, the ISA submits to the NBSO a Day Ahead Schedule that shows the anticipated hourly exchanges on the interface for the next day. As the hour approaches, the participant can adjust their hourly schedule up to a half hour prior to the hour to compensate for load changes. This adjustment is considered the final schedule.

Pursuant to Schedule 4 of the OATT, the difference between the Final Schedule and the Actual Load for the hour is settled using a formula. Schedule 4 works as follows: When the difference is within plus or minus 2 megawatts, referred to as inside the band, marginal price or Final Hour Marginal Cost are used to settle that amount.

For differences greater than plus or minus 2 megawatts, referred to as outside the band, the penalty rate is used for under scheduled energy and $18 a megawatt hour is used for over scheduled energy.

Now let's "follow the money." The ISA pays cost for energy inside the band and at penalty rates for energy outside the band. Since September 1, 2004, costs associated with inside the band were wired to the NBSO and costs outside the band were paid directly to NB Genco.

From October 1, 2003, I believe when the tariff was implemented, all costs were sent to the NB Power Corporation. It is my understanding that NBSO paid Genco for all energy at marginal cost, a Final Hour marginal cost. Now they propose to return the over collection the difference between the penalty rate and marginal cost for under scheduled energy and the difference between $18 per megawatt hour and marginal costs for over scheduled energy. Thus, NB power Corporation will be paid for the difference for which they have already been compensated. Not only do they collect the difference between costs and penalty rates, they collect it twice. This is unjust and unreasonable.

The RMC should be returned in a manner reciprocal to the manner in which it was paid in. As shown in the table below, the amount of money is significant. It's $666,626 Canadian. This represents more than 75 percent of the ISA's annual purchased power costs.

The ISA is a non-profit organization and would return the money to the market participants based on how each participant paid in. Basically, we would perform a rebill and subtract their original costs from the revised cost, calculate an adjustment and distribute the pay back.

This is an industry standard and is done today between the NBSO and the ISA when there are revisions to marginal costs or other settlement factors. It is usually done at the end of the month.

I have included the table here to show the monthly changes that would occur.

My third item for comments is the Mechanism to Limit Self-Supply of Ancillaries. The ISA supports this proposal if the 90 percent is not product specific, but rather 90 percent of the overall Ancillary Services responsibility. For instance, the ISA self supplies its 10 minute and 30 minute non spinning reserve, but purchases its full responsibility of regulation, frequency control, and 10 minute spinning. Thus, our purchases of ancillary services are greater than 10 percent of the total requirement. By applying the 90 percent requirement to each product, our market will have a negative impact. Market Participants have made investments to self supply some of their ancillary services.

Additionally, the ISA tariff allows for the self supply of ancillary services pursuant to the FERC proforma tariff. This limitation would create a market seam.

Intra-Hour Behaviour. As pointed out during cross- examination at the hearing, this charge would not pertain to customers purchasing regulation because they would be paying twice. The ISA concurs.

Standards of Conduct. I appreciate WPS's position regarding size. In fact, FERC has granted waivers for many small companies for many aspects of the OATT compliance, but does not generally exempt them, if ever, from the code of conduct requirements. FERC expects that employees that share responsibilities across departments conduct themselves in the spirit of the code no different than executives at the top of an organizational pyramid who have managers reporting to them from the transmission and generation departments.

The ISA does have concerns regarding WPS's Transmission's lien of questions in the proceeding regarding the 12 CP allocation for external loads. By the tone of the questions, and now from their comments, it appears that WPS Transmission does not support the 12 CP allocation for external loads. I gather from NB Power Transmissions' silence on the issue that they don't oppose the allocation. The question is: why would a transmission company oppose the allocation for ancillary services that are production related not transmission related unless they were acting on behalf of the production side of the business?

One of the major reasons for the development of the

Code of Conduct was to keep the transmission area from sharing information with the generation or marketing area to gain competitive advantages.

Number 6. $300,00 Reserve Build Up. The ISA is offering this information. It is commenting for informational purposes. The ISA's annual budget ranges from $600,000 to $680,000. That's U.S. We are a small operation. There is three staff members. One item in our budget is non-current working capital that our lenders required us to accumulate. The ISA collected $50,000 per year for five years to achieve a $250,000 cash working capital reserve. This amount is critical for two reasons.

First, our lenders required us to demonstrate that our tariff both recovered our costs and produced a healthy balance sheet to address potential volatility and capital requirements common in this industry.

Secondly, for the ISA to be independent, it cannot be financially dependent on its members. I believe the $300,000 is conservative, considering the NBSO'S approximate $7 million budget. The budget should include a line item for accumulating a cash working capital reserve.

FERC has approved this approach as a prudent mechanism for capturing this revenue requirement item, and has established an industry standard formula to account for the lag of revenues relative to expenses.

And finally, Settle Energy Imbalance at Market Prices. The ISA supports the use of Final Hour Marginal Cost of settling energy imbalance because it provides a better price signal for actual shortage or excess cost to society. Additionally, this type of market price, more competitors will be encouraged to engage in the market. By pricing the imbalance at FHMC, marginal prices for energy based bids into the market will approach true marginal costs because if the bid price is not done correctly then the unit won't be dispatched. Additionally, with this type of market price, more competitors will be encouraged to engage in the market because they will be able to predict prices with more consistency.

However, due to the lack of competitors, the Commission should consider a interim cap to offer stability. But I do believe that there is a cap on the bid price.

Also I would like to add that the penalty rate that's in schedule 4 was an interim provision into the market rules and the infrastructure could be implemented. Now that the SO has done so and the capability is there I feel it should be implemented as to the reasons stated above.

And as far as gaming is concerned when you -- in any true market where prices are at marginal prices, how can one game it, even if they are leaning on the market, or if they are providing excess?

They are not actually gaming. The only real concern there is your reliability issues because they are not following the schedule. In a true economic sense they are just not gaming, they are leaning on it.

And finally, it was nine years ago approximately that I was offered -- handed the FERC proforma tariff and was told to implement it for a utility. And it amazes me that everywhere I go it doesn't change much. And that must be because it is working.

Most markets I have seen, all the production-related ancillary services have been removed from the tariff and have been put into the market rules. The reason for that is because its production-related and these market rules will consistently change as the market emerges. But the tariff consistently stays the same for the transmission service because it is important that it is consistent across all different markets. And it is a precious document for the industry to work. And I have found that in all three different markets that I have been involved in, the transition from a regulated to a market-based market.

That is my comments. Sorry they were too long.

CHAIRMAN: Thank you, Mr. Belcher. Mr. Young?

MR. YOUNG: Would you like me to begin, Mr. Chairman, or wait a moment?

Good afternoon, Mr. Chairman and Commissioners. My name is Dana Young. I am an employee of Saint John Energy and represent the three Municipal Utilities. I have been in attendance throughout this hearing on behalf of the three municipal utilities in New Brunswick - Perth-Andover Electric Light Commission, Edmndston Energy and Saint John Energy.

I would like to begin by thanking the Board for the opportunity to participate in this process and voice our position on the Open Access Transmission Tariff Review brought before the Board by the NB System Operator.

The municipal utilities became formal intervenors in this proceeding primarily for the purpose of addressing the implications that this application might have on our customers, the ratepayers of our communities. We believe that the implications of your decision will equally affect all ratepayers in New Brunswick.

The municipal utilities were supportive of the original OATT hearing application as applied for by NB Power on June 21st 2002, and we continued that support with the OATT revisions of June 15, 2004.

Under the Electricity Act proclaimed on October 1st 2004, the OATT has been transferred from NB Power to the NB System OPerator. Currently the NBSO has brought forward a number of revisions to the terms and conditions of the OATT and proposed changes to the rate schedules.

We are pleased with the NBSO having performed stakeholder consultation through a technical conference on December 13th 2004 and through ongoing Market Advisory Committee (MAC) meetings. We feel that our current positive position on most of the issues that the applicant has presented to the Board is due to the consultation achieved at the MAC meetings.

The first issue I would like to comment on is the proposed changes to the OATT terms and conditions. We find that the proposed changes align the OATT with the market rules, update the wording consistently with FERC Order 888A Pro FOrma Tariff and address most of the concerns of the wind developers.

We are concerned that an important item such as limiting or capping the self-supply of ancillaries, as indicated on page 13 of the NBSO's presentation titled

"Items with Potential Controversy" was not thoroughly reviewed by the MAC and that the NBSO has not brought forward the cap percentage they are recommending. Our issue is that currently NB Disco is our standard offer supplier. If the NBSO sets a cap at 80 percent or 60 percent, than an RFP will go out for the ancillary service that could be more than NB Disco is currently paying. Otherwise these ancillaries would have already bid into the market. The increase in cost to NB Disco will flow through to their customers through a future rate increase as a flow through by NB Disco.

The other issue with regard to ancillaries could hypothetically, as a worst case scenario, be that a transmission customer has entered into a long term power supply agreement, including ancillary capacity. The through a forced ancillary cap system, they purchase 20 to 40 percent of their ancillaries from the NBSO. They could in fact be double paying for these ancillaries. This would cause a definite upward pressure on our rates as soon as the cap is implemented.

We are also concerned that Standard of Conduct, indicated on page 13 of their presentation "Items with Potential Controversy" is applicable for transmission companies and should also be applicable to the overseer, NBSO. The Standard of Conduct should be viewed as a program to ensure ethical business conduct and be an awareness and educational tool for those conducting business. The perception of fairplay is important to all customers.

The second issue I would like to comment on is the proposed changes to OATT rate schedules. We find that the proposed changes will align Schedule 1 with NBSO's cost of service tables, will implement a self generator rate proposal in favor of self-generators and does include WPS revenue requirements in the revised rate schedules.

The issue we have is with NBSO, their response to Public Intervenor IR-5, page 6 of the responses to interrogatories and also listed in the NBSO's presentation on page 9, item 9 as "self-generation rate proposal" developed with industrial self-generators, states that the transfer of added costs between Schedules 1 to 7 will amount to a cost increase to NB Disco for standard network service of about 2.8 percent. Because transmission service makes up only about 4.5 percent of the cost for NB Disco to supply standard offer service, the potential effect on a future rate increase is about .13 percent. This would result in a future increase in standard offer service cost which would flow through to our customers.

This could raise residential rates from the proposed 9.7 percent to 9.83 percent, even without considering the additional cost concerns mentioned above with reference to the ancillary cap.

From a public interest, customer impact perspective, the proposed revisions of the existing OATT seem to be a positive push by the NBSO towards ensuring that unwarranted wording complexities are being avoided.

Indirect rate schedule changes and ancillary cap changes that result in rate increases could have significant financial effects on the electricity customer in the province. We have been told that this is currently not the case but are concerned about these changes forcing additional upward pressure on rates in the near future. The rate schedule changes must benefit transmission customers in New Brunswick and must meet the test of just and reasonableness out in the Public Utilities Act. This includes not only New Brunswick customers but all customers of the NBSO controlled area.

Our interest today is to ensure that customers' interests are served and our suggestions and recommendations to you are from that perspective.

In conclusion, the governing principle for the Board in this proceeding is set out in Section 58 of the Public

Utilities Act, which states that "All tariffs shall be just and reasonable". The municipal utilities fully support that ideal and are concerned about any impact that changes to the OATT may have on our customers.

We support changes to the OATT terms and conditions and the changes to the OATT rate schedules that do not have a negative financial impact on electricity customers in New Brunswick.

If the ancillary cap proposal increases cost to NB Disco, and in turn to its standard offer customers, then we cannot support the ancillary cap methodology until we know all the direct and indirect effects on our customers. If the change to the schedules will subsidize self-generators at the expense of other network customers, then we cannot fully support the self-generator rate proposal.

The Municipal Utilities believe that to allow the OATT revisions as requested by the NBSO, the changes must be in the bets interest of New Brunswickers, the electricity market in New Brunswick and lead to fair and reasonable rates to customers.

This is the end of our summation, Mr. Chairman.

CHAIRMAN: Thank you, Mr. Young. I am going to take a 15 minute break now and when we come back we will call on the Agent of the Attorney General and then back to you, Mr.

Whelly, for any remarks in rebuttal.

(Recess)

CHAIRMAN: Ms. Newman, I thought about you. Ms. Newman I owe you an apology. I forgot about you there. Do you have any comments you wish to make to the Board?

MS. NEWMAN: No, I don't. Thank you, Mr. Chair.

CHAIRMAN: Thank you. Mr. Hyslop? You haven't moved up front. Oh, yes, you have. Good.

MR. HYSLOP: Well, we weren't sure whether Ms. Newman would have comments so --

CHAIRMAN: I see.

MR. HYSLOP: Thank you, Mr. Chairman and Members of the Board. I want to I guess briefly begin by thanking a few people.

I did come into the process late. And to further complicate it, because of accepting the appointment from the Attorney General, it was necessary I divorce my former law firm. And I was in the process of resetting up a place to be found. And I would like to take this opportunity to thank the Board Secretary, Mrs. Legere, Marg Tracy for their assistance in getting me the evidence and the interrogatories as quickly as possible. It made my job a lot easier. And I would also like to thank my colleague, Mr. Whelly, Mr. Porter and Mr. Marshall. After

I had been able to retain the services of Mr. Thorne and get a handle on --

CHAIRMAN: Well, I just realized Mr. Whelly is among the missing. And I think it might be appropriate -- yes, would you, Peter. Thanks.

MR. HYSLOP: I can wait.

CHAIRMAN: Just hang on a sec' while we find him.

MR. MARSHALL: Excuse, Mr. Chairman. 15 minutes was right on this time. We apologize we were a little late.

CHAIRMAN: Go ahead, Mr. Hyslop.

MR. HYSLOP: Thank you, Mr. Chairman. As indicated, I would like to thank Mr. Whelly and Mr. Porter and Mr. Marshall. They took time out of busy schedules to meet with me to address some of the issues which made our interrogatory process, even at the late time that the Board permitted, I guess easier to proceed with.

With that in mind, I also respect the process that has gone on before involving meetings with the stakeholders and many of these issues, while unfamiliar to me, were very familiar to many of the other parties that intervened at these hearings.

And with that in mind where they have spoken for themselves, I shall refrain from doing so unless it's something that clearly would impact on a greater public interest.

With that in mind I believe -- and this is out of response to a question the Board put to Mr. Whelly relating to perhaps a degree of discretion they may have in making an order, I do draw the Board's attention to Section 111(4), which reads, "The Board shall, when considering an application by the System Operator in respect of an approval of a tariff pertaining to transmission services, base its order or decision respecting the tariff and all projected revenue requirements of the System Operator and the transmitters for transmission services and the allocation of such revenue requirements between the System Operator and the transmitters."

It's my view the Board should probably reflect on this and allow itself a fair amount of discretion in what it may do with the tariff and the type of limitations it may set on the tariff itself.

I say this only because I believe it is appropriate that we do not allow ourselves to get into a cycle whereby there is an infinite period of time before the System Operator is back before this Board.

And in this regard, I was very pleased to see the response of the System Operator to the Public Intervenor

IR-4, which reads in part, "Is the System Operator prepared to have its cost of services and rates publically reviewed periodically, for example, on an every three year's basis?" And the response was one word. "Yes". I think that that was certainly a positive response from the System Operator. And I hope it's something reflected on the family of companies of NB Energy.

With respect to the CPI, we are also cognizant, Mr. Chairman, that these rate applications cost money. And even more important, it involves the time, energy and resources of a great number of people associated with the New Brunswick System Operator and the other companies, which resources -- with no disrespect intended to the Board or anyone else -- might well be better spent in running the businesses properly. And we suggest that there has to be an adequate trade-off between the need for review and the need to have -- have the businesses being run.

We are also satisfied on the evidence that much of the costs of running the System Operator, Mr. Marshall's evidence was 96 percent -- are costs that are going to escalate in value.

So with some degree of reluctance, we would like -- we are in support of NBSO's application. But we would suggest that they get half of the CPI rate to cover a three year period.

And if we might look at the wording that is being requested in the changes to the tariff, which can be referred to in exhibit A-1 under the tab, Schedules 1 to 9 at page 91.

CHAIRMAN: Give that again?

MR. HYSLOP: I will give that again, Mr. Chairman. It's exhibit A-1. It's under the tab, Schedules 1 to 9. And it's at page 91. And this deals with the wording -- changes to the wording, the underlined portion of the changes to the tariff.

What the System Operator has asked for is on April 1st 2006 and on each April 1 thereafter, rates in the Schedule 1 will be escalated by 50 percent of the annual increase, if any, in the All Items Canada Consumer Price Index.

We suggest that there is certainly the authority within the direction provided in Section 111(4) of the Electricity Act, to permit the Board perhaps to allow wording as follows: "On April 1st 2006 and on April 1st 2007, rates in Schedule 1 will be escalated by 50 percent of the annual increase, if any, in the All Items Canadian Consumer Price Index."

This wording we would submit, Mr. Chairman, would have the effect of not allowing an automatic increase on April 1st 2008. And if such was required would result in a further application for a tariff modification and rate modification by the System Operator.

CHAIRMAN: Now, I am the internal optimist, Mr. Hyslop.

MR. HYSLOP: Yes.

CHAIRMAN: What happens if the All Items Canada Consumer Price Index drops?

MR. HYSLOP: Well that -- if that were to drop -- and my feelings on that would be that that would probably present a problem for the New Brunswick System Operator, because imagine many of their wages are, of course, subject to union contract.

I would make this comment perhaps by dealing directly with my thoughts on the Consumer Price Index. And I would leave these comments to the Board's thought. I am reluctant to tie anything with Consumer Price Index. And the reason for that, costs may increase, but the costs of running your business doesn't necessarily have to. And what I mean by that, there are efficiencies in the way you can run your business. There is ways you can allocate your people. There is new machinery, new technologies, new methods of managing information coming along all the time. And although costs of some of these may go up, the costs of running the business can actually go down.

I had the opportunity -- I won't say the advantage, because it's pejorative, but I had the opportunity and experience to work for five years in the private sector for the McCain group of companies before going back to law school. And I had to present budgets. And at one of these meetings where I was presenting my budget, I indicated it was a lean and mean business -- or a lean and mean budget. And I was told by one of the principals of those companies that they didn't pay me to be lean and mean. They paid me to be leaner and meaner.

And if I might suggest, Mr. Chairman, and with all respect to the people, the System Operator and their budgets, being leaner and meaner is looking for sharper ways to run your business. It's not looking for ways of saying well these are the costs of running it. And I would encourage that.

I would suggest that in view of the question that was just put by the Chair, that if there is a decrease in the CPI, that at least rates should be considered to be decreased half of the CPI. And I think that would be a great incentive for the NBSO to look to be not lean and mean, but leaner and meaner.

The third point -- and I will make another point. Let us say there is an increase in the CPI. And I did some rough calculations. One of the nice things would be is that if there was no increase in the cost of running the business and these rate increases were retracted, based on a -- I did it on the basis of 4 percent and 2 percent, which is quite generous, but in excess of another half million dollars could be returned to the customers of the System Operator.

I wish briefly to speak to the issue of Code of Conduct. And again I don't think this is a bitterly contested point. There would seem to be some agreement or suggestion from Mr. Marshall's evidence that if in fact some of the parties thought it was necessary that there was something they could do. I agree with Mr. Whelly's comment in his closing summations that this really is an issue of perception. And I tend to concur in that point. But the perception is as follows. The System Operator is supposed to be independent. However, it does have management services agreements with its sister corporations. It has long-term relationships -- inter-relationships of people in the family of companies. And although legally we have created a different system, factually in the terms of operating this company, a lot of those long-term relationships and the way people think will continue.

And if I was an outsider looking in, my perception is I would like to have a Code of Conduct. And if Mr. Marshall was offering in his evidence, then certainly we are asking as the Public Interest Intervenor to have any perception that can be removed to be removed.

I wish briefly just to touch on the different other items that were raised in Appendix A of schedule -- of exhibit 2, which is the various points that are set out.

With respect to the first two, congestion management and the new connection to policy, we recognize that these are clean-up points. And we have no opinion before the Board.

We did in our cross-examination raise a number of concerns with respect to disadvantages to wheeling-type customers and making them market participants. We are satisfied at the end of the day, the distinction is very blurred. It is not a significant point. And there are additional issues of administration. And we would support the application of the System Operator on this point.

With respect to the issue under item 4, to initiate residual monthly cost recovery, this has been spoken to by a number of intervenors. And we would support the initiative as put forward by the System Operator.

With respect to the issue of limiting the quantity of ancillary self-supply, this does seem to continue to be a contentious issue. And the parties who have an interest have spoken to the Board. But we would like to add one -- at this time, one additional point.

And that is as presently described, and in the wording that is being sought by the System Operator, is that it would appear to us to leave an unnecessary amount of discretion to the System Operator. And I would refer the Board to exhibit A-2, Appendix A, page 13. Where the suggested changes and wording are presented.

And the revised wording adds the following phrases and subject to maximum limits established by the transmission provider or alternate comparable arrangements. We would suggest that in view of the positions that have been taken by the parties to leave an unfettered discretion as to what these maximum limits might be, it might be appropriate that some limit be put in. And I would suggest -- and there is no evidential basis for this suggestion, it's more of an instinctive response based on what is hoped to be achieved -- but perhaps after the words limits which will not in any event exceed 15 percent might be appropriate.

CHAIRMAN: Mr. Hyslop, what do you have to say for Disco's presentation to us on this point, that is, it's premature?

MR. HYSLOP: Well my answer to that is it may well be premature if you are Disco and you have long-term contracts, but I think it's inconsistent, Mr. Chairman, with the overall conceptual desire to want to create as much as possible a vibrant and open market. I also understand that part of doing this is not to do it so fast that it results in having complications that result in some of the problems that have happened in other jurisdictions in North America.

I think what I am suggesting is that perhaps this is a halfway point that lets the System Operator start to play with its theory but it shouldn't be so significant as to put the distribution company between too big of a rock and a hard place. With respect --

CHAIRMAN: I interpret that as being aggressively neutral.

MR. HYSLOP: That's stick-handling the best I can, Mr. Chairman.

CHAIRMAN: Thank you.

MR. DUMONT: Mr. Hyslop, could you repeat how you would phrase this in schedule 3, what you just mentioned?

MR. HYSLOP: Yes. I would add the words after the words subject to maximum limits, the wording we would suggest that would be added, which shall not exceed 15 percent, Mr. Dumont.

MR. DUMONT: 15?

MR. HYSLOP: 15.

MR. DUMONT: Thank you.

MR. HYSLOP: Thank you. And I will repeat, you know, on that point that maybe those that feel they are more affected may want to comment if they feel that some type of wording like that is appropriate but maybe disagree with me on the number. I don't know.

We support all of the other proposed wording changes going through and would comment briefly on the intra-hour behaviour. We do understand that this appears to have been an issue which was particularly important to Nova Scotia Power which they have not spoken in summation nor in cross-examination.

We were satisfied in particular with the fact that we were moving to market pricing as opposed to penalty pricing for such activities and the fact that the financial consequences are dealt with immediately makes sense. We are also I believe on the understanding that there is going to be a Nova Scotia open access transmission tariff which is likely to reflect similar thoughts as are being suggested in New Brunswick. And so we support the applicant on that point.

Mr. Chairman, those are the essential comments. The big point that we are pushing is not to allow the regulation of the electricity industry in New Brunswick to be left open ended into the future, to have the right balance between what it costs and the responsibility for the regulator to be involved balanced as fairly as possible.

Going back to the first point we made on the use of the CPI for escalation of rates, while that has some merit I think it also has -- it can't go on into infinity.

There was also a question raised -- and I thank Mr. Thorne, we discussed this -- the Board did raise an issue with respect to the issue of the second line. This was in argument and we would like to go on the record publicly as stating that if the second tie line is to proceed the impact of the service costs and the costs of running their business to Transco and the NBSO, we would support and encourage the prior public review of any such process by this Board.

Those are our comments, Mr. Chairman. I thank you and the other members for having me today and I also again would like to reiterate my thanks to those that assisted me in the short period of time I had to work with.

CHAIRMAN: Thank you, Mr. Hyslop. And if you recollect my indication to Mr. Whelly was that some time in the not too distant future why counsel and principals perhaps from the SO and Transco together with yourself and Board counsel, et cetera, should sit down and just talk about where we go from here vis-a-vis the legislation, et cetera.

Some of my Commissioners may have questions. No? Good. Thank you very much.

MR. HYSLOP: Thank you very much.

CHAIRMAN: Mr. Whelly, do you want five minutes?

MR. WHELLY: I think I took my five minutes just before Mr. Hyslop spoke. And I will proceed now. Thank you, Mr. Chair.

I will address just a few of the issues that have come up in the responses from the Intervenors.

First of all, I want to talk about this cap on self-supply. I am always nervous when I disagree with Mr. Morrison and I don't disagree with him on one point and that is that the SO doesn't have all the information it needs to make a decision right now. And that's one of the reasons why the SO is not here today asking for approval of a specific cap on self-supply. It is seeking approval for a process that can result in the establishment of a cap that the SO believes will assist in developing a market.

CHAIRMAN: Mr. Whelly, in that regard, and this is just me thinking as I hear the participants, what -- for instance if the Board were to rule that -- not to approve that change in the tariff today but in accordance with what Mr. Morrison has suggested wait until the actual what is available in the market is available, and then to invite a request at that time and the Board have a written proceeding, not an oral one at all, and for instance I have even been thinking that one need not advertise it but simply give the notice to the parties that were present here today. And then Mr. Morrison's concern in that regard would be answered and certainly I would not expect the SO to set the cap until he has in fact received that information anyway. And then the Board could depending on the participation that we received in the written hearing set the cap at that time and put it in the tariff.

Any comments on that? Do you want a minute to speak with the SO?

MR. WHELLY: Mr. Chair, in response to your question, part of the concern and I was going to mention is it's almost a chicken and egg question. And that what we are trying to do is make the market attractive enough to have suitors. And sometimes the suitors, we expect the suitors will want to know that there is a process to get -- to get a market there with sufficient demand that develops their interest to actually even respond to an RFP to say, yes, I am interested in becoming involved in this, because I know that the System Operator is going to make sure there is a market.

So the preference of the NBSO would be to have some room to move. The NBSO does not object to some limit on the extent of the cap. The Public Intervenor has suggested a 15 percent reduction is the maximum reduction that should be approved. And the NBSO could live with that.

We think -- we think that the wording is backwards. And that the wording Mr. Hyslop suggested should be 85 percent and not 15. But the concept is one that is not offensive to NBSO.

Let me say as a general statement that the SO recognizes its obligation as the independent operator. And is to operate in the interest of market. It has -- it has been given discretion in a number of areas. And the SO believes that this is an area in which it should have discretion. And I don't believe your question is inconsistent with what I am going to say next. And that is that this idea of a market cap also appears in the Market Rules, which don't supersede the tariff. And we can only take it now as a statement of a policy that is attractive to government.

So I guess what we would like to see is a strong signal that a cap is a possibility if there is capacity in the market for it and if the pricing is correct.

CHAIRMAN: Thanks, Mr. Whelly. This is turning into quite a hearing. First we had an elephant and a mouse. And now we have got a chicken and an egg. Go ahead, sir?

MR. MARSHALL: At least we don't have any butterflies.

MR. WHELLY: We heard the comments as well about the concern over doublepaying long-term contracts. There is clearly -- there is the possibility once you have any change that certain people may -- outside the norm, will be affected negatively.

The difficulty is then do you hold up all change because a very small minority may be affected or do you have another mechanism to look after that small minority. And we believe that there is a mechanism to deal with that small minority. We believe they have the ability to come back to the Board on individual cases if they feel that as a result of the application of a tariff that they are improperly affected, they can appeal to this Board.

At this stage, when we are talking about, for example, long-term contracts and the impact of a cap, it's speculation. And it's speculation because we don't know what the cap would be and we don't know when it would be implemented. We don't know what impact it would have on a specific contract, because those contracts aren't before us.

So these are items that can all be addressed as part of the fallout of a change in the tariff that can be looked at on a one-off basis to rectify the problems. And this Board has the discretion in our view to do that.

There was an issue raised on small customers and self-supply. The concept is that there is a certain amount you are allowed to self-supply yourself as an absolute quantity in megawatts, so that you are not obliged -- the cap doesn't apply to that first threshold amount. The cap only kicks in above that threshold amount. So small customers in fact wouldn't be affected by the cap.

MR. SOLLOWS: Excuse me. Did I understand from your previous point that you anticipate that we will be reviewing the power purchase agreements between Disco and Genco, the contractual arrangements for ancillary services?

MR. WHELLY: No. What I intended to refer to was circumstances that might exist. And this was raised by the municipalities. That there could be long-term supply contracts and people who, as a result of the imposition of a cap, may be forced to pay twice.

So in circumstances like that, we believe that the people who are burdened by those contracts have the ability to apply to this Board to say there is an injustice being worked upon me under this tariff and I want an exception in the tariff. And you could then impose an exception on the tariff that may say, all right, this self-supply limit doesn't apply to you until the expiration of this particular contract.

CHAIRMAN: That concern could also be covered, could it not, Mr. Whelly, by simply putting in that provision of the tariff, subject to any long-term contracts outstanding as of the date of the effect of amendment to the tariff?

MR. WHELLY: That could handle it as well. Except for Disco's long-term contracts.

CHAIRMAN: Disco is represented here.

MR. WHELLY: Ably. There could be an impact on Disco. And the SO recognizes that, for example, Disco may have stranded costs. But it has -- it's a regulated entity as well. It has the ability to come back before this Board and deal with that issue.

And what -- obviously what we are headed here is this proposal isn't here to penalize people. The only reason it's here is that at the end of the day, the SO believes that there is an opportunity to get lower costs for ancillary services. And ideally what will happen is those with -- even with long-term contracts will actually find themselves better off, because they will be able to go to the market and buy services at a better price.

Mr. Belcher, in his comments, referred to a number of items that caused my clients some concern. I am not going to address all of them. But, for example, there was reference to double payments, payments being made to Genco and payments being made to the SO. Payments made to Genco are outside the tariff. And if the Northern Maine Independent Operator has reached agreements that force them to make payments to Genco that they think are unfair, we can't -- we can't help that. They should be talking to Genco about that, about how their rates are structured.

There was a concern that the -- that there was a difference between the manner in which RMC charges were collected and the way they were distributed. If the Northern Maine Independent System Operator believes that it's not being fairly treated, it has an option. It can buy it's power at the bus bar of the generator in New Brunswick, become a transmission customer in New Brunswick. And by doing that it ends up sharing in the distribution of the -- of whatever proceeds may be distributed under RMC.

And I think the only other item I wanted to mention had to do with Mr. Hyslop's reference to the 15 percent. And as I have mentioned earlier, I think it should have been 85 percent and the amendments to which he referred.

That's all I have.

CHAIRMAN: Good. Thank you very much, Mr. Whelly.

MR. WHELLY: Thank you.

CHAIRMAN: The Board will, of course, reserve decision. And again I want to thank all of the participants. It's a great pleasure to chair a meeting when people are all cooperating as you have over the last number of days. Thank you.

(Adjourned)

Certified to be a true transcript of

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Reporter