MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO
ELECTRIC COST OF SERVICE
REVIEW TECHNICAL CONFERENCE

Before Board Panel:

Graham Lane	- Board Chairman
Bob Mayer	- Vice Chairman
Kathi Avery-Kinew	- Board Member
Len Evans	- Board Member

HELD AT:

Public Utilities Board
400, 330 Portage Avenue
Winnipeg, Manitoba
November 24th, 2005

Pages 1 to

APPEARANCES

Bob Peters	)Board Counsel
Patti Ramage	)Manitoba Hydro
Byron Williams	)CAC/MSOS
Tamara McCaffrey (np)	)MIPUG
John Osler	
Patrick Bowman	
Susan Robinson	
Doug Buhr	)City Of Winnipeg
Randall McQuaker	)TREE/RCM
Peter Miller	
Michael Anderson	)MKO

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--- Upon resuming at 1:00 p.m.

THE CHAIRPERSON: Thank you for returning or coming this afternoon for the technical conference related to the review of Manitoba Hydro's cost of service study.

While this is being hosted at the Board's offices and hearing room, it will be Manitoba Hydro who will be making the presentation to all of us. The Utility sought an opportunity to provide a briefing as to information related to its cost of service study methodology, including the changes it proposes to its methodology.

It is our hope and intention by having a technical conference all parties will gain a better understanding of the information that Manitoba Hydro is presenting in their COSS Application filing.

Before I turn it over to Mr. Peters and others for their opening comments I will indicate again that my panel members are: Len Evans, Dr. Avery-Kinew and Board member Vice Chairman Mayer.

Mr. Peters, could you provide us with any opening comments you have at this time and bring us up-to-date in the discussions over the lunch hour?

MR. BOB PETERS: Yes, thank you, Mr.

Chairman. Good afternoon ladies and gentlemen, Board Members.

I indicated to those who were at the pre-hearing conference earlier today that the technical conferences are relatively novel in Manitoba and I know a number of others in the room were present when Manitoba Hydro last conducted one for one (1) of its applications.

But with that in mind, Manitoba Hydro wants to present information this afternoon about its cost of service methodology and the changes it is proposing.

All parties are welcome to ask questions of Manitoba Hydro and -- and trust me no -- no question should be considered silly or inappropriate. If it's a legitimate question you have you can probably be sure that there's others in this room that have it.

And we recognize that there may not be -- microphones may not be spread around too readily, but when you do have a question maybe just stop whoever's presenting and then work your way quickly to a microphone and I think that'll help us all.

I did indicate this morning that the evidence of Manitoba Hydro's representatives will be sworn and under oath for the purposes of being part of the record. In that way, if the Board is hearing this information it could be considered evidence in the proceedings.

And as certainly all the lawyers present will understand and -- including Mr. Williams the -- the evidence, not the rantings and ravings of various parties in the newspapers will -- will go to form the basis of any decision of the Board.

And that's what the Board relies on is the evidence that it hears in these proceedings. It will also be a transcript that if parties who -- who have different views or different issues from Manitoba Hydro, they'll have a record of what Manitoba Hydro has said and they'll be given an opportunity through this process to provide their own views.

Mr. Chairman, this morning I asked if there were any objections to the Board Members being present at the technical conference, provided the -- the Witnesses were -- were sworn and their testimony formed part of the proceedings.

There was a legitimate concern raised and we had an opportunity over the lunch hour to review Manitoba Hydro's slides and discussed this being a tutorial as opposed to a -- in my words a sales pitch and -- and parties were all in agreement that tutorials are nothing but a good thing and encourage them.

So I believe the materials that have now been presented are satisfactory to all. Parties are aware that Manitoba Hydro will discuss the prospective Cost of Service Study 2006 that they have prepared. I believe we've reached a resolution on all concerns raised and that there are no longer any objections to the Board being present. If there are any such concerns I hope that people will voice them when they're given an opportunity, shortly, to -- to provide them to the Board's attention.

Mr. Chairman, I suggest that after my comments you turn to all of the parties present in the hearing room for their introductions and remind them that when they ask questions it would be helpful for our reporting service if they could state their name at the outset and then pose their questions so that we can have an orderly transcript from the technical conference.

Also, in any of those opening comments by the parties present, if there are any continuing objections to the Board being present under the conditions that we have outlined, I would ask them to make that known at this time.

Those are my comments, Mr. Chairman, Thank you.

THE CHAIRPERSON: Thank you, Mr. Peters.

We'll go quickly around the room, once again, to find out which of the parties are in attendance and if they have any opening comments that they may want to make this afternoon.

Ms. Ramage...?

MS. PATTI RAMAGE: Thank you, Mr. Chairman, we have no opening comments. I would indicate that Mr. Warden and Mr. Wiens are sitting with me. Mr. Thomas will making the presentation and we have added to this morning's panel Mr. Harold Surminski who I believe is a familiar face to this Board.

Mr. Surminski has -- has come down this afternoon in case there are any questions with respect to the areas falling under his responsibility.

THE CHAIRPERSON: Thank you, Ms. Ramage. For the CAC/MSOS, Mr. Williams, do you have any opening remarks at this point?

MR. BYRON WILLIAMS: Just an introduction. To my right is Mr. Bill Harper sometimes known as Mr. Bill Turner, but he prefers Harper, he advises me, and we're ready to listen with interest. I'm not sure if Ms. Desorcy's here; she is returning because she's looking forward to the tutorial as well.

THE CHAIRPERSON: Thank you, sir.

For MIPUG, Mr. Bowman, Mr. Osler...?

MR. PATRICK BOWMAN: Yes, hello. It's Patrick Bowman. Ms. McCaffrey wasn't able to be here this afternoon and Mr. Osler has also stepped out, so I will be here for this afternoon and we had no other comments.

THE CHAIRPERSON: Thank you, sir.

Mr. Buhr, are you still here?

MR. DOUG BUHR: I am, sir, here for the City of Winnipeg and we have no comments.

THE CHAIRPERSON: Thank you, sir. I don't believe Mr. Anderson is back. He'd indicated he had other pressing matters.

Is Professor Miller still in attendance? There you are, sir.

DR. PETER MILLER: Yes, I am, thank you and I'm pleased that is going forward, otherwise no further comments.

THE CHAIRPERSON: Thank you, Professor. So again, thank you everyone. First of all I should ask, is there any other party that wishes to identify themselves as being present or in the expectation of wanting to say something at some point?

Okay. If not, then thank you everyone for attending and providing us with the comments that we've just received and those that will follow.

I now want to turn it over to Manitoba Hydro. The Board will sit back and observe. I'm inviting all those present to ask as many questions as they may have or wish.

The purpose of this technical conference is so that we can all gain a better understanding of the material that will come before the Board in this process. As was the case with the pre-hearing conference, transcripts of this conference will be available and posted on our website.

Mr. Singh...?

Oh, there you are, sir. Please or swear or affirm Manitoba Hydro's witnesses?

MANITOBA HYDRO PANEL:

MR. VINCE WARDEN, Sworn

MR. HAROLD SURMINSKI, Sworn

MR. ROBIN WIENS, Sworn

MR. CHIC THOMAS, Sworn

THE CHAIRPERSON: Thank you, Mr. Singh.

Ms. Ramage, please take it away.

MS. PATTI RAMAGE: I will simply turn it over to Mr. Thomas.

PRESENTATION BY MANITOBA HYDRO:

MR. CHIC THOMAS: Good afternoon, everybody. Board Members, I'm glad you could attend.

Just a few housekeeping matters before we get going. Number 1, Ms. Ramage alluded to, we've got Mr. Warden and Mr. Wiens and Mr. Surminski to help me out along the way for either the questions I can't answer or where I get the Corporation into trouble.

Also helping me is Brenda Wallace because I don't trust myself to push -- push the buttons and of course the remote doesn't work.

One (1) thing that I would like to remind everybody and for those people that -- that do have the cost of survey -- cost of service on their night table there's a little bit of confusion and I'd just like to clarify the terminology before we go forward.

In the materials that were filed previously we had a current version and a recommended version. In this presentation when I refer to the, "current version," that's now the previous version and the recommended version is now the current version.

MR. BOB PETERS: Just to interrupt so I can make sure -- it's Bob Peters interrupting -- what you're telling the Board is in the materials you've handed out today the current methodology is the current methodology that Manitoba Hydro is supportive of, but this Board hasn't yet ruled on that?

MR. CHIC THOMAS: Correct.

MR. BOB PETERS: Okay.

(BRIEF PAUSE)

MS. PATTI RAMAGE: How do you feel, Mr. Thomas?

MR. BOB PETERS: Do you care for a -- do you care for a drink?

MR. CHIC THOMAS: Yeah. Looking good, feeling fine.

Okay. I think I got the housekeeping matters out of the way, so I guess we'll get right into it. Oh, one (1) other matter.

If you have been flipping through the pages, pages 27 through 29 and 30, 31, 32 and 35 are no longer there. So we can count, unfortunately we just had to pull those pages at the last moment.

So if you're looking for those pages, they're not supposed to be in there.

MR. BOB PETERS: Blame it on Byron.

MR. CHIC THOMAS: Blame it on Byron. Okay. Without further ado I will get into this. Thank you.

So -- so some of the things we're going to talk about and I'll -- so the first thing is we're going to go through some of the basics.

So, for example, what is a cost of service study, whether we're talking Manitoba Hydro's cost of service study or anybody else that does a cost study. And we're going to get into some of the considerations when you're doing an electrical cost of service.

We're going to talk about Manitoba Hydro's previous and current method with the caveat I've explained earlier. And then the differences and the treatments of specific items in each method.

Some other methods that we had considered and were directed by the Board. And the key issue, export revenues, that was pages 27 through 29 that are no longer in the presentation so that's -- that's not applicable anymore.

So starting right from the basics, whether it's an electrical cost of service study or any other cost of service study, all it is is a method of allocating a utility's cost to its -- to its customer classes.

And it's used to determine that rates charged to the different customer classes are fair and equitable; because it's not an exact science, so we have to make our best judgement when going forward that -- that what we're doing and how we're assigning those costs to customers is the most fair and rational way of doing so.

So, as -- as we've heard in different proceedings there's many different ways you can do a cost of service study, and that's the focus of this technical conference right now, is to discuss just two (2) methods that Manitoba Hydro has done and is now proposing.

So some of the key considerations that we have -- I think we're out of -- no, sorry, so still with the basics now.

Any cost of service study has three (3) main steps. And that's the functionalising, where we separate the -- the assets of the corporation that allows it to deliver its product to its customer. So in Manitoba Hydro's case we have the generating stations in the north and the transmission system that brings it down, and so on and so forth. And I'll get into the functions a little bit later.

And then we classify those costs into the three (3) components of energy, demand and then customer cost. And then finally, when we have all those things accumulated, we do a -- we do what we call the allocation process that gets those costs directly to the customer classes.

So, some of the key considerations for Manitoba Hydro are generation and transmission functions represent approximately 75 percent of total cost. So it's the treatment of these two (2) items that can significantly affect the results that we get.

There's numerous techniques, as I've explained, that you classify generation and transmission functions, but the method chosen should reflect both the utility system -- system and -- and of course the customer load characteristics. And of course, as we've all heard now and in previous hearings, the treatment of export revenues has a major impact on the results.

So, specifically in terms of Manitoba Hydro, what we do is an embedded cost study based on historically incurred costs. So our oldest plant is in the books for the price it was built for at that time, whereas the newer plant will reflect newer cost. It's usually done on a perspective basis to support rate applications.

And going back to those five (5) functions that I alluded to earlier, the five (5) functions that we use at Manitoba Hydro are generation, transmission -- are anything above 66 kV, the sub-transmission system which is between 33 and 66 kV, and then the distribution system and then customer service. Oh, you're one step ahead of me are you? Did I miss one? No, I did. My apologies.

So some of them -- some of the things -- some of the classification methods that you can consider when constructing your cost of service study are things like the type of generation asset that you have installed: Thermo, nuclear, hydraulic.

Well from Manitoba Hydro's case, we're predominantly a hydraulic utility. The planning and operating constraints and/or policies of the Corporation and/or of the utility.

And then the pattern -- the pattern of system loads throughout the year and which of the seasons the system peaks. For Manitoba Hydro that's typically in the middle of winter, first thing in the morning or early in the evening on the coldest day of the year.

Another thing that we use in our previous method was something called the System Load Factor. And then other considerations are things like purchases and sales to non domestic utilities.

Now we've already gone through this one and again, I'll just reiterate the five (5) functions. Again, it's generation, transmission, sub-transmission, distribution and of course customer service.

Now everybody's going to love this next slide and most people won't be able to see it but what this does is it -- it's an attempt to schematically graphic the steps that we do.

So you can see on the far left hand side we've got our -- our annual costs that we -- that we end up functionalising and those are our operating expenses. And then we've got finance expense, which included in that is capital tax and our forecast net income and depreciation expense.

So then the next step, moving to the right is we -- we put those costs into the five (5) functions. And -- and you can see that we've put the costs in there for -- for your reference that you can't read. Hopefully you can read it on the handouts that you have.

But you can see that across the way those costs remain constant. It's just how we're separating those costs. So we're at the functionalization stage. And then what we have to do is classify it into our energy, allocators, our demand allocators and then of course our customer related costs.

And again, you can see the bulk of the costs are in the energy and demand related costs.

MR. ROBERT MAYER: Those figures, are they in thousands of dollars?

MR. CHIC THOMAS: Yes, they are. Thank you, Mr. Mayer. And I should also point -- point out that this is for Manitoba Hydro's current version as well.

MR. BOB PETERS: Chic, it's Bob Peters over here. If I could just slow you down on the -- on -- on slide number 6, I don't know if Brenda can find that one. You talked about different considerations when deciding on how generation and transmission should be classified.

You gave -- you listed five (5) different considerations, can you just explain or maybe Mr. Warden or Mr. Wiens or Surminski, about some -- apply those -- those points to Manitoba Hydro's system?

I mean, for example, what difference does it make if it's hydraulic or not, in terms of how you're going to classify the generation assets? Can you maybe explain it to that level?

MR. ROBIN WIENS: Robin Wiens here. I'll try to respond to that.

Going down the list of these considerations, and some of you may recognize these considerations actually. Some time back, I believe in April of 2004, Manitoba Hydro filed a report that was prepared by NERA regarding the classification and allocation of generation and transmission costs.

And these types of considerations appeared in that study. And when you're looking at the type of generation assets installed, system planners and then going on to build the system, we'll try to put different types of assets into service to meet the requirements of customers, depending on a number of factors.

And of course, on the cost that's involved in putting those assets in place. Some are cheap to put in place and expensive to run, others are very expensive to put in place and not so expensive to run.

It will depend on the nature of the load that's being served, if the load is, for example, has a high load factor, you would tend to look at a combination of plants that is capable of being run, optimized at the lowest cost over the entire period of the year.

So you will have in place these various types of resources --

THE COURT REPORTER: Excuse me, Mr. Wiens, could we take a short break, I seem to have stalled. Five (5) minutes?

MR. ROBIN WIENS: Yes.

(BRIEF PAUSE)

MR. CHIC THOMAS: I think when we left off Mr. Wiens was just getting warmed up, so I'll leave it back to him.

MR. ROBIN WIENS: Yeah, I was talking about why you would invest in different types of generation assets, and the different types were put in to meet different requirements of the system.

Typically you would look at, in a typical hydro-thermal system, where hydro was only part, not like -- so much like Manitoba Hydro where Hydro is virtually the entire system, and that -- and that's because of course of the nature of the resource that's available to us, and -- and the economies which we can exercise in putting in place.

But very generally utilities will put in more costly resources, in order to have its resources with a higher capital cost -- a higher installation cost, in order to take advantage of lower operating costs, or lower variable costs if the resources intended to run a lot of hours in the year or to meet the base load portion of the load.

And the -- they will put in less costly resources for typically less costly to install, but usually more costly to run, for example, combustion turbines, in order to meet loads that only have to be met for a small part of the year.

So clearly if you are working with a resource that is working most of the year, it is meeting a big chunk of the energy needs of the utility, and relatively speaking, contributing less capacity.

So if you're working with -- if you're working with resources that are intended to provide service over the entire year, they will tend to be related more to energy than to capacity.

If you're dealing with resources like a -- a backup diesel facility that normally is only going to run when something else fails, or when there are unexpected increases to the load, that is more likely to be seen as a capacity resource.

Planning and operating constraints or policies, that will have an affect on the -- on the times at which the system is constrained and may dictate to you what -- that times you choose to designate as peak times.

Similar for the -- for the third point, the pattern of system loads throughout the year, and in which season the system peaks. If you have a very pronounced and distinguished peak at one (1) point in the season, you may look to a different classification method or allocation method than you would look at if the load were fairly constant over the whole year, or if there were peaks in most months of the year.

System load factor is one (1) way of looking at the entire system. And -- and if you want us to sum up how the resource is being operated over the course of the year in one (1) number, the system load factor is a pretty good number to do that with.

And as you'll see, when you're dealing with a system like Manitoba Hydro's, which was predominantly hydraulic, and in which most of the units had the capability to deliver a lot of energy, in the past we had used the system load factor as a basis for classifying that resource.

Purchases and sales to non-domestic entities, clearly they will have some affect on what happens in terms of categorizing your generation resources. We have a hydraulic system in Manitoba, and probably on a relative basis we have probably the highest export of electric commodity of probably any utility in North America, I -- I could be wrong on that, but if it's not the highest, it's pretty close to the highest.

And so that has a bearing on the choices that we make when carrying out a Cost of Service Study. And -- and as we'll see as we move further into this process, that it's one (1) of the factors that we have to consider in some detail.

THE CHAIRPERSON: And much shorter, but my last question for hopefully a while, Mr. Wiens, could you just define system load factor and tell us what -- what it is related to Manitoba's domestic load?

MR. ROBIN WIENS: A system load factor is very simply taken, it is the average use of a system throughout the year, divided by the peak use of the system.

So if you take -- if you take the energy component, the kilowatt hours or the gigawatt hours and you divide them by the number of hours in a year, that will give you the average energy. And then the peak of the system will give you the peak and you divide one (1) into the other.

Manitoba Hydro's domestic customer classes historically have run between 57/58 percent of system load factor, up getting towards seventy (70), and the trend, over time, has been that the system load factor has been increasing.

In this particular study the domestic customer classes had a system load factor, I believe it was 66 percent.

If you were to include all of Manitoba Hydro's sales, the load factor would be considerably higher than that.

MR. CHIC THOMAS: Thank you, Mr. Wiens. I think we're at the very confusing diagram here. So as I was saying --

MR. BRENT MCLEAN: Excuse me. Can I ask a question on this page?

MR. CHIC THOMAS: Sure.

MR. BRENT MCLEAN: On this -- on this chart you've got total expenses of a million or a billion five (5), and then you've functionalised the total expenses of a billion five (5) and then you've classified them. The total expenses includes net income, the net income includes the net export revenue.

In the material that you've filed, if -- if I'm reading it correctly, the functionalization and classification numbers are actually net of -- of net export revenue?

MR. ROBIN WIENS: That's correct.

MR. BRENT MCLEAN: It's -- it's something like a million one. I wonder if you could just explain the reason for that?

MR. ROBIN WIENS: So, first of all, well, if we're talking about the -- the current method, what we do is, yeah, we look at the -- we look at the total costs and then right now in the -- in the current method what we do is we've created an export sub-class with a firm and an opportunity.

But what we do is, yes, we only want to allocate those costs to the domestic customer classes, so we exclude export from that.

Yes, you're right that net income would include net export revenue. But the costs of net exports have been excluded. Does that answer your question, Brent?

MR. BRENT McLEAN: Yes.

MR. BYRON WILLIAMS: I'd like to just ask a question on this same thirty-two (32) arrowed schematic which I -- going to the figure of -- oh, it's Byron Williams. Ms. Ramage wants to know who I am.

If I look at the total cost associated with functionalisation being about $1.5 billion at the bottom of the functionalisation column; do you see that?

MR. ROBIN WIENS: I do.

MR. BYRON WILLIAMS: And my understanding is that that's under the current method. If I was looking for the total cost under the previous method or under the NERA method, that would be a different figure; is that right?

MR. ROBIN WIENS: That's correct.

MR. BYRON WILLIAMS: And could you help

me to understand, or my colleagues to my left and right to understand, why that is a different method -- a different number?

MR. ROBIN WIENS: Sure. Maybe I'll take a step back and start with the previous method. And you may or may not recall, in the previous method we didn't have an export class, we just had a gross export revenue figure which we deducted variable water, fuel and power costs from that number.

In the case of the '06 study that number was about 107 million. So from the total annual costs we would deduct -- or specifically from generation we would deduct that $107 million. So -- so in the -- in the previous methodology your total cost will be a little less.

Now, when we move up to the NERA method we do create an export class. And -- and in that case our export sales are allocated generation and transmission costs in the same manner as any other domestic class.

So, in that case we don't have that 107 million that I cited that comes off the generation and transmission costs. So that number has to get added back in to generation so everybody gets allocated their piece of that cost.

And then moving on now to the current

method, we've -- we've further segregated the export class into a -- a firm export sales and an opportunity export sales.

Now, to confuse it even more now, on the firm sales like -- like the NERA method we're allocating cost to that class in the same way as any other domestic class. But on the opportunity sales what we're doing is what we did in the previous method or assign them a portion of the water, rentals, fuel, and power costs.

Now, because we're segregating out that export class, that number will be something less. In fact, it's about $48 million versus the $107 million. So that's why in all three (3) versions you'll see a different bottom-line number.

MR. BYRON WILLIAMS: Thank you.

THE CHAIRPERSON: Mr. Miller...?

DR. PETER MILLER: You -- you've probably answered this but the cost in the -- the first three (3) columns there, the billion five (5), are those net of export credits or prior to export credits?

MR. ROBIN WIENS: When you say "export credits" you mean the cost of exports or the credits --

DR. PETER MILLER: Well, this just shows the domestic situation but we all know that there is this export situation.

MR. ROBIN WIENS: Yes.

DR. PETER MILLER: And my question is -- and we know that the -- the various methodologies allocate net revenue back against various costs.

MR. ROBIN WIENS: Yes.

DR. PETER MILLER: And I'm just wondering, when you're diagramming this are you including the -- the operating, finance, and depreciation after the export revenue has been credited or before it has been credited?

MR. ROBIN WIENS: After.

DR. PETER MILLER: After. Okay. Thanks.

MR. CHIC THOMAS: Any other questions with this one before we move forward? Going once.

Now specifically we'll get into Manitoba Hydro now. In the -- in the '05/'06 GRA Order Number 10104 the PUB directed Manitoba Hydro to prepare four (4) different versions or methods of the '06 study.

We filed those ones on February 1st. And what they are is, the previous methodology or the one that has been approved by the Board. There is the so-called NERA methodology that we just spoke briefly about.

The one championed by TREE RCM, the generation vintaging method where low cost resources go to domestic customers and residual domestic consumption and the export class gets allocated the higher cost resource. And then of course Manitoba Hydro's current approach.

The first allocation, in all cases, the first allocation of net export revenue is used to offset the revenue loss associated with uniform rates. And in any version that we show or any of the results we show, this uniform rates adjustment will be present.

DR. PETER MILLAR: Just to clarify that, uniform rate adjustment includes the diesel customer class; is that correct?

MR. CHIC THOMAS: Yes. And as a good segue on uniform rates, this busy looking slide with a whole bunch of numbers is again how we -- how we calculate it.

Now without going through the numbers in detail, basically what we did is, for 2002 was our first full year post implementation of uniform rates. So for all the customer classes affected and those would be all the ones with any zonal distinction: Residential, general service small, general service medium and street lighting. What we did is we looked at the revenue reduction and then divided it by what their revenue was, prior.

And that's -- and you can see the

percentages on the far left hand side represent what that revenue reduction was on a sub class by sub class basis.

So going forward, and in the case of 2006 what we did is we took those percentages that you see and multiply it by our 2006 forecast revenue. And if you go through the iterations, you could see that we've allocated that revenue back to the appropriate sub-classes. And looking at the bottom figure, you could see a number of $16.7 million which, again, was taken from that export revenues.

And I'll get into net export revenues in just a little bit but -- but again, that one will come off the top of export revenues. Now --

MR. ROBERT MAYER: Excuse me --

MR. CHIC THOMAS: I'm sorry.

MR. ROBERT MAYER: Is it your intention to apply the same methodology for '06/'07? And into the future or has that been thought through yet?

MR. CHIC THOMAS: We have discussed that internally and because of -- and Ms. Ramage alluded to it earlier with MIPUG's pre-asked questions about zonal distinctions eroding over time with the uniform rates legislation.

Our intent going forward is to just have a single number for each class. For example, I believe for the residential class it represents about a 3.5 percent reduction. So for example, in our '09/'010 study we'll just add back 3.5 percent to total residential revenue.

Any other questions?

MR. BILL HARPER: Bill Harper with Byron. I was trying to backup on that. I think the question Mr. Peters asked about, diesel rates --

MR. CHIC THOMAS: Yes.

MR. BILL HARPER: And my understanding was that the original application of uniform rates didn't include the diesel communities, it was just the grid connected communities that the diesel -- that the uniform rate policy was applied to?

And -- and also the other thing was I didn't see diesel communities on the chart that you had there either. So I'm just asking you to sort of reconfirm that the diesel communities were actually part of this as well.

MR. ROBIN WIENS: I -- I'll clarify that response as far as the inclusion of the diesel facilities and then I'll ask Chic to respond to the second part of your question.

The diesel communities were not included in the uniform rate legislation except much of the consumption in those communities is affected by it because they all pay basic charges and they all, other than government customers, they all have two thousand (2000) kilowatt hours of energy at grid rates.

So, in fact for most of the usage in the diesel communities, indirectly, they are covered by the -- by the uniform rate legislation; that was all. I hope -- I hope that was responsive. I -- I just feel strange when my back is to the person who is asking the question.

MR. CHIC THOMAS: Sorry Bill, what was the second part of your question?

MR. BILL HARPER: Actually you just sort of triggered, the second half was just that, you know, diesel wasn't outlined on the -- on the chart here, but I assume if they were buried in the -- in the specific customer class going down there, that's maybe the answer.

MR. CHIC THOMAS: Well as Mr. Wiens alluded to, like, yeah, diesel is a separate study all together, and is not included in our costs here. But so -- but in terms of the uniform rates it is uniform rates automatically transfer over to our diesel communities, for those -- for those first two thousand (2000) kilowatt hours, at of course the basic charge.

MR. BILL HARPER: So there'd be a little bit more money than the $16.7 million -- sorry, there'd be -- you know, 16.7 is associated with the grid -- with the grid connected customers then and there'd be a little bit more money on top of that going -- going for the uniform rate issue associated with the diesel communities then?

MR. CHIC THOMAS: Yes.

(BRIEF PAUSE)

MS. PATTI RAMAGE: I think rather we best not rely on our memories on that one (1), and we will go back and check.

MR. CHIC THOMAS: Okay, so -- so now we'll -- so what I'd like to do now is we'll start from the previous methodology, show you a little bit about the classification and allocation on that part of it and then we'll move over to our current methodology.

So we had just talked about the system load factor, and you can see that we use the system load factor to classify our generation costs. So to give you an example of exactly how we do that in our study, I just use a -- an arbitrary number to make it simple, of a thousand dollars ($1,000) of total generation and transmission costs.

And again, looking up above you can see what Mr. Wiens had mentioned earlier, that we have a 66 percent energy and a 35 -- 34 percent demand ratio that was -- that was calculated earlier.

So, the first step is to take that one thousand dollars ($1,000) of generation and transmission costs and multiply it by those percentages to get your energy and demand components. So you can see, I hope my math was right, six hundred and sixty dollars ($660) for energy, three hundred and forty dollars ($340) for demand.

Now, transmission costs are allocated 100 percent demand related. So what we've done is we take those transmission costs, in this case a hundred and fifty-three dollars ($153) and subtract that from the total demand component that we calculated of three hundred and forty dollars ($340). And again, hoping my math was right, that leaves you with a hundred and fifty-three dollars ($153) left on the demand side for the generation function.

So, if you recalculate those two (2) numbers you can see that what we have is an effective system load factor of 81 percent to energy and 19 percent to demand. And again, Mr. Wiens' discussion earlier about how the system works and stuff and how the future is more energy related versus demand related, bears out that fact with this calculation.

Now in terms of our other functions, sub-transmission. Again we allocate that a 100 percent demand. Distribution we split between demand and customer costs, and that's to take into account things like the customer meters and service drops and so on.

And then finally, customer service costs are re -- are allocated totally on customer related allocators.

Now in terms of allocation specifically and how we allocate those energy demand and customer costs, on the generation side, we allocated as we saw on the previous slide, both on energy and demand. And for -- and for energy it's the class annual energy which includes transmission and distribution, distribution losses, and we'll get into losses a little further on in the presentation.

In terms of demand what we're using is what we call the 2-CP method, which is basically the average of the summer and the winter peaks. And again I'll show you a sample calculation of that coming up.

On the transmission side I'd mentioned that we allocate that a 100 percent to demand, and we use that same two 2-CP allocator that we use for generation.

Now on -- now on the other functions what we use is what we call non-coincident peak, or NCP. So we use that on the distribution side and then our sub-transmission side, the distribution side and also some customer costs in the distribution side.

And then finally, in terms of allocation of net export revenues, it's based on class share of generation and transmission costs.

So here's a -- just a -- again, using fictitious numbers, just a sample allocation of how we -- how we arrive at that. Energy is fairly simple, we have a Class A and a Class B, they both use about five hundred (500) kilowatt hours a year. So you can see that the class share is 50 percent to each.

Now on the 2-CP, in iterations of the cost of service in the years past, what we had used is just that single winter peak. So what we would use is the class shares, if you look on the right hand side, Class A would get about 43 percent and Class B would get about 57 percent.

But what we try to do with the 2-CP, is integrate the full year characteristics of each customer. And so we take the average of those two (2). So again you can see for Class A they have a winter load of fifteen (15), but not such a high load in the summer time. So we take the average of that and it's eleven point five (11.5), and this -- similarly with Class B we do the same calculation.

And so if you look over at the side, as I'd mentioned, in iterations past, it would be 43:57, but by taking into account the total load over an annual basis of each of these customer classes you -- you've effectively changed their allocation on the demand to about 34 percent to Class A and about 66 percent to Class B.

Now there's a whole host of -- and this certainly isn't an exhaustive list, but there's a whole host of items that we have to deal with in the cost of service. So what I've -- what I've done here is I've made a few slides showing how we treat these -- these various items in the previous version, and then a little further forward after we get into the current method, I'll show you those same items and how they relate in the current method.

So first of all in the -- I believe it was the GRA where there was a lot of talk about Winnipeg Hydro, because Manitoba Hydro had just acquired Winnipeg Hydro. So there was some concerns because of the -- the timing and when we did our cost of service study, where we didn't have a lot of the Winnipeg Hydro data integrated, and put forward through to our study.

Well, for '06 that matter has -- has been totally resolved. That includes both proper functionalization of costs, load data and similar type things.

Again, uniform rates. Revenue loss associated with the uniform rates legislation has been put in all these scenarios, and to reiterate, that affects the residential, general service small, medium, and of course street lighting classes.

Generation using marginal costs. Well, in the previous method we're not using marginal costs at all. So that's not a factor.

Transmission and distribution losses. Transmission losses are -- are calculated for us and in the IFF, so that's a direct input into the Cost of Service Study, whereas distribution losses what we do is we take those deliveries through our transmission system, our common bus, and then subtract that from what our customers actually received. And the difference, where classified, are calling distribution losses.

MR. BRENT MCLEAN: On that -- on that page, in terms of the generation costs using marginal costs, can you just expand on how you define marginal costs and what numbers you use, that sort of thing?

MR. CHIC THOMAS: Maybe if I could defer that until a little later, Brent, if you don't mine?

So again continuing with some of the items that we look at in our cost of service study there's -- there's mitigation costs. We functionalise that as a generation capital cost because all these costs are capital related. So they'll show up in the cost of service study as interest and depreciation.

We have fuel and power purchases. So 100 percent of import costs and a proportional share of water rentals and fuel costs are deducted from gross exports. So I'll get into the definition of gross and net revenue export in a moment.

Firm and opportunity export sales. Again as I've mentioned we don't have an -- an export class in the previous method.

Now, the definition and allocation of net export revenue. Gross export sales are defined for us in the IFF and I was -- and I was -- as -- as I was explaining to Byron what we do is we subtract that, the assigned portion of what we deemed applicable to exports for -- for water rentals and such and 100 percent of power purchases.

So that the gross export number less, in the case of the 2006 study, that $107 million, we deduct and that's for cost of service purposes becomes our net export revenue.

(BRIEF PAUSE)

MR. CHIC THOMAS: In terms of the forecasted water flows the cost of service study is always usually done two (2) years on the second year of the IFF. So in the case of the '06, we are using the IFF 2004 and in all cases we're using water flows on an -- median inflows. That -- that again is given to us in the IFF.

Development of class allocators. So again as I showed you previously generation and transmission is based on the system load factor. Specifically for generation it's annual energy and 2-CP demand, again the average and summer peaks.

Transmission is 100 percent demand again on that 2-CP allocator. For sub-transmission again 100 percent demand NCP. Distribution NCP and customer accounts and for customer service customer accounts.

Now -- now I should mention that for customer accounts we do have weighted and unweighted customer accounts to allocate certain customer costs.

And finally, in terms of treatment on the previous method, use of surplus energy program rates for marginal costing. Again no marginal costing in the previous study.

MR. BRENT MCLEAN: Could I -- question of clari -- just back on page 16 Forecasted Water Flow Conditions. When you use PCOSS-06 the costs allocated are based on IFF on the 06 IFF right, not -- not the '04 IFF?

MR. CHIC THOMAS: Correct. We're using the -- yeah, the IFF 04 and it's ten (10) years I think in the future and we're using yes, the second year for 2006.

MR. BRENT MCLEAN: And you're using those costs and those water flows?

MR. CHIC THOMAS: Correct.

MR. ROBIN WIENS: So -- so you're -- you're two (2) years behind in your forecasting in effect, in your cost of service? I -- I was just wondering why you wouldn't use the most current cost of service or IFF.

MR. CHIC THOMAS: Timing is -- timing is one (1) issue. The IFF is usually approved October by our Board of the following year that it was produced so -- so for IFF '04 it would be approved in October. Do you have anything to add to that, Robin?

MR. ROBIN WIENS: This is the 2006 cost of service study. Much of it was prepared earlier this year. In fact we filed some preliminary results with the Public Utilities Board in February of 2005 and this is the same study. It is based on the financial forecast that was made and approved in October or November of 2004.

In order -- if we were to use the IFF for 2005, we would still be in the process of preparing that cost of service study.

MR. BRENT McLEAN: And just to be clear you used the '06 numbers that were in the IFF '04. And -- and I suppose normally there aren't a lot of differences between the numbers in -- I mean the forecasted numbers two (2) years out in the IFF anyway.

So the numbers are probably pretty close. Like if I was to look at -- at the current IFF and compare it to the '06 numbers in IFF '04, presumably the numbers would be pretty close anyway.

MR. ROBIN WIENS: Well they do change from forecast to forecast because, you know, we -- we identify new needs, some old needs may no longer be applicable. So the forecasts will be different.

The total cost -- forecast of total cost is likely going to be different in IFF '04 versus IFF '05. However, because we use a prospective basis and we base things on medium water conditions in the second year.

While the costs may change you would not ex -- you would expect to find some stability of the results of the cost of service study because we are looking at -- we're not looking at actual conditions where we may have had a drought in one year and a flood in the other.

We're looking at medium inflows two (2) years into the forecast. So in affect we -- we normalize for a lot of those things. And you will have differences from year to year in cost of service results for -- for various reasons.

But for the major classes, the results are -- are surprisingly stable. Even if we have a significant change in total costs from one IFF to the other. So --

MR. BYRON WILLIAMS: So -- if I could stop you. It's Byron Williams.

MR. ROBIN WIENS: Sure.

MR. BYRON WILLIAMS: Just in -- in terms of surplus energy program, what -- what are the SEP costs based on?

MR. ROBIN WIENS: I'm going to give you -- I'm going to give you an answer that is a general answer. I'm not going to refer to specific numbers in this. We will probably want at some point to get to the specific numbers and we'll certainly be prepared to make those available to you.

Manitoba Hydro has offered some variant of the surplus energy program. I believe since about 1991, I could be out by one (1) year further back or one (1) year forward on that.

But it's roughly that time period. And we've been through a couple of three (3) iterations of that program. For the last at least five (5) years and I think going back more than five (5) years, we have offered surplus energy on the basis of -- we file weekly prices that are -- are anticipated returns in the export market or alternatively our cost of imports or thermal, if that's going to be the source of supply for the customers taking SEP.

And we file those on a weekly basis with the Public Utilities Board and they're approved on an interim ex parte basis. I then from time to time those are reviewed.

Now, we also as part of managing this program at the end of the week we go back and we determine what the actual prices were or the actual values of either export sales or imports if they were significant in supplying that load or -- or thermal generation if -- if that was the source of the supply.

And we provide a -- and we maintain a running tally of the after the fact, we call them, costs. We split because of the way we -- we've set up the program, we price surplus energy into three (3) periods which are peak period, shoulder period and off-peak period.

And two (2) different seasons, summer and winter. And we define the peak period slightly different in each of those -- in each of those periods. The off-peak period is always seven (7) days a week from 11:00 p.m. to 7:00 a.m.

The shoulder and peak periods are the remainder of the hours. And depending on the season, the peak period may occur during the course of the whole day from noon until 8:00 p.m., that would be the summer season. Or the peak period may be from 7:00 a.m. to 11:00 and then a second peak period from 4:00 p.m. to 8:00 p.m. and that would be the winter season.

And we have approved prices to -- to charge our customers in each of those periods. And in addition we go back and we determine what the actual export revenue was during those periods on a per kilowatt basis and we maintain those.

And that database is how we have -- what we have used in order to come up with the S -- what we call the SEP based marginal value of generation.

I don't -- I do not have all of the numbers, and I do not have with me the specifics in terms of how we compile and analyse those numbers, but we will make those available.

MR. BYRON WILLIAMS: Just thank you for that, Mr. Wiens, it's Byron Williams again. If I recall the -- the last Cost of Service Hearing, there was concerns in terms of using marginal costs related to confidentiality and other concerns.

I wonder if you can just help us to understand why these -- the SEP costs are considered a -- an appropriate proxy or measure of marginal costs?

MR. ROBIN WIENS: Well they relate -- they relate to what we believe was the actual cost to serve that surplus energy load. It is served in one (1) of three (3) ways, we divert sales from the export market, and the market price is that. That is the value of that energy as determined in that market. Or we have to generate, using natural gas or coal fired generation, and we know what that costs us on a per kilowatt hour basis.

Alternatively we may have to actually import to serve that load and then we -- that is an out of pocket cost. But that is the value of that energy at that time, so it is -- we think it is a good proxy for marginal costs, it needs to be of course kept in my -- the proxy is short term marginal costs, it's not long term marginal costs.

And if you know about the relationship between those two (2), typically a long term is going to be higher, but in a market where scarcity is an important factor in short term, sometimes the short term marginal costs can go higher than the long term marginal costs.

We -- so we believe it's a good proxy. We have also cross-checked it against market reported data from -- from a market reporting source, Plats (phonetic), and we have determined that, you know, from hour to hour there are obviously differences. But over a long enough period of time it correlates quite well with the -- with the Plats data, which is what we have -- actually when we presented the -- the Cost of Service Nuer (phonetic) Report back in 2004, it was based on the Plats information.

We use it -- we have looked at it and averaged it out over a five (5) year period, because I think you can get more representative results the longer the term that you -- that you take a look at. Of course we do escalate for inflation, so we try to say that it's based on the recent past, but with the oldest results escalated for inflation.

As to the issue of confidentiality or not, we do believe that trying to look at our marginal costs going forward, because those are our predictions, those are what we think is the reality going forward, provides information for other participants in our markets that would disadvantage us. So we prefer to keep that commercially sensitive.

What we -- what we are using here is information that we have gathered in the past, so it pertains to the past. And information that we would supply the Public Utilities Board in any event, for when they want to review the -- the ex parte orders on the Surplus Energy Program.

So we feel that this information addresses -- or successfully address the confidentiality question as well.

Does that answer your question, Byron?

MR. BYRON WILLIAMS: It's a good start.

MR. ROBIN WIENS: It's never enough.

MR. BYRON WILLIAMS: Just one (1) follow up question. You mentioned that you'll -- you'll make the numbers in the calculations available, or at least I understood you to say that.

How long would that take to make those available?

MR. ROBIN WIENS: We could certainly, if -- if we're looking at -- if we're looking at only one (1) round of Information Requests, we would -- we would expedite that.

Probably -- probably a week, probably a week. If we're looking at two (2) rounds of Information Requests, we could certainly have it available in the first round.

MR. BYRON WILLIAMS: Thank you, I'll ponder that. I'm trying not to be an advocate this afternoon, so I'll try not to reply.

MR. CHIC THOMAS: Moving right along.

So, now let's move to the current method and highlight some of the differences between it and the previous method.

So one thing I neglected to mention in the previous version is that -- is that a portion of HVDC is included in generation. Generation classification and allocation is based on marginal cost now and -- and as Mr. Wiens so eloquently referenced, those -- those things are determined from our SAP rates.

For transmission what we've done is we've classified into the -- we've classified the costs into energy and demand based on the purpose of that line. So all of our export lines we're saying we're going to allocate that on energy.

All of our domestic transmission lines we'll continue to allocate those 100 percent to demand. I have a sample calculation of how we derived that -- that you'll see in a moment.

One other -- we've created an export class and we further segregated that into a firm and an opportunity sub-class. The other functions, sub-transmission, distribution and customer service, we're treating in the same way.

MR. ROBERT MAYER: Just before you go on. The top bullet on that page:

"As in previous method generation
includes high voltage DC."

You said a -- when you -- when you mentioned it you said a portion of high voltage direct current costs.

MR. CHIC THOMAS: Yes. That's --

MR ROBERT MAYER: That's just excluding Dorsey, right?

MR CHIC THOMAS: Correct. And I should have made that more explicit, thank you, Mr. Mayer, in the slide.

MR. BRENT MCLEAN: How do you define -- how did you define firm -- a firm customer versus an opportunity sale?

MR. CHIC THOMAS: I'll defer that to Mr. Surminski if I -- if I could, he's the expert on that.

MR. HAROLD SURMINSKI: In general we define -- maybe firm is -- is not quite the right terminology here, but it's a long-term sale or a -- a transaction that is negotiated well in advance for delivery into the future and it includes consideration that these are dependable resources that we are selling.

So, the word 'firm' really means dependable. It's a -- it's a sale from our dependable resources which we can supply under all water flow conditions. So generally that's the classification, a long-term transaction negotiated, say with delivery starting one (1) year into the future would be considered a -- a firm long-term transaction.

Everything else is opportunity. Everything else that depends on -- on the water supply known in the short term. If you have good water supply above dependable in the short term you can negotiate short-term firm sales.

I think there is a -- a confusion sometimes, Well what about short term firm-- what I would categorize as short-term firm, are these really included in this class of firm. They are not.

Something that -- that you find, you know, you have the water conditions in the short term to negotiate a six (6) month sale just because you know in the next six (6) months you will have a water supply and the energy for that, that is not considered in this category of firm.

MR. LEN EVANS: So that's an opportunity sale?

MR. HAROLD SURMINSKI: Yes, that's correct. Everything else is opportunity sales.

MR. LEN EVANS: I wonder if I could ask you a question about the term "interruptible", and you still use the term -- I mean, it's -- I always understood it was either firm or interruptible; is that still applicable?

MR. CHIC THOMAS: Interruptible or spot sales they're sometimes called, they are generally in the opportunity class. The opportunity class that we consider include interruptible -- interruptible just means that that firmness component no longer exists.

But firmness has -- has a special meaning in the electrical world, where you may be required to provide reserves and you're obligated to supply power under all conditions. So that's why you have to be careful in using the terminology of 'firm', versus a long term transaction.

MR. LEN EVANS: I think I understand the definition of "firm," but it was the use of the word interruptible, and I think you were using another term, operating category as well. So I'm just trying to get clear in my mind the use of the word interruptible. But you don't use it?

MR CHIC THOMAS: I don't use interruptible, it's one (1) of the categories of power in opportunity. And -- and spot -- spot sales are -- are more -- a better description. I think currently we use spot sales in -- in sort of the real time market. There's the day ahead market, the real time hourly market.

So, interruptible would -- would generally maybe fall into that class, where you don't know that you had the power until the hour, the next hour. And you only commit yourself to one (1) hour at a time.

And you could -- the customer could be interrupted within that hour also, if -- if supply in the system, there's a problem with the unit going out.

MR. HAROLD SURMINSKI: Okay, thanks.

MR. PETER MILLER: Yes, I have a couple

questions. One (1) is, what is the logic for all export lines being allocated as energy, given that the export capacity is a bottleneck which prevents you from selling more of your power than that capacity at -- at peak rates?

MR. ROBIN WIENS: Well, this is a recommendation that was given to us by the NERA folks in the -- in the report that we filed in April of 2004.

But it has to do as well with the fact that these export lines allow us the ability to transfer energy on a year round basis to our export customers. And in addition, provide us with a life line in years like 2003, when we need to get energy into the system because of a shortage of water.

That's my understanding of that rationale anyway.

MR. PETER MILLER: And -- and my second question. I -- I'm not sure I understand what is meant by marginal cost weightings and generation classification and allocation.

MR. CHIC THOMAS: Again, as I've mentioned to Brad, maybe we'll defer that. I have a slide --

MR. PETER MILLER: Okay, sure.

MR. CHIC THOMAS: -- that shows -- shows

how we get into that.

MR. BILL HARPER: Excuse me, I actually just had one question, it's Bill Harper. I just wanted to follow up on Mr. Surminski's comments.

Your discussion about firm being greater than one (1) year, and you know, in the short term even having firm sales as opposed to opportunity, sounds very much like the sort of the types of distinctions that are made in -- in the MISO Tariff itself, in terms of long term service being great -- being greater than one (1) year and a short term sort of services being -- being less than a year.

I was wondering, is -- is there any similarity between your -- your determination as to what's firm and what's opportunity, as to what would -- as to what would classify say under a long term point to point service, under the MISO tariff you might have to purchase in order to do the export, as opposed to some of the shorter term services you'd be purchasing?

MR. HAROLD SURMINSKI: No. The MISO market is -- is only a balancing market for -- for short term energy, long term tariffs are -- and arrangements are not included in that market at all. Bilateral sales are -- are just contracts between mutual parties.

So, the MISO market does not -- does not consider long term exchanges, that's -- that's not part of -- of that whole system.

MR. BILL HARPER: Well, I was thinking more about the transmission tariff itself actually, that you -- and your priority arrangements there, but something -- something we can maybe pursue later I think.

MR. CHIC THOMAS: Any other questions? Okay. Continuing with the current method now.

How we -- how we created and the treatment of the export class now.

So as I said, we split the export class into two (2) sub-classes, the firm sales and the opportunity sales. Now for the firm sales, we're allocating costs to them in the same way as domestic customers, very much like the original NERA method. But we've also now created an -- or an opportunity export sales sub -- subclass.

And for them what we're doing is, again, as of the previous method, we're assigning them a portion of variable costs, water rentals and so on and so forth. Again, this percentage is lower than in the NERA method because we don't have the whole class in here.

In terms of the -- the split we use between the two (2) classes, we used the average eighty-six (86) year flow sequences and then of those eighty-six

(86) years we just took five (5) years into the future.

As you can see here, '06/'07 through '10/'11, and averaged those out. And when you do that calculation it yields firm sales about 55 percent and opportunity sales about 45 percent.

MR. LARRY BUHR: When you did the marginal cost analysis you -- you used the time period from '99 to 2004. Why would you not have used the same time period for the -- the split of export and -- and opportunity?

MR. CHIC THOMAS: One (1) reason is -- is those prices are a little variable and I think we're encroaching upon the confidentiality of looking forward to what we think our prices might be.

MR. LARRY BUHR: A follow-up question of that would be: Isn't the current situation quite different from what you're showing as marginal costs then?

MR. ROBIN WIENS: Marginal cost estimates are based on SEP prices looking backwards to 1999, as I say, because those are the best available information that we could provide you and be assured that we were not putting commercially sensitive information out into the public.

In the case of the opportunity and firm

sales split I -- I don't know this for sure, but I suspect that we would have a very different situation looking backward five (5) years than we have looking forward five (5) years. Our initial intention had been to base it on what we expected in the year for the cost of service study.

There was some concern that that would be putting commercially sensitive material on the record so we determined that the -- the way we could best come up with what we thought was a reasoned split between firm and opportunity and -- and not have it -- have the -- these commercial sensitivity concerns, was to do it on a five (5) year average basis looking forward.

We're good, Larry?

MR. LARRY BUHR: Okay. So --

MR. ROBIN WIENS: Yeah. Mr. Surminski reminds me that another -- another concern was that into the past we would be looking at actual flow years and there may have been some distortion as a result of what the actual flows were.

(BRIEF PAUSE)

MR. CHIC THOMAS: So, I'll take you through our --

MR. BRENT MCLEAN: Could I -- just one (1) more question, sorry.

MR. CHIC THOMAS: Sure.

MR. BRENT MCLEAN: Going back to 19 -- talking about the split, you know, the allocation of -- of costs to firm export customers and you say that the costs are allocated in the same way as domestic classes.

And yet when you look at the -- like, the -- the material you filed, there's, you know, there's functionalization costs and classification costs, there's no export class there in the -- in the material to indicate what costs have been allocated.

Is there a reason why an export class isn't there if they're allocated costs in the same way that other domestic classes are?

MR. CHIC THOMAS: Well, the -- well, the firm portion have been included in the cost of service study in terms of those costs because then they allocated those costs back. It's the opportunity that we separate out.

MR. ROBIN WIENS: The -- the firm sales are treated as a -- in the same way as a domestic customer class. We don't identify the costs in the functionalization process. We functionalize the cost into generation and transmission. We classify them according to the relative marginal cost method.

And then we apportion them among the customer classes including the export class on the basis of their relative use of energy in each of the time periods.

MR. CHIC THOMAS: So we'll go through another sample calculation of how we're applying those marginal cost weightings to our generation energy

So as you can see on this slide we've got our same Class A and Class B customers and they're both using five hundred (500) kilowatt hours a year for a total system of one thousand (1000) kilowatt hours.

So now what we do is we take that same energy -- and the next line please -- so in the first two (2) columns on the right it's that exact same energies that I just showed you previously.

Now here's our marginal cost ratio that we've determined and -- and we'll be supplying the calculation to that. And so what we've done is -- you can see that we've got the four (4) peak -- the four (4) seasons: Summer on peak, summer off peak, winter on peak and winter off peak.

And you can see by virtue of the weightings that our winter on peak has been determined to -- to be when the costs are the highest.

Similarly the summer on peak is the second highest. Our summer off peak is what we used as the basis to compare it to because we know that's the lowest cost period. So what we do is we take those energies that I just showed you and multiply it through to those numbers.

So you can see that the important thing to note on here is that we start off with a weighting between Class 'A' and Class 'B' of about 50 percent and then you apply those marginal cost weightings and what you've done is you've redistributed those costs, 52 percent to Class 'B', 48 percent to Class 'A', recognizing that this class is using energy at a higher cost period than Class 'A'.

MR. ROBERT MAYER: Why does it cost more to generate energy in the winter?

MR. CHIC THOMAS: Generate energy when, I'm sorry, Mr. Mayer?

MR. ROBERT MAYER: In the winter. You're showing higher costs, your seasonal marginal cost ratio is lowest in the summer, off peak, and then your winter off peak is significantly higher. I -- I'd like to know why it seems to cost -- it costs more to generate energy in the winter.

And I want to know whether the difference between the on peak and the off peak, no matter which season it is, is that based somehow on line losses or why does it cost more on peak than off peak?

MR. HAROLD SURMINSKI: Marginal costs are -- are really values to the system, so they're really the value of the last increment of energy to the system, so it's reflected in value in the export market.

And reason for winter versus summer, our system is -- is hydraulic and it's difficult for us to transfer water from the summer period when we have our major inflows to the winter period when we have our major or highest demands.

So just the difficulty of -- of getting our water supply into the winter months makes energy more valuable in the winter period.

MR. ROBERT MAYER: So it's based on the value of the energy, not your actual cost of production?

MR. HAROLD SURMINSKI: Yes, that's correct.

MR. CHIC THOMAS: Any other questions on our -- how we apply our marginal cost weightings?

MR. BYRON WILLIAMS: Mr. Thomas I was waiting until you got to this slide about classification of transmission costs. And I want to -- we don't have to go back but it's slide 18, you talked about how transmission was classified into energy and demand based on the purpose of the line.

And I wonder if you can explain to us how you define when something is an export line? Like when does it -- where does it start and how that process is done?

And also, is that on the record or in the filing? Is that information on the filing somewhere?

MR. CHIC THOMAS: The detailed calculation of it, no, it is not. But from a -- from a physical point of view it's basically the -- the transmission lines that directly tie to our Provincial borders to the east, west or to the south.

Now, in our financial reporting system, SAP, we've specifically identified those specific lines. So what we do is we call them export lines. And then it's from this financial reporting system that we can extract the costs, depreciation and operating, for example.

And then, based on that, we're doing the percentage split that you can see on this slide, and -- and if you'd like to see a more detailed calculation on that, we can certainly provide that.

MR. BYRON WILLIAMS: So that's something we're going to probably want at some point, which gets one back into the first or second round interrogatory debate, but okay.

MR. CHIC THOMAS: Probably the first, yeah. So -- so again, continuing on with that thought.

MR. DOUG BUHR: I'm sorry, Doug Buhr. I -- I guess I'm a little slow here. I understand about transmission lines direct to the Manitoba borders, but where do you start counting it from; the transmission line, the export line? Does it -- do you start it from Northern Manitoba? Do you -- is that all an export line? Or do you start it from Winnipeg, or do you start it from where?

MR. CHIC THOMAS: I would -- I would have to double check on this, but my understanding is, is that line starts from the -- the last station where that transmission line originates from -- from.

So for example, we have a 500 kV line that goes to Forbes, Minnesota, for example. Starts -- well it starts at Dorsey. So that would be -- from Dorsey to the Provincial Border, would be that line. And it's the cost from that that we define as the export line.

MR. ROBERT MAYER: Do all the lines, all those export lines start from Dorsey?

MR. CHIC THOMAS: Not all of them, no, sir. Well I guess -- I mean indirectly, a lot of -- I'm not sure what the percentage is, but a large percentage of our bulk power from the north is coming from Dorsey. So I guess in some way it would have some --

MR. ROBIN WIENS: Perhaps I can help a little bit on this, Mr. Mayer. I would say that most of the capacity that serves the export markets begins at Dorsey. We do have lines that go into Ontario, and into Saskatchewan, and I cannot -- I cannot tell you precisely at what point each of those would be considered an export line.

I don't have a map on the transmission system here with me. But it would be as Mr. Thomas says, the -- if there is a sub-station somewhere between the origin of generation and the -- and the Provincial border, Ontario or Saskatchewan, it would begin at that sub-station and go to the border.

MR. ROBERT MAYER: So for example, I believe that there is an interconnect somewhere around Flin Flon. I know that there is another station at Flin Flon. So the export line would run from Flin Flon to the Saskatchewan border, which is about fifty (50) feet?

MR. ROBIN WIENS: Subject to check, that's correct.

MR. CHIC THOMAS: So continuing with our transmission classification. As I mentioned to Mr. --

Mr. Williams, is that after we go through our -- our financial records, and I -- and have identified those lines that are domestic, and those lines that are export, we come up with these two (2) lines here, and then we calculate a percentage.

So, you can see we've got a percentage in each of the cost components. And then what we have though is we have certain common costs that you can't say are directly related to export, or directly related to domestic.

So what we do is we accumulate all those common costs, and then a portion, either the domestic or the transmission customer, their appropriate portion of these so called common costs.

And you can see that's reflected below in that extra two hundred and nine dollars ($209).

And then you add all that up and then those are the two (2) numbers that you see that we allocate costs in the -- in the current method, in terms of the generational classification.

Now we -- now we went through all those items for the previous method of -- of how we treat them in the Cost of Service. So by contrast now, we'll just go through the current method and see how those things differ.

So for Winnipeg Hydro and uniform rates, there's no difference. Generation costs using marginal costs, and as we've already talked about, we are applying marginal -- marginal cost ratios based on average SAP data.

And again, '99 to 2004, adjusted for inflation and then applied to those seasonal periods that we showed you in a previous slide, the summer and winter, on and off peaks.

Transmission and distribution losses applied in the same way in either version. Again, mitigation costs, same -- same treatment. Fuel and power purchases, this is -- this is where we differ a little bit, and with the creation of the export class, fuel and power purchases are applied as follows.

Domestic and firm, domestic customers and firm export sales are allocated generation costs that include a portion of these fuel and power purchases.

Now, opportunity sales are assigned their proportional share of these costs.

MR. BYRON WILLIAMS: Mr. Thomas, it's Byron Williams, sorry to be a pain.

Just going back to the export line question, in terms of transmission. The statement at page 18 says:

"All export lines are allocated on
annual energy."

Does that mean those costs are allocated on annual energy to all classes of customers or to the export class?

MR. CHIC THOMAS: All customers.

MR. BYRON WILLIAMS: Thank you.

MR. CHIC THOMAS: I think we're one (1) more. Yeah, four (4), Brenda. One (1) more. I think that's where we are.

So again, on the firm and opportunity sales, we've got the firm exports, and again, allocated generation and transmission costs in the same way as our domestic classes. And opportunity exports, they're assigned only the variable costs. And there's no allocation directly to this class. All they get is their variable costs, which is assigned to them.

In terms of the definition of -- definition and allocation of net export revenue in the current method. So again, we start with the gross export revenue that -- that we have in the IFF, and then from that we -- we back out whatever was allocated to the firm class, plus the assigned costs on the variable class, and that gives us our net export revenue.

Now, by -- now by contrast, if you compare that to the previous method where you're making that one (1) assignment of costs to -- to the export class up front, well, when you're allocating costs to the export class that becomes a lot.

It's significantly higher, I believe, if memory serves me correctly; 7 percent was -- was assigned to export as a cost, where as allocating costs, it works out to about 21 percent.

MR. BRENT MCLEAN: Mr. Thomas, are there any costs at all related to firm export sales that are directly assigned, or does it all come through the allocation process? Do all costs come through the allocation process?

MR. CHIC THOMAS: There -- there is some that is assigned, for example, we pay things like NERC fees, which is National Energy Research, that's considered -- we have some fees to MISO and stuff like that. That would all be in that apportionment of our water, fuel and power sheet.

So, again, it would be allocated to the firm and a portion assigned in the variable.

MR. BRENT MCLEAN: I was thinking more, like, you must have people internally that are -- they work full time on negotiating and spot contracts and things like that, their costs. Do those costs get directly assigned to the firm export customer in the process or do they get thrown into the hopper and then through the -- the allocation process side?

MR. CHIC THOMAS: More the -- more the latter. And we have looked at that because, you know, you're referring to -- yeah, we have external power marketers and so forth that, as -- as you say, deal with doing the export market.

We have looked at those costs but relative to the whole generation and transmission pool it's insignificant. So, A) it's not going to materially affect the results if we were to make that direct assignment and B) there is some duality to their purpose.

I hate to go back to the drought year but, for example, their role would be more in securing power supply domestically than it would be selling power domestically.

Okay. I think, yeah, we're through that.

So development of class allocators. Again, as I've showed you in a previous slide, we had marginal cost ratios which we apply to this seasonal energy for our general allocator. On the transmission side, again we've classified that depending on the purpose of that transmission line, export versus domestic.

All other functions, sub-transmission, distribution and customer service remain the same. Excuse me. And as I've showed you in that previous slide, when we applied those marginal cost weightings, I've shown you the weightings again for the -- for each of the four (4) seasons.

So as I said at the start of the presentation, Order 10104 directed us to supply four (4) versions of the cost of service. One of them was this generation vintaging method. What it is, is essentially it's the same as the NERA method but what we did is we just made accommodation for the split between the low-cost resource and the high-cost resource.

We defined, according to -- to how TREE/RCM had defined it in the Hearing, was our low-cost resource would be -- our low-cost resource would be all Winnipeg River plants, all other Manitoba Hydro plants is deemed the high-cost resort -- resource, I'm sorry.

MR. ROBERT MAYER: I have a question here, and I realize this may well be irrelevant because there doesn't seem to be anybody encouraging at this point that vintaging method, but it strikes me that there are at least three (3) separate and distinct generation groups.

First is clearly the Winnipeg River. The second, however, appears to me to be the Grand Rapids in Upper Nelson, Grand Rapids Kelsey (phonetic), which were built not at the -- I suspect not nowhere near the cost of the Limestone Kettle and Long Spruce (phonetic).

How did you choose just, when you were vintaging or choosing vintaging, why did you lump the Grand Rapids Upper Nelson in with the rest of the Nelson River, Lower Nelson costs?

MR. CHIC THOMAS: A couple reasons for that. Number 1, when this whole idea of generating vintaging had come up from TREE, they had identified Winnipeg River as the low-cost resource. So -- so to directly target their initial concern, we used -- we assumed that was the low-cost plan.

And because we didn't want to make it overly complex and getting into a three-tier system according to cost, we just lumped all the other costs in as the so-called high-cost resource.

Okay. So -- did I miss that one again? Oh, I don't have it in mine; that's why. Yeah. Okay. I'll wing it.

So I should have talked about this one first because it ties into what I just said about the generation vintaging, but excuse me for that.

But going back to the NERA method it's the same as the current method except that there's no separate subclasses for the export class. A single export class is created which is allocated costs to generation and transmission in the same way as domestic customer classes.

So again as myself and Mr. Williams talked about is that what happens is to account -- because they're being allocated costs, what was previously assigned or that 107 million is now added back into a generation cost, which is allocated to all customers.

So the next couple of slides are just some tables about showing some various results.

Now, this first slide is just showing you what RCC's are prior to any allocation of export -- export revenues. So we've got the previous method and the current method.

And you can see that with the exception of area and roadway lighting all our RCC's are far below what we call the zone of reasonableness or ZOR. And this is prior to the application of export revenue.

And then with the application of export revenues we're showing you here the results of the four (4) methods that we submitted as part of Order 101/'04 that we submitted on February 1st, 2005. So you can see that we've got our RCC's for all classes, so from the previous method to the NERA method, our current method, and finally the generation vintaging method.

I'll just draw your attention to a couple of things, the NERA and the generation vintaging method. You can see that -- that the results are very close and -- and that and another -- and for other reasons we -- we haven't been supporting the generation vintaging method.

And again you can see the previous method and the current method, they -- they do differ. And in all cases the major driver of the shift in RCC's is how we're allocating net export revenue.

And again to reiterate, on the previous method it's on the basis of generation and transmission costs and on the current method it's on total allocated costs, not just generation and transmission.

MR. BRENT MCLEAN: Does the allocation of the -- I mean the first charge on the net export revenue for the uniform rate adjustment, does that have an impact on the RCC's for the residential consumer as well?

MR. CHIC THOMAS: It does have a little impact, but not overall and I think I -- if you'll just excuse me I think I do have that number.

(BRIEF PAUSE)

MR. CHIC THOMAS: Maybe in -- in the interest of time I'll find that for you later, Brent.

Well, I guess that's it, albeit a little truncated. So if you have any further question or comments the floor is open.

MR. BRENT MCLEAN: Just a general question. In -- in terms of coming up with your current method, your recommended methodology, did Manitoba Hydro look at some other utilities such as, perhaps, Quebec Hydro who I think also has a significant export revenue benefit and I don't know, maybe BC Hydro?

Did you compare your recommended methodology to some other utilities?

MR. CHIC THOMAS: When -- when NERA was commissioned to -- to do the -- do the study they did undertake to do a survey of -- of utilities both nationally and in -- in the United States. Memory is escaping me the exact treatment. Mr. Wiens might be able to elaborate on that, but I'm not exactly sure right now what that survey resulted.

MR. ROBIN WIENS: I -- I don't have any detailed recollection of it but Mr. Thomas is definitely correct. We filed that study with the Board and all the Interveners I think that are here today in the April 1st of 2004 and there's an extensive review of about twenty

(20) utilities and how they deal with the classification and allocation issues that we're talking about here.

It includes BC, it includes Quebec, I believe it includes Ontario and it includes a number of hydraulic utility organizations in the United States as well as some of the major public purpose developments in the United States. So it's quite extensive.

MS. PATTI RAMAGE: If I could perhaps help. The NERA report that Mr. Wiens referred to is contained -- is found in the back of Appendix 11.2. And the reference is at page -- it begins at page 19 of that report and there's a table that follows listing the various utilities that were surveyed.

MR. CHIC THOMAS: Any -- anything else?

MR. LARRY BUHR: Just one question, going back to page -- sorry, Larry Buhr. Going back to page 22, the numbers you were showing in the -- in these various categories, are they taken directly from your -- from your overall work process?

MR. CHIC THOMAS: Sorry, Larry, I should have clarified that when I went through that. No, these are -- the proportions are approximately the same. But the numbers are just representative figures because obviously in the cost of service they are much larger so it would have cluttered the page a little more.

But yeah, the numbers are just fictitious but the proportions that I'm showing are approximately what happened in actual fact.

MR. LARRY BUHR: No. It made me look -- almost to think that you were actually dealing with total generation and transmission rather than just transmission when I look at the numbers you had.

MR. CHIC THOMAS: Yeah. No. Yeah, I'm just making up numbers there.

MR. LARRY BUHR: Thank you.

THE CHAIRPERSON: Mr. Miller...?

DR. PETER MILLER: Yes, a few questions. The inverted rate study and time of use study suggested that there should be a movement from an 'E' cost to a what I'm calling an 'M' cost, that is marginal cost would play a bigger role.

Do you consider this to have done that or do you see a further transition if that recommendation were to be carried out?

MR. ROBIN WIENS: Dr. Miller, the study that we filed earlier this summer on inverted and time of use rates, was directed at the issue of rate design. And marginal costs definitely figure largely in that study in terms of rate design.

It is also true that you can carry out a marginal cost of service study if you have the time and the resources and the need to do it. We didn't see the NERA report as directing us to -- to carry out such a study.

And while we have some idea regarding marginal cost particularly if some of the functions we don't even have the complete information required to do such a study.

DR. PETER MILLER: You say you didn't -- you didn't take their report as -- as directing that. How -- how do you interpret -- they did make some reference to it and I'm just -- have a vague memory of that.

How do you interpret their vague reference -- my vague reference to it?

THE CHAIRPERSON: Professor Miller, if I can break in, I think that's for the -- when we get to the hearing.

DR. PETER MILLER: Okay.

THE CHAIRPERSON: Like this is just a technical session on the COSS system. I just want to keep it on that plane if we can.

DR. PETER MILLER: Yeah. All right. Can -- can we ask for rationales for certain assignments.

And specifically, why do they all

represent the allocation of the residual back to the customer -- domestic customer classes?

MR. ROBIN WIENS: Anything else would be a policy decision, Dr. Miller, and we weren't -- this is cost of service study.

DR. PETER MILLER: All right. And had you -- at -- at the conclusion of the Centra Hearing, I think there was an indication in -- in closing argument that consideration would be given to full cost accounting, at least in the context of gas supply.

Have you given any thought to how such a concept might apply in the electrical cost of service?

(BRIEF PAUSE)

MR. ROBIN WIENS: There's no externalities in here specifically identified in this Cost of Service material that's been filed.

I mean, there are steps that are taken, particularly in planning and developing generation resources, to deal with issues related to mitigation, compensation and so on, related to the impacts and to the extent that those are monetized, they're included in the capital costs of generation. And -- and are thereby allocated via the Cost of Service Study.

Beyond that, I'm not aware of any explicit consideration of externalities.

DR. PETER MILLER: Thank you.

THE CHAIRPERSON: Is there any other questions of Hydro at this point in time, for the purposes of this particular Technical Hearing or Technical Conference I should say? Yes. Professor Miller?

DR. PETER MILLER: Yes, I think this is sufficiently technical. I think there was a -- a statement in there that mitigation costs and compensation costs were all assigned to generation. And I guess I'm wondering, are there no mitigation or compensation costs associated with transmission lines?

MR. ROBIN WIENS: There may be. I'm not aware of them or how they were defined. But to the extent that they have been monetized, they would be included in either the capital or operating costs associated with the -- with the transmission and distribution facilities.

DR. PETER MILLER: Thanks.

THE CHAIRPERSON: I think, Professor Miller, I'm not in any way attempting to -- your questioning in that, I'm not questioning it's validity, I just think it's best reserved when we get into the IR

Process through to the Hearing, when we extend beyond just the tutorial that we were all receiving. Thanks.

Is there any other questions on their technical briefing? Mr. Peters, do you have anything?

MR. BOB PETERS: Mr. Chairman, I think on reflection, Ms. McCaffrey I hope would be pleased with the way the afternoon went. I -- I do believe that it accomplished the purpose that we had all hoped it would, and not to say that there's not a lot of issues out there, and it's good to hear that parties are going to have them, and I suspect the Board is going to -- to see those front and centre at another forum.

But I think along with everybody else I'd like to thank Mr. Thomas, along with Mr. Wiens, Mr. Surminski, Mr. Warden and Ms. Wallace, for putting on the afternoon and -- and fielding our questions. I think it's accomplished what we had hoped it would be.

And if anybody has different views or similar views, they're free to notify the Board and it's through these processes that we can decide whether we do this again, or if we do it again in a different way, and how can we -- how can we maximize its use and its value.

So thank them again.

THE CHAIRPERSON: I want to thank, as Mr. Peters was saying, Hydro, for bringing forward this idea.

I think it was useful to have everyone together to listen to this. It may advance the understandings when we come to the Hearing, and it's probably a very good introduction into the whole process.

With respect to the Pre-Hearing Conference, we still have to arrive at the time table, and the decisions with respect to the Intervenors that have applied, and I'm sure with the fine help of Board Counsel and the rest of you, we'll arrive at a time table and a consensual basis and then we will release that and the order in due course.

So thank you very much again, for everyone, for coming. Professor Miller, you --

DR. PETER MILLER: Sorry, I had put a question about pre-asks from TREE, I -- you already have some received, and I'm -- I'm wondering what your view is on that?

THE CHAIRPERSON: Well this is just the Technical Conference, but I think during the Pre-Hearing Conference I suggested to you that if you were to prepare such a list -- just a second here.

Mr. Peters, can you give us any advice on that? I'm trying to be reasonable, given that the -- MIPUG's approach here.

MR. BOB PETERS: My off the cuff advice,

and this is where I'd hoped to have spoken to the parties further is -- is somebody said it perhaps aptly, that these pre-ask questions are in the guise of first round Information Requests, and if that's what they are, then why don't we have two (2) rounds of Information Requests?

I think our schedule's going to be sufficiently long that we can accommodate it, and this will hopefully eliminate the need for Manitoba Hydro to rush to get this information together, if it's -- if it's the precursor for a lot of people preparing their materials, then let's make it a formal part of the process, so that Manitoba Hydro isn't under the crunch to get it done quicker.

I do think my own reaction is subject to again caucusing with My Colleagues, that -- that we probably are looking at an early May start for this Proceeding, because that seems to be the time of the least conflict. And between now and then I think we have ample opportunity to make sure we get all the information.

We've heard from people, Dr. Miller as an example, his export -- his expert is unavailable. We do know that Mr. Harper, also known as Mr. Turner, has -- has an extremely busy schedule with other regulatory proceedings.

So the time devoted to getting information in little dribs and drabs, strikes me as inefficient, and it would be better if we could come up with a time table that would allow parties to ask these important questions first, and then our second round IRs will really be for those who rely on the information from the first round, to -- to finalize them.

So I will -- I will work on the time table and -- and present it to those who have applied for Intervenor status and -- and find their comments, and see if we can reach that consensus.

But that's my -- my current advice, is that we probably would aim for the two (2) rounds of Information Requests to -- to make sure that we don't have these. Because quite frankly, everybody here has pre-ask questions they want to -- to start with. So -- so let's call it what it is.

THE CHAIRPERSON: Well said, Mr. Peters. Okay, then we'll stand down and adjourn. Thank you again.

--- Upon concluding at 3:00 p.m.

Certified Correct,

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Carol Wilkinson,