MANITOBA PUBLIC UTILITIES BOARD

RE:

MANITOBA HYDRO'S
APPLICATION FOR APPROVAL OF
ENERGY INTENSIVE INDUSTRIAL RATES

Before Board Panel:

Graham Lane - Board Chairman
Robert Mayer - Board Member
Susan Proven - Board Member

HELD AT:

Public Utilities Board
400, 330 Portage Avenue
Winnipeg, Manitoba
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Pages 887 to 1060

APPEARANCES

Bob Peters	)Board Counsel
Patti Ramage	)Manitoba Hydro
Janet Mayor	)
Byron Williams	)Coalition
John Landry	)MIPUG
Michael Anderson (np)	)MKO
Bill Gange	)RCM/TREE
Beth Tait-Milne	)

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--- Upon commencing at 9:05 a.m.

THE CHAIRPERSON: Good morning, everyone. I understand everyone in the room is pretty well aware of this, but due to the unfortunate deaths of two (2) individuals that are well-known to a lot of the people in this room, we are going to stand down from 10:30 to 1:00 this morning after we hear from MIPUG's direct evidence from their witness panel to allow people to attend their funerals, and then we will resume again at 1:00. So we begin with Mr. Williams.

You wanted to speak on one of these unfortunate occasions?

MR. BYRON WILLIAMS: Yeah. And just very quickly, Mr. Chairman, and certainly on behalf of my clients, last week, Alister Hickson, a person well-known to the MPI side of the regulatory process, passed away, and his funeral is today. And for many years, he was head of regulatory affairs at Manitoba Public Insurance and often an opponent of my clients but always in a fair, vigorous and intellectually rigorous way.

In the latter part of his career, he came over to the -- to the good side. And I'm just teasing. He provided excellent analytical support to the -- to the Canadian -- to the motorcyclists, as well as to my clients. And also, his knowledge was shared with consumer groups in British -- British Columbia.

So his sad passing at the age of fifty-four (54) is, a course -- of course, a loss to the regulatory process and an even greater loss to his family and his wife, Denise, and his daughter -- or step-daughter as well.

So on behalf of my clients, they -- they just wanted to offer their condolences to the Hickson family.

THE CHAIRPERSON: Yes, the Board joins in that as well. We had become quite accustomed to seeing Dr. Hickson from time to time as an advisor, eventually, to the motorcycles group. And he was always very well prepared and did an awful lot of background work that helped develop information that was useful to the Board as well as his clients and other clients. So thank you, Mr. Williams.

Mr. Landry, if you just want to first begin by introducing your witnesses, and then we will have Mr. Gaudreau swear them in. And the only witness that we would like to just briefly run through their credentials on would be Mr. Ostergaard, because he has not appeared before the Board before; the others have.

MR. JOHN LANDRY: Thank you, Mr. Chair.

Yes, Mr. Chair, as you are aware, as the other stakeholders are aware, we have a panel of three (3) today. Two (2) of the witnesses, the Board is familiar with.

And on your far right, the Board's far right, starting with Andrew McLaren, who is a principle at Intergroup; and to his right is Mr. Patrick Bowman, also a principle at Intergroup; and as the Chair said, on your far left, Mr. Peter Ostergaard.

For those who are not familiar with -- with Mr. Ostergaard, he is a consultant from Victoria, but formerly the ADM of Energy Mines and Petroleum Resources in British Columbia and also the former Chair of the BC Utilities Commission.

In the case of Messrs. Bowman and McLaren, their CVs, for the record, are at Exhib -- MIPUG Exhibit Number 2, Appendix C. And Mr. Ostergaard's CV is MIPUG Exhibit Number 3, Attachment A.

Now, before swearing, the approach that we would like to take, Mr. Chair, today is, as opposed to having a ques -- direct question and answer, each of the witnesses will provide a -- a summary of -- of the evidence that they have provided, along with trying to engage in some of the issues that have -- have arisen during the process here. And we'll start with Mr. Bowman in that respect.

But perhaps we could have the witnesses sworn first, please.

Mr. Gaudreau...?

MIPUG PANEL:

ANDREW MCLAREN, Sworn

PATRICK BOWMAN, Sworn

PETER OSTERGAARD, Sworn

THE CHAIRPERSON: Thank you, Mr. Gaudreau.

Mr. Landry...?

EXAMINATION-IN-CHIEF BY MR. JOHN LANDRY:

MR. JOHN LANDRY: Mr. Chair, firstly, just for the record, the IRs that were asked of Messrs. -- or Messrs. Bowman and Mr. McLaren, the answers were prepared under the direction of Mr. Bowman for people -- people's Information. And the IR is in relation to Mr. Ostergaard's evidence. Mr. Ostergaard was -- had the responsibility for preparation for those answers.

And I guess the first item of business would be are there any corrections, panel, to the evidence that was filed?

Mr. Bowman...?

MR. PATRICK BOWMAN: Yes, thank you. Good morning, Mr. Chairman, members of the panel. There is only correct, or I should say update, which is in the time since the evidence was filed, page 8 of the InterGroup evidence -- which is MIPUG Exhibit 2 -- lists the membership of MIPUG.

And I would just say since that time, Tembec Incorporated at Pine Falls is no longer a member of MIPUG. So that's -- that's just an update.

MR. JOHN LANDRY: Mr. Ostergaard...?

MR. PETER OSTERGAARD: Yes, I have one (1) minor correction in my pre-filed testimony. On page 9, again, a minor error in Footnote 1, Footnote 1 reads:

"A large industrial customer is generally considered to be a customer that takes electricity at a transmission voltage and owns its own substation to step it down, and BC transmission is 69 kV and up."

That should read, "And BC transmission is 60 kV and up."

MR. JOHN LANDRY: Sir, that's Footnote Number 9 at Exhibit MIPUG Number 3, correct?

MR. PETER OSTERGAARD: Actually, Footnote

1, according to my records.

MR. JOHN LANDRY: Oh, sorry, Foot -- Footnote 1.

MR. PETER OSTERGAARD: On page 9.

MR. JOHN LANDRY: Okay, page 9, thank you. And those, I understand, Mr. Chair, are all the corrections or updates, and so I'll hand it over to Mr. Bowman.

THE CHAIRPERSON: Very good, sir.

MR. PATRICK BOWMAN: Thank you. I will set out a few comments in regards to the evidence that is filed on behalf of MIPUG. Bef -- and -- and then we can talk about the organization for walking through the evidence today.

I would note at the outset that when we received the application and -- and the materials in regards to that, the key thing that was noted by -- by us and -- and in conjunction with the members is that under Hydro's current proposal, most of the MIPUG members are now not expecting to pay this rate for the five (5) year period that the -- for which they have their -- their plans in place.

The proposal is quite a bit different than the last proposal in that regard, where there was some uncertainty about who would -- who would be required to pay it, given the economic impact aspect of the previous one, and that the -- the proposal's more focussed in that it mostly now ends up hitting a very small number of customers, who tend to be pipelines and chemical companies who are portrayed as being price-sensitive, although I will have some comments in regards to that.

And in regards to the proposal, the -- the other thing that is noted is that, in many ways, the current proposal is more transparent than what Hydro filed before. It doesn't have the complexities that come with the economic impact test.

There's still issues, certainly, with respect to rate stability, with respect to aspects of transparency, particularly with regards to the links to firm export rates, five (5) by sixteen (16), and the relevance of that linkage to an export price, for example.

But when we received the -- the application, we spent a bit of time going through and figuring out how to deal with it and how to understand what we had before us. And -- and we found that we really needed to think about the proposal at -- at sort of three (3) levels, which is a bit unusual for a regulatory filing.

At one level, sort of the most detailed

level, Hydro sets out a number of -- of, sort of, purported facts in its -- in support of its case. We found a few of these to be not particularly compelling or didn't seem to bear out in the evidence.

We summarized these at page 4 of our -- of our evidence, but we particularly deal with them in our Appendix B. And this is in the InterGroup evidence, MIPUG Exhibit 2. And examples were that the growth that Hydro was going to charge this rate to our coming here due to low rates and -- and also the concept that all industrial load changes drive changes in the firm export market, the volume of firm export sales.

We put them in -- in Appendix because they weren't central to the matters we were dealing with in our case but -- but were still important to deal with. They're certainly central to Hydro's case, and they're -- Hydro spent a fair bit of time filing rebuttal on those points. And so we'll -- we'll spend some time to address that.

At a second level, based on that set of facts, Hydro has put forward its particular proposal, in terms of how to deal with this -- this rate, put forward to the Board. We deal with their proposal. I say the InterGroup evidence and the main part of our -- our evidence, and we address it in sort of three (3) ways.

One is looking at this proposal in relation to the concept of efficiency rates, and we summarize our -- our comments there at page 5. And we note that the rate is not really designed to achieve efficient pricing. And I'll have some more comments on that as we move through.

It's consistent, TREE made the comment it's largely symbolic. Our high-level review is -- it -- it is probably not even that, given that it's not even intended to symbolize efficiency in a sense. It's -- it's really trying to shoehorn a concept of efficiency into a rate that's really aimed at something quite a bit different.

The second aspect that arises with respect to Hydro's proposal is the evolution in -- in thinking from what we saw last spring in the type of growth that is targeted. As of last spring, Hydro had brought forward a proposal that had exemption criteria based on economic impact so that in essence, their proposal was targeting growth that was uneconomic for Manitoba, would be the basic assertion. Growth that was economic for Manitoba was allowed to grow -- was allowed to continue.

This proposal is a fair bit different in that instead it targets the pace of growth, not the -- the benefits to Manitoba. It's targeted something quite a bit different and when you start to talk about the pace of growth over the long-term, it really drags in the concept of, sort of, system planning and impacts on the system.

So we deal with that and summarize our comments on that in page 5 to 6 of the InterGroup evidence, and -- and I'll -- I'll speak more to that as we move through.

And the third major topic area is that the rate represents quite a change in the way that Hydro has its -- for its structure of industrial rates and dealing with industrial growth. And again, this -- this is sort of summarized more on page 6 of our evidence.

I'll speak a little more to this as we move through as well, but noting that the situation in Manitoba is really not all that unique in many respects, but that the solution proposed is quite unprecedented.

We also -- in the InterGroup evidence, there's also an Appendix A, which I probably won't speak to much. But it's -- it's effectively a few small details that -- in Hydro's proposal -- that in the event someone were to move forward with a -- a rate of this nature and determine that it was -- it was needing to be implemented, there are a few things in Hydro's proposal that are -- that are sort of unique items that -- that would probably merit amendment.

Now that's sort of two (2) levels of Hydro's proposal of the case, and they're -- they're -- it's not unusual to have to look at a case at those two (2) levels. What -- what are the facts, and do they support the proposal in place?

In this case, we -- it was -- there's something -- there's another level that's quite a bit unique and it has to do with the concept of the regulatory review of the proposal.

And in that regard, there's sort of two (2) aspects. One is that there -- that this proposal has been seen by the Board before, and it was -- was the subject of a number of Board directives for things that the Board wanted to see. There was quite a proscriptive set of -- of concerns that were meant to be addressed, including practice in other jurisdictions.

And -- and to deal with that, we -- we decided in the spring to start to look at how we could bring the Board solid evidence about what happens in other jurisdictions. And, of course, the Board will recall that at that time we discussed a fellow from Quebec, who gave us a briefing, and also, Mr. Ostergaard, who -- who filled us in on the BC situation and -- and had a few useful comments at that time in this regard and has since been able to fill them out more.

And the second aspect that's quite unique about this proposal that merits a comment on regulatory review is that the Board is, in essence, being asked to do something that is very unusual. It's not common in a regulatory environment for a utility to come forward with a rate that is, in effect -- I'll go to the word -- that -- that is discriminatory, and the Board being asked to effectively test whether it's unduly discriminatory. That's not the usual type of setup.

And so to help with that, we -- we make some comments in that regard, and we've been -- and Mr. Ostergaard was also able to help us to think through aspects, such as the threshold for review required by this type of proposal. He frames his comments in respect to the experience in BC, but also the regulatory considerations as to how to think about the issues before the -- the Board.

So in terms of walking through the evidence today, I -- I will start by going through the InterGroup evidence, which is Exhibit 2. And I -- I will go, sort of, through the sections -- so it may be helpful for people to have it before them -- through the evi -- the sections proper, which deal with Hydro's proposal.

Mr. Ostergaard will then go through his

piece, which reviews the situation in BC, focussed on the matters the Board had specified that it wanted reviewed, as well as his general comments on regulatory review of this type of proposal.

In respect of the detail matters, we'll finish up by Mr. McLaren and I going through our -- our Appendix B and Hydro's rebuttal to them on the -- the details of the -- sort of the facts underlying Hydro's case, and -- and I'll close up with any remaining matters in Hydro's rebuttal.

Just to start off, our evidence provides the -- a summary leading up to about page 7. At page 8, we set out a typical item in this type of evidence that's focussed a bit on the MIPUG members, their -- their types of concerns and the things they -- they asked us to look at.

It's there for people to read in general. Though when we're dealing with industrials of this type, whether we're representing them here or in other places, things become very focussed on their -- over long-term investment and thinking about the fact that once assets are put in the ground, they're very much a captive customer and are reliant on fair treatment by the utility that they're required to deal with, stability and -- as a result is key, and protections that -- that a regulatory system provides.

We also put in there a few details, though, in respect of industrial customers and the tendency, which is acknowledged by Hydro, for load growth by industrial customers to be quite lumpy. It doesn't tend to suit a small percentage change each year. It tends to be additional processes added or a new pipeline put it, and it doesn't necessarily suit well the concept of an annual percentage growth.

Our -- Section 2 of our evidence goes -- goes from about page 10 on, provides the key background that we reviewed in -- in preparing the evidence, and in particular, reviews the Board's directives that were given, the seven (7) or eight (8) items that were built into the Board's Order 11608, that the Board wanted to see reviewed, and -- and provides the context for the rest of the evidence that we had put in, in terms of -- of trying to address the things that the Board said it -- it wanted to focus on.

And Section 3, which starts at about page 14, is where we summarize Hydro's proposal. Given the exchanges that have gone on, I wouldn't intend to dwell here for a long time. There are few comments, though, that I'm -- I'm not sure have -- have been made clearly, that it's fairly important to -- for us to deal with.

One is, in -- in simple terms, we note that the rate appears to be designed to be implemented starting April 1, although there are some other comments in other places that suggest that the rate would be implemented more along the lines of July 1st, based on export prices leading up to March 30th, '09, or perhaps that the rate would change on July 1st.

And it's a matter which has a little bit of lack of clarity that we thought should probably be clarified before we know what we're -- what the Board is being asked to approve.

And -- and the comments in respect of July 1 are set out at Footnote 15 on page 14 of our evidence in respect of IR RCM/TREE, Round 1, Question 30.

In this regard, the -- the proposal is, in essence, not revenue neutral to Hydro starting April 1. These are loads that exist or that will be in place before April 1, and it will either be charged a lower rate or a hydro -- higher rate. Given that these loads are arising, and -- and have come, and are here, in that regard, over the very short term, revenue neutral wouldn't -- wouldn't seem to be a fair definition of -- of the rate impact.

We found Hydro's response -- and I'm at page 14 of our evidence now. We found Hydro's response to the question PUB/Manitoba Hydro-1C particularly interesting. This response was also put in the -- the Board's -- Board counsel's book of documents, Tab 4, where it sets out Hydro's objectives for the rate.

And when I said we organized our comments around the rate in respect -- in -- in sort of three (3) packages, these -- these four (4) objectives hel -- helped us organize into that -- that structure.

The first objective Hydro had set out was that the rate was to promote economic and more efficient price signals. We deal -- we'll deal with efficiency as we move through. The second was to deal with rate impact, short-term adverse rate impacts. And the third was to deal with the adverse impacts on long-term power supply. Each of those are aligned with the section of our evidence.

I would only note that the fourth as -- bullet here, which was to allow for economic expansion, Hydro's quote was the rate -- the objective of the rate is to achieve the above Objectives 1 to 3, while still providing scope for economic expansion, and Hydro does not want to unduly constrain economic development.

We do not spend a lot of time on this point, in part, because I don't see how the evidence is here to determine whether -- what -- what is a due constraint on economic development, whether it's duly or unduly. The -- the evidence just seems to be absent to be able to determine whether that objective is being met.

In going through the summary of Hydro's proposal, we spent a fair bit of time, starting at page 17, looking at a comparison to Hydro's previous proposal.

And as it has been mentioned a number of times, Hydro's proposal in the spring was effectively based on three (3) -- three (3) central assertions or tenants.

One is that we had lots of industry growth being attracted by low-cost rates in Manitoba, that, as a result of the gap between marginal cost, as they -- as they measure it, and imbedded rates, this puts upward rate pressure on others, and that these customers bring little economic benefit to Manitoba. That was the central premise behind the rate proposal we dealt with in the spring.

The new proposal, as I mentioned, drops the assertion of limited economic benefits to Manitoba. There's actually effectively no information on economic benefits in the proposal, with one (1) exception. The exemption appears to be in respect to government customers, which are said to be exempted from this proposal, as they bring -- as they bring benefits. So apparently, benefits is a -- remains a test for government customers.

I don't think it's a particularly material exemption, because there's no government customers in the size range Hydro's looking at either. So it's not a key item; it's just the one place where economic benefits are -- or overall social benefits remains mentioned.

The elimination of an economic benefits test is in a sense bittersweet. There was always a significant challenge thinking through how to deal with the concept of -- of an economic benefits test before a regulatory tribunal designed to set electricity rates.

And it wasn't just MIPUG. It was a number of people in the room had -- had some discomfort with the entire package that was -- was being discussed, in respect of an economics benefits test.

At the same time, the change in the proposal now effectively goes without saying, that it does not have a benefits exemption. And as a result, there's no provision to -- to deal with the fact that there could be fairly significant adverse impacts on economic development in certain cases that -- that would arise from this rate.

There's no provision in the rate, there's no provision in the proposals before this -- this Board, and there's no provision, as far as we could see, in any -- any other obvious Manitoba Hydro or other sort of legislative regimes to deal with -- with the possible adverse impacts on economic development.

There's also, in this -- in Hydro's current proposal, no level of certainty, particularly beyond your five, as to who this rate might -- might hit. And if -- there's certainly no level of certainty or transparency about what customers might have come, but may elect not to come now as a result of this rate, we really don't know what those impacts might be.

Hydro makes a statement in a few cases that existing customers have elected not to expand, or in -- or in one case that -- in at least one case a customer elected to -- to locate elsewhere. And we really know very little about these customers and what -- what impacts might have arisen in Manitoba, had they chosen differently, and whether this rate was the -- the key factor in their decision.

But in essence, putting aside the economic benefits, what the new proposal does is it very much moves to focus on, as Hydro puts it, rapid growth, not -- not economically, unadventageous growth.

And in the context of constraining rapid growth, it -- it is, in essence, a tool more aligned with planning your system over the longer term than -- than the previous proposal was.

The previous proposal was more aimed at -- at planning an economic system, not a -- not a power system, if you like. And the end result of this proposal is, in effect, a much stricter constraints on growth, give that there's no exemptions.

A big new load that would be beneficial for Manitoba in the previous proposal would have been allowed to come in embedded cost rates; in the new one they wouldn't be given embedded cost rates. And as a result there's a -- I would say a greater likelihood they wouldn't come. And if they're indeed price sensitive, I think it's highly unlikely they would come.

The third item, where I'm now up to about page 20, the third item we put is that the new rate provides greater clarity over the coming five (five) year planning horizon.

And I will say that this point has been made a number of times for most of the MIPUG members, for most of the industries in Manitoba, it is easy for them to look at their exemp -- their current expansion plans. Those plans are more robust over the next five (5) years than they are beyond five (5) years. It's easier to plan the short-term than the long-term. And they can look at the numbers and run the numbers through and determine if this rate will impact them over the coming five (5) years.

Assuming the rate is approved as it's been put forward, there are -- I will assume that all of the customers have done their math and they know where they stand in terms of what they expect to occur over the next five (5) years. Over the long-term, it's another matter.

And the last point that we put in there in regards to the -- this proposal versus the last is -- this is Item 4, and it's at page 22, and it's issues regarding the determination of a marginal cost.

By shifting the measure of marginal cost in this proposal from the previous, Hydro has gone to a number that, at the time we prepared the evidence, we said offered greater transparency. Having been through a few more rounds of IRs and listening to in the room, I'm not sure it's quite as transparent as we might have assumed at the time we wrote the evidence.

And so that may be a bit of an update. It certainly is a different approach. It does not offer the benefits of a forward-looking approach in -- in terms of an economic efficiency type of test, and it's not clear that it offers customers the degree of transparency that may be appropriate for people who have to pay the rate.

It -- it's clearly an improvement, however, on the marginal cost studies that Hydro was planning on relying on before where -- we were given a number with not much else that was behind it, that wasn't said to be confidential.

Moving on to Section 4 of the InterGroup evidence, starting at page 23, the first major topic area we deal with in reviewing Hydro's proposal is -- it is the one that Hydro put its Objective Number 1, which was efficiency and price signals. And I think it's fair to say that in comparison to rates that are designed to achieve efficiency, this rate fails any reasonable test that would be applied to those type of rates. It is -- it is, in essence, almost at odds with the concept of an efficiency price signal rate.

It doesn't affect many customers. The customers it's affecting, it is -- are said to be price-sensitive, but I would say that argument doesn't seem to bear out, in that anybody who's gonna -- seriously price-sensitive, wouldn't elect to pay a five point five (5.5) cent rate when they have three and a half (3 1/2) cent rates available in other places, if they're really price sensitive.

Almost by definition, anyone paying this rate is captive and has to pay it. If they're really price sensitive, they could move. So anybody who's really price sensitive and looking at Manitoba, is not going to elect to come here, pay a higher rate and become more efficient. They -- it won't achieve that objective. It will achieve them not coming here, if they're really price sensitive as asserted. And so in that sense it doesn't achieve any efficiency objectives.

Now what seems to be put forward by putting the concept of efficiency here is really trying to shoehorn this idea that efficiency is a good thing and we should try to design rates for efficiency into a proposal that's designed for something that's not about efficiency at all. It doesn't fit.

It's -- it's trying to turn this proposal into something that it's not. It's oriented towards a different set of objectives. And as a result, there's some danger by trying to find the way to take a proposal that's not oriented efficiency, and amend it and tweak it into something that it's -- designed to get the efficiency.

It -- this is a very appropriate debate for future proceedings and once the appropriate information is here about efficiency rates. There are customers who have said that they can benefit from certain types of structures that allow a greater pursuit of efficiency, whether that's an increased ability to see benefits from -- from DSM or particularly those who -- who have the ability to shift loads in certain ways with response to time-of-use, for example. But they require a fair bit of thinking oriented a very different way than the information that's -- that's before the Board today.

Moving on from the efficiency point, Section 5 of our evidence deals with the concept of the bulk power system planning. And as I noted going through the -- Hydro's proposal, when we were looking at the previous Hydro proposal, there wasn't a lot of need to focus on the long-term bulk power system planning in a sense, because it -- the proposal was not looking to sort of cap growth the same way. This proposal is very much aimed at managing growth and managing the load forecast over the long term and that's a fairly major change.

So we spent a fair bit of time on this topic. It obviously elicited some comments from Hydro in their rebuttal, particularly pages 3 to 4. But what became quite clear to us is that the -- the proposal, in offering the 3 percent growth for five (5) years, and only 2 percent thereafter, that 3 percent is given no matter what; the 2 percent is only if you actually use it.

So in many years, the growth in CBL will be zero because customers won't grow. And that it offers a one (1) time opportunity to advance 10 percent, but once the customers use that, they can't use it again. So there's some thought that, in many cases, customers would be looking to use that as soon as possible; that it really is a proposal aimed at -- at constraining growth more so over year six (6) forward, than it is through years one (1) to five (5), when a lot of other things are going on on Hydro's system.

So we spent some time looking at those years, years six (6) and on, and -- and what was going on in Hydro's system at that point, and -- and saw some reasons for concern, in terms of the power resource plans and the system planning information that was available to us, in terms of -- of the overall state of Hydro's system and the overall plans for being able to pursue greater levels of exports.

Starting at page 26 we review three (3) different sets of power resource plans and loads, looking at what is going on in the 2001 proposal, which is the status update filing, in the situation of 2005, which was made available in this hearing, and the situation of the 2008 Power Resource Plan. We haven't seen the 2009 Power Resource Plan. I understand that it may be being filed shortly.

And we track, going through that; what's happening on Hydro's system, looking out to the -- the time of the next major plant about -- in about 2020; and what are the levels of surplus and shortfalls that arise then; and also, what's happening with industrial load at -- at that time. Industrial load is the General Serve Large greater than 100 kV.

The first thing that I'm not sure most people are -- appreciate looking through this, is in about 2020/2021, that -- that period, Hydro's Resource Plan shows a fairly major retirement of the thermal plants. Brandon Coal is scheduled to be taken out of the service at that time, and Selkirk Gas is, similarly, about that same time, is -- is scheduled to be taken out of service. Whether that actually occurs, I presume, will be the subject of life extension discussions as -- as one gets closer to that, but for planning purposes, those are the numbers that people use.

As a result, there is a -- fairly large shortfalls that start to show up as soon as you start retiring those plans, because up to that time you're relying on those plants being able to supply loads in drought. And -- and the power resource plans are always based on the dependable year, the drought year, making sure you can supply your load. Consequently, you tend to see the next plant almost always required in about that time period, between 19 -- 2020/2021.

Wuskwatim has been talked about in terms of being now needed for a domestic load. Wuskwatim's quite a small plant. It's less than 5 percent of the domestic load; its -- its fairly swings can effect Wuskwatim. And -- but outside of that, the -- the real shortfalls, in a power resource planning context, arise about the time of the -- the retirement of the thermal plants.

In the 2001 Power Resource Plan it was Wuskwatim that was thought to be needed at that time, 2019 -- or '20/'21, about that time, in order to deal with the shortfalls that will arise due to the retirements for thermal. At that time, people were expecting industrial loads in that same year, '20/'21, to be about 6 terawatt hours. And based on the forecast that were put in place, we're -- we're basically on track for -- to-date, for that forecast. I mean, up until -- actual loads up to 2008.

By the time you move to 2005, Wuskwatim was still expected to be available for export until '20/'21. Industrial loads to '20/'21 had now been rachetted down from 6 to about 5 1/2 terawatt hours; not a major swing, but -- but dropped, nonetheless. But if you actually look at what was forecasted within the industrial load forecast, it was a -- quite a dramatic reduction in the expected growth in the class; less -- much less than 1 percent, you know, in the range of half a percent, or even lower; point six (.6) in -- over sixteen (16) years, point two (.2) over a longer period.

By the time you get to 2008 things had changed a fair bit. And this is starting at page 27.

We are now talking about a system that still had shortfalls arising in that same period, '20/'21. It still had thermal retirements, although they were being delayed a year to line up with the Conawapa in-service. And it -- it still had some level of load growth to their -- except by this point, we're saying industrials by '20/'21 will be up to about seven (7) -- a little over 7 terawatt hours. So we went from six (6) in 2001 to about seven (7) in the later forecasts, a swing of about 1 terawatt hour from the earlier set of forecasts.

Looking to that time frame, there are some other major changes going on in Hydro's power resourcing planning. At this point, Hydro is now looking at bringing on upwards of 8 terawatt hours of new generation about that time frame between Conawapa Keeyask, as well as some other resources between now and there.

It is looking at increasing its overall level of exports by about 5 terawatt hours, related to already announced firm power commitments.

And it's looking at a total growth industry in the range of about 2 terawatt hours -- about one (1) of which is sort of new compared to earlier forecasts.

Of that growth, half of it is -- or so in the industrial sector is from pipelines that are not what you would call "price sensitive." There's obviously some natural growth going on.

But the sort of rapid growth being targeted is really quite small in the mix of the overall resource planning things that are happening in Hydro's forecast, maybe one-tenth (1/10th) of the story in the overall planning forecast.

So the thought of -- of needing to do something with this industrial load at a time when -- when those sort of big numbers are swinging as you look further out, it's a very small factor.

I'll have some comments about the firm power sales and Hydro's rebuttal on that as we move forward. But we were also persuaded that this required some attention, because in essence, Hydro's proposal before the Board is very much focussed on, I'll say, a --

a preference for protecting exports rather than using loads domestically and for being able to maintain those sales going over the tie-lines that may be full and may not, and doing so as a -- as a -- as a high priority objective for the corporation.

It's the Board's Order in -- in Board Order 90/'08, 116/'08, expressed some level of concern with that focus. The quotes are set out, the bottom of page 28 to the top of 29.

The Board expressed concern -- not to be confused with opposition -- but concern over the magnitude of spending in the pursuit of the -- of the exports in that way. They expressed concern about the risks that may come with that and have sought to have a terms of reference provided for regulatory review of the overall plans to make sure that they're -- they're -- the impacts on rates is warranted, is the word the Board used.

In the context of that concern and uncertainty, it's in -- in our reading of it, it's a bit of an odd time to be making a decision in this type of hearing, that we actually do want to be constraining industrial loads in order to effectively prioritize exports, because they are two (2) pieces of the puzzle that one puts together when looking at advancing plans, whether that's bringing on wind, whether that's bringing on new loads.

There was some discussion back in the Clean Environment Commission hearings when Wuskwatim was being brought on about tie-line constraints and how domestic load growth actually helps you bring on new plants. It can actually help getting new developments in place, because it relieves load on your tie-lines effectively. It's the same comments that were made earlier in this hearing.

And so they're -- they're parts of the same puzzle, if you like. And given the certain level of uncertainty and concern that was expressed by the Board in respect of how all those pieces fit together, this puzzle piece being in play or being locked down seems somewhat out of step or perhaps premature before someone is moving on to sort of resolve exactly how that -- that process unfolding.

And Hydro effectively acknowledges a need for that type of review. They seem to target it for 2011 in their response of their review and variance.

Now, the rebuttal evidence, in respect of the overall load balance and long-term load balance notes some new comments in regards to the committed sales and the term sheets that have been signed, that these new loads bring with them an opportunity for new imports, a commitment to new imports in -- in drought years. Although the comment is a bit less focussed than that.

It -- but it effectively asserts that -- that the new contracts bring opportunity for imports in drought years. We -- we do note the existing firm contracts when the -- at the time the existing firm contracts expire, about 3 terawatt hours or a little more of export sales go away, and about -- but about 1.1 terawatt hours of import sales go away. So I'm presuming that's the type of offset that people are talking about.

Given that there's the comment that these new sales bring with them greater import guarantees, I would assume that the relationship is somewhat larger towards the opportunity to import during drought years than that, but we have no more evidence than -- than the comment.

Effectively, I would suggest that that requires some additional attention, that what is putting forward appears to assert that the law -- the new contracts being entered into are -- are not quite the same character of firm sale as the existing -- as the one's they're replacing or -- or the current nature; that there's the idea that one (1) can import in drought years in order to off-set one's ex -- one's export in drought years, effectively means they're not the same character of firmness that would exist if you had to supply them all the time.

And -- and concepts like import guarantees or any -- any terms in a contract of that nature are not free. They come with overall costs to them; commitments to the other party to guarantee that they'll make energy available in a -- in a drought year.

And it would be -- it may be indecipherable, but it would raise questions about whether the firm sale price that is being reported, in essence, is affected by the extent to which it's really firm or which it's not -- doesn't need to be supplied in the import -- in import years. In any -- in any event, exchange doesn't really change anything in the overall -- in the overall assessment we did of the long-term picture; that we're still talking about swinging a heck of a lot more export sales and plants than anything we're doing in the industrial load side.

The final section of our -- our evidence proper, Section 6, it starts at page 31. And this is where we really start to deal with the concept of how one deals with industrial rates and the rate proposal.

The -- we note there in the first paragraph, line 3, that the approach Hydro has put forward is -- is unprecedented in Canada or anywhere else that we could determine, anywhere that has a regulated rate jurisdiction.

In essence, by targeting a small number of loads and linking them to firm export prices, the effect is that you're charging some subset of your load at market prices, or market principles mixed into an embedded cost system; that some group of customers will be paying whatever the market will bear as opposed to any linkage to Hydro's costs.

We note there that we weren't sure what Hydro was saying in regards to what this will do to their overall load development. There are certainly places where Hydro indicates load growth with be lower as a result of this proposal than it would have been. An example, there we put is the response to MIPUG/Manitoba Hydro-1, Round 1, Question 1E.

But at the same time we note comments that were made in the September 11th workshop, and since -- that some energy intensive loads like -- in this case, a smelter, it was quite large, would still come at the higher rates, and that it wouldn't be prohibitive to -- to their ability to come to Manitoba. And we found that a bit contradictory or perhaps confusing.

Hydro tried to deal with in the rebuttal at page 9. We didn't -- I can't say our confusion is -- is alleviated. The -- the aluminum smelter that they say would have come, or I assume it's an aluminum smelter, they say would have come, instead went to Quebec. There's no evidence in why it made its decision. There's an assertion that Hydro's rate was below its -- its absolute threshold, but the extent to which rate may have been a consideration is not clear, and we have no idea whether that was, in the end, a good thing for Manitoba or not.

Looking at this -- a specific set of regulatory principles that this rate challenges, starting at page 32. Customers who'll be exposed to this rate at a high level, first and foremost, will have a rate set based on them, in essence, having to bid against export markets for the power. If the price goes up in export markets, they're going to have to see their rate go up as well, or -- or be willing to forego the power.

Their rates will no longer have any linkage to Hydro's costs, to the extent to which Hydro is efficient or not efficient, and they will have very little impact from any changes in Hydro's overall cost structure. That is, to say the least, very unusual in an embedded cost jurisdiction, or in a regulated jurisdiction, at that; all power price based on incremental values of power rather than the average values, which is the concept of mixing market into an embedded system.

The way that a market system works is that the market clearing price, the amount that someone's willing to pay, is in regards to their last unit of power, in regards to their -- the extra increment that they need.

So the fact that Minnesota is willing to pay a certain price to import power, it's comparing Manitoba Hydro against Minnesota's highest cost resource.

It doesn't mean that that's the price Minnesota's going to charge its customers, because it charges its customers an average price. It's a regulated jurisdiction, similar to Manitoba.

And so in that regard, the benchmark is -- is very different in that customers in Manitoba will actually pay a market clearing type of price on a -- for -- for firm power, whereas in -- in Minnesota, customers who are served there will receive an average of all of the Minnesota resources combined.

We note that where there are regulated jurisdictions that elect to take certain rates out of regulation, the rates are set by government, not by a linkage necessarily to export powers at all. The rates may be higher or lower than regulated.

There are a few examples. Iron Ore Company of Canada served in Labrador has its rates not regulated by the Board. There's the comments in regards to Quebec having its rate regulated -- not regulated by the Regie when you get above a certain limit.

It also means that these customers will, in essence, not share in the overall benefits of Hydro's ongoing system developments and that, in fact, they may be -- may be harmed by them if certain aspects of Hydro's developments are designed to bri -- increase its ability to capture better firm export prices and that the rate pressures, in many cases, will be in opposite directions than what other customers see.

If export prices drop off, these customers would see a benefit, while other customers, presumably, would see some level of -- of increase, and whether that's due to exch -- Canadian/US dollar exchange rates or -- or other factors.

So in -- in the overall context of, sort of, the regulatory treatment, people paying this rate will see a very different outcome than -- than any other customers in Manitoba.

At page 33 we go on to summarize that in the context of a regulated rate jurisdiction, there are a set of reasons that one would consider this rate discriminatory, and indeed in our view, unduly discriminatory.

It targets no more than a few loads. Loads that have the exact same characteristics on Hydro's system will pay different rates at different times, or at the same time.

It is an aspect of -- of personal discrimination to that, not just sort of a class treatment or a different pri -- set of principles. It's actually a different treatment of customers who have effectively the same use of power.

That the rate is not linked to anything going on in Hydro's capital system. And I'll make some comments in regards to the BC tariff supplement Number 6 in that regard in a moment.

It hasn't -- there's no threats to Hydro's reliability or to its system, no emergency conditions we're trying to deal with.

And that there -- there's -- and as I said, there's no linkage between these customers' charges and the -- the costs that Hydro is incurring.

And we also, at the top of page 34, go on to say that, in effect, this proposal is inconsistent with what we would understand to be the policy, both federal and provincial, in respect of exports, which is that power to be exported needs to be surplussed to domestic needs. Those are framed a little bit differently, depending if you talk to the federal or the provincial set up.

But that they're -- the practical effect of this proposal is to redefine the surplus by effectively having domestic customers bid against exports. In the event exports are -- rates will go higher than customers here are able or willing to pay, then the power becomes surplus.

We also note that there is regulatory precedence for dealing with the situation of large customers, and it will be the last point that I -- that I deal with in -- in my summary of our -- our -- the main body of our evidence.

At Section 6.2, starting page 34, we set out that in our view, Hydro has incorrectly assessed and measured the problem that they're asserting.

That due to a number of factors that do not bear out -- as we'll deal with when we talk about the appendices -- the Manitoba load growth for industries is exactly as per the long-term forecast that was in place almost ten (10) years ago.

That the fact that there is a small number of loads that are growing or coming to Manitoba is not at all unique in regulated rate jurisdictions. Quebec recently had a 1.8 terawatt hour load, I believe it is, hook up to their system under -- under the provisions of the rate structure that's there, and BC's had pipelines expand in -- at least in the range of what -- Manitoba's seen some pipeline expansions.

Our load growth, if anything, if you look at the long-term forecasts, the biggest differences in Manitoba's long-term load forecast -- and indeed between Manitoba and other provinces -- is the extent to which we are not seeing some of the same slowdowns other people are. In -- in BC, there's been huge drop-offs due to the changes in the forestry industry, and Hydro Quebec cites it even more.

If you go to the Board counsel's book of documents, I believe it's Tab 7 that does a comparison between the two (2) load forecasts, and you look ten (10) years out, what changed between the '05/'06 and the '06/'07 load forecast? It's the primary metals, by 800 gigawatt hours.

In the '05/'06, it presumably had been dropping off and -- and at least one of those customers coming close to closing or -- or at least significantly scaling back. By the time you get to '06/'07, it shows growth in that -- that sector. It's not the -- these same price-sensitive loads that we've been talking about.

So the -- the idea that we're not seeing the same type of closures or -- or reductions to offset growth in other categories, that may be a -- quite a unique factor in Manitoba.

The other item that we'll deal with in the appendices in regard -- is in regards to load growth by any class raises the rates to all the other classes. That's -- if you accept the marginal cost being asserted, it's a -- it's a balanced impact when you finally move to the cost-of-service type of impacts.

And there's a few other points there that we can go through. The -- I'll -- we'll deal with these more in the appendices that -- but in respect to, you know, a lot of the load growth we're seeing, it's from people like pipelines who have no option but to be here that they're -- I will deal with the matter of the tie-lines and the generation constraints in -- as we move to the appendices.

And of course, there's this outstanding matter in regards to the asserted gap. Hydro effectively asserts that action is required -- unprecedented action in Manitoba is required -- because of the gap between incremental costs for serving new loads compared to the revenue that arises.

Now, we put it in exhibit in the 2008 GRA that showed that that gap in Manitoba, if anything, is lower than most other jurisdictions we're talking about. It's about two (2) cents here and about four (4) cents in BC, for example. And that exhibit -- this was Exhibit MIPUG-10, and it was in Tab 20 of the book of documents -- that it is not at all a unique situation in Manitoba. I believe the Board even commented on that in its order.

And, of course, the -- the key item of concern is that -- is that the Hydro utility may be further ahead in certain situations -- in many situations -- dollar-wise, exporting power. It doesn't mean necessarily that the -- that Manitoba's further ahead, which would be the public interest concern.

The -- and even outside of that, even if you look at utility planning, there's a lot of reasons to think that a domestic industrial customer is preferable to an export market, even outside of the fact that it allows you to value add to your product rather than sell it as raw into other markets, where they use it to value add.

The first reason is that domestic industrial customers are captive. They are a very reliable market. Hydro doesn't typically have industrial customers closing once they've built a plant here. And it allows you to plan your sus -- your system on the basis of that load.

And, of course, second, that the loads can be made without new investment in cross-border transmission, which is challenging to put in place. There is some cross-border transmission in Hydro's plans. But you don't need those same tie-lines in the event that you have domestic load.

And it can -- and, as a result, it can quite reduce the risks of trying to get on with developing wind or new Northern generation. It gives you the reliable customer to -- to make sure that that power can be -- can be used.

Now, my final comment in -- before handing it off to Mr. Ostergaard are in regards to the last bit of -- of our evidence, Section 6.3, starting at page 36. And it's just to follow up on this point that I made about the precedent from other jurisdictions.

The situation Hydro's dealing with is not unique. It is -- in some -- in some of the assertions that Hydro makes, such as the gap between marginal costs, it's actually smaller here than in other places.

And as a result, there is a lot of benefit to be gained from looking at how other places have dealt with this type of problem. Two (2) that have been routinely cited are Quebec and BC. And we -- we put a small bullet there. Mr. Ostergaard will tell you more about the BC situation.

And Hydro comments on this in its rebuttal. In its rebuttal, Hydro effectively says that we clearly accept discrimination because we support these other type of approaches, and that it's just a question of degree.

That's not correct. In each of the cases you're dealing with Quebec or BC, you are not dealing with discrimination. They have dealt with the issue without having to put in place a discriminatory rate regime. In each case, it's for different reasons, though. It's at the rebuttal at page 11 where they effectively say that the InterGroup evidence approves of discrimination.

In Quebec you have a maximum obligation to serve that comes out of policies made by the Government of Quebec. Discrimination and the question of undue discrimination is a regulatory concept that arises and is tested within the regulatory arena, if you like. The regulatory arena is defined by the laws and policies of the jurisdiction. In Quebec the regulatory arena is defined not to include those customers. They're outside the jurisdiction; they're outside the arena.

It's just like you can't intelligently have a debate as to whether uniform rates is a discriminatory practice or not. It's the law. It's part of this -- the -- the framework that we all have to deal with here. And so it doesn't merit -- it doesn't lend itself to a test in regards to whether it's discriminatory or not.

BC is not discriminatory for another -- for a different reason. In BC's case you're dealing with large industrial customers. You have, effectively, a system extension type of approach. The system extension type of approach -- and it's called tariff supplement Number 6 -- is approved by the BCUC. And Mr. Ostergaard will go into more detail about this.

It is within the regulatory arena, and it is set up so that all customers pay contributions when they connect, as needed, under the same set of principles. And those principles are that if a customer is connecting to the utility system that is adequate to supply the loads that are there, and as a result of that customer connecting, new assets are required to be put in place to be able to supply that level of capacity -- new assets are required to put in place to deliver reliable power -- that customer pays the increment for those --

those assets, except where they're offset by the revenues of that customer in the future.

In the case of a small load, like a residential customer, you talk about the service drop. Beyond that, you can't reasonably expect that the transmission line upgrades that are needed are as a result of that residential customer. You just can't look that far into the system; you can't link it to them.

You go to a large industrial customer, and you would look different. You would say, I can think of that in -- large industrial customer driving investment in transmission or upgrading a line into wherever, into Selkirk or wherever you want to pick.

If a new customer was to locate there, and as a result, there were sub -- substation or -- or system improvements that benefit all customers, but are very much being driven by that one load, that customer could be expected to bear some of the costs of that, depending on the overall revenues they're going to pay.

What BC's system does is it defines one (1) additional threshold at 150 MVA. It says, When you get to that size, it may not only be a wires-based solution that's needed to hook up that customer. A customer of that size may actually require you to think a bit about your generation on the system, where you have things like combustion turbines, how you deal with voltage stability in the area, how you deal with reliability and backup and those type of things.

And so you may have to start to think about generation assets, like combustion turbines or other things that you need for regional considerations that are being driven by that customer.

And in the event that that customer's rates over time are not going to be enough to offset that, they may have to pay a contribution towards those assets that are required -- not that could be required but were not really paying for. No, if you really got to build them, they can -- they can be expected to share in a -- a piece of that as offset by the revenues they'll pay over time.

So it's -- it's not discriminatory, in that it's applying the same set of principles to the loads. It's just that it -- in order to implement it at different sizes of loads, you have to look to different implementation mechanisms. You need to look deeper into the system.

I can go through a bit later about the one case that -- where people have looked at the generation there.

The important thing that neither BC nor

Quebec bases its rate structure on effectively and unlimited obligation to serve major load increments with -- without having them bear, or be considered to bear, some -- some portion of the -- of the capacity-related capital costs that they drive.

And second, each jurisdiction outside of -- of the one-time payments that are needed, as time goes on, customers who are under the regulatory rate system pay the same regulatory rates calculated on the same basis as every other customer in the system. There's no "us and them," if you like.

And any charges that are paid on the capital side are linked to actual capital investment required to be made by the utility, in terms of transmission or in terms of generation; and that separately, any -- any rates designed to deal with efficiency are a separate consideration and -- and are developed or dealt with on their own, outside of the -- the question of hooking up a new customer.

Now, that's -- that's the end of our -- our, sort of, section of evidence proper. I'll have some comments when we get to the appendices. But at this point, Mr. Ostergaard would -- would go through his evidence in regards to the items we -- I set out.

MR. PETER OSTERGAARD: Thank you, Mr.

Bowman. I believe my remarks will take me to about 10:30, but no later than that.

Mr. Chairman, Board members, I do appreciate the opportunity to appear before you to provide information on the situation in BC. Over the last twenty-five (25) years or so, BC has been through the same issues you're dealing with in this application. Your order coming out of the most recent application noted a need to review relevant experience in other jurisdictions.

In my report, which was submitted as MIPUG-3 evidence, I feel I can help the Board with a full understanding of the way BC's treatment of the issues you are facing can provide you with options that, in the long run, could work for Manitoba, particularly the -- in these uncertain economic times.

Section 2 of my report responds to the specific issues you identified in Section 16.7 of your order, and I'll touch upon these in -- in these opening remarks.

The role of a single Crown utility in BC is consistent with other provinces, like Manitoba, where Hydro generation dominates. Even in the US, with it's preference for investor-owned utilities, the two (2) main publicly owned utilities -- Bonneville Power and

Tennessee Valley Administration -- were created in the '30s to develop hydroelectric resources.

I think there's two (2) reasons for this: the natural monopoly and essential service nature of electricity and the important role large projects play in job creation and investment.

Along with Quebec, BC and Manitoba vie for the title of having the lowest electricity rates in Canada. Both the Manitoba and BC governments look to their Crown utilities to provide revenues to government through sources like water rentals, dividend payments, grants in lieu of taxes, and fees for debt guarantees.

Both Crown public utilities are regulated by public agencies, the BC Utilities Commission and the Manitoba Public Utilities Board.

In BC, the government has not hesitated to use energy policies which are sometimes enshrined in legislation. And enabling legislation also provides the government of BC and the Minister with the ability to provide transparent directives to both BC Hydro and the BCUC. In addition, exemption orders articulate and sometimes limit the BCUC's powers to regulate BC Hydro. In the words of a former BCUC chair, quote, "Uneasy is the head of he who regulates a Crown."

From my limited experience, an

understanding of your regulatory framework, legislation is the main way that Manitoba sets out the matters over which you have jurisdiction, but there are differences between the two (2).

BC Governments have issued four (4) energy plans since 1990, two (2) of them in the last six (6) years. Even though electricity meets less than a quarter of BC's energy needs, all these plans have a heavy emphasis on electricity.

They have also been -- there have also been sucse -- several government-initiated BCUC inquiries on -- and task force reports. Successive BC governments are very active in establishing electricity policy and expect BC Hydro and the BCUC to implement electricity policy.

It seems to me, from my limited exposure to Manitoba's situation, your provincial government is leaving Manitoba Hydro and the PUB with the very difficult job of making important policy decisions.

Another difference is export policy. In BC exports are made only after ensuring domestic demand requirements can be met. So domestic needs drive the export policy, not the other way around. And while past BC governments have toyed with the idea, there is no pre-building of BC Hydro projects for export.

Another big difference is the current domestic supply and domestic retry -- requirement situation and the way BC Hydro will close the gap. The opening paragraphs of the electricity section of the 2007 energy plan read, in part, quote:

"BC has been blessed with an abundant supply of clean, affordable, and renewable electricity. But today, as BC population has grown, so too has their demand for electricity. We are now dependent on other jurisdictions up to 10 percent of our supply. BC Hydro estimates demand for electricity will grow by up to 45 percent over the next 20 years. We must address this ever-increasing demand to maintain our secure supply of electricity and the competitive advantage in electricity rates."

End of quote. So the number 1 policy under electricity is, quote:

"Ensure self-sufficiency to meet electricity needs by 2016."

Close quote. And the number-one energy efficiency policy is, quote:

"Set an ambitious conservation target to acquire 50 percent of BC Hydro's incremental resource needs through conservation by 2020."

Close quote. Nowhere in the energy policy is there any suggestion of singling out new customers or existing classes of customers as a way to dampen domestic demand.

And the final relevant difference is BC's continuing reliance on independent power producers to meet most of BC Hydro's supply side resource needs. BC Hydro will continue to invest in its heritage assets and work towards what could be a cabinet decision in future on the 900 megawatt Site C project on the Peace River.

So how did BC get to this policy and regulatory framework? Attachment B to my report sets out BC Hydro's history and financial structure. For now, it's enough to note that BC Hydro functioned as a large construction company through the '60s and '70s, with thousands of staff and contractors building plants and transmission lines.

Its achievements were remarkable, building three-quarters (3/4s) of today's capacity, inclement -- implementing the Columbia River Treaty, rural electrification, rate reductions, and service improvements.

With the arrival of Lumpy/Peace River generation in the early '70s, short-term surpluses recurred frequently, culminating with the fact that Revelstoke was entirely surplussed to provincial needs, but it was finished in the mid-'80s.

Researchers, including Dr. Mark Jaccard, concluded that most of this Revelstoke surplus was exported on spot markets at average prices of two point four (2.4) cents per kilowatt hour, while the levelized cost from the dam, for which BC Hydro domestic ratepayers were responsible, was four point two (4.2) cents.

Also around that time, the Site C project application was referred to the BCUC for a report. The provincial cabinet accepted the BCUC's recommendation that it be delayed until there was better evidence it was needed.

So by the early '90s, BC Hydro had been transformed away from its former role as a designer and builder of projects. Instead, new resources were being acquired in a way similar to today's, namely from independent power producers, upgrading existing generation, and power smart, but at a slower rate, as the Revelstoke surplus was being absorbed.

Powerex had been created as well. One (1) of its early roles was to facilitate exports, as long as the electricity came from private generation built for the export market and sales were for a limited term, after which the generation would be repatriated for domestic use.

While there were several responses to Powerex's requests for expressions of interest, no private generation was built for export. I mention this to underscore the public sensitivities that continue today in British Columbia about tying exports to projects, particularly when Powerex is owed over $200 million for keeping the lights on in California in 2001, and at the same time, being sued by those owing the money for alleged market manipulation.

So today Powerex focusses on near to mid-term trading positions, backing forward deals with the supply capability of the BC Hydro dams and reservoirs, the province's downstream benefits, and other supply contracts. Powerex earns over $50 million per year just by using the transmission and reservoir storage capacity to import electricity during low price times and export it when prices are higher.

Next time you're in Vancouver, considering -- asking BC Hydro or Powerex to visit the Powerex trading floor to get a better appreciation of the size and complexity of their gas and electricity trading activities. Powerex's top traders, in some years, are the highest paid employees in BC Hydro and its subsidiaries.

Attachment C of my report provides a summary of the use of a trade income deferral account, and the $200 million annual cap on trade income that offsets the revenue requirements. Policy Number 2 of the 2002 Energy Plan stated that all BC Hydro ratepayers will continue to benefit from electricity trade. And this was affirmed in the 2007 plan.

Domestic ratepayers pay for the system that enables much of the export revenues, so they are the ones that should benefit. The province decided that any net trade revenues above $200 a year go to the government. And if Powerex was ever going to lose money, the ratepayer is protected and the loss would come out of the dividend paid to the province.

Given that trade income average is around $160 to $180 million a year, rates are about 5 to 6 percent lower than they'd be without trade income. I'd like to spend a couple of minutes tracing the way electricity policy has evolved, leading to the creation of the Step Rate Structure, first for industrials, and very recently for residential customers.

In 1980 the province released its first energy policy called An Energy Secure British Columbia. It announced the creation of the BCUC and put BC Hyrdo under its jurisdiction.

To directions for the '90s appeared in 1990 with two (2) priorities, efficient energy and clean energy, and two (2) left over from the previous decade, secure energy and energy for the economy. Two (2) investigations in the mid-90s looked at reforming the BC electricity market to make it more competitive. The first was a BCUC review. It found the driving forces for reform didn't exist in BC. The second, a task for headed by Mark Jaccard, was unable to agree on any components of market reform.

In August 2001, the newly elected government commissioned a task force on energy policy to provide recommendations. The most controversial was to move to market pricing for electricity and ensure strong price signals were sent to consumers. The market pricing recommendation was explicitly rejected, and the price signal, one (1) was partially adopted in the 2002 Energy Plan with the announcement of the step rate policy for industrial consumers.

A revenue neutral two (2) step electricity rate charges less for the first block of electricity consumed and more for the second block, relative to what was a prevailing flat rate. At the higher second block the consumer has a greater incentive to cut back on electricity use, or to invest in cost effective energy efficiency or self-generation for that portion of consumption -- have the existing consumption level, the total cost to the consumer, and the total revenue to the Utility are unchanged.

Attachment C in Section 6 of my report provides details on the subsequent BCUC heritage contract and step rate inquiry and report; its acceptance by the government; the BCUC negotiated settlement process on details and procedures; the fifty-four (54) page customer baseline load determination guidelines, the CBL tariff practices; the first two (2) annual reports on stepped rates; and the upcoming review, so BCUC can send a stepped rate evaluation report to the government in late 2009.

The 2007 energy plan also requires BC utilities to explore new rate structures and encourage energy efficiency and conservation. BC Hydro responded with a residential inclining block rate application, and a two (2) step residential rate was introduced this past October.

And as Mr. Bowman mentioned, as for new

industrial customers, tariff supplement Number 6 was approved by the BCUC in 1991. It was the product of several years of on-again, off-again discussions among BC Hydro, its industrial customers, and other customer groups to develop both a standard form electricity supply agreement and a standard form facilities agreement.

A BCUC sponsored negotiated settlement process led to agreement on both. As the BCUC wrote in its 191 -- 1991 decision:

"Through the dedicated efforts and goodwill of representatives of BC Hydro, the industrial users, and commission staff, compromises were reached on contentious issues. This led to the preparation of two (2) important agreements in a form acceptable to all of the parties involved."

The decision also quoted BC Hydro's counsel as adding, quote:

"I firmly believe that this process has produced a product that is far superior to that which could have been achieved in a traditional adversarial hearing, while simultaneously saving the commissioners and others the time and expense of such a hearing."

Section 5 of my report provides examples of tariff supplement Number 6. That tariff sets out the manner in which the costs of connecting a new industrial customer are to be shared between the new customer and BC Hydro's existing customers.

And as Mr. Bowman mentioned, it also has a 150 megavolt-ampere threshold to reflect the point at which new customers should be expected to pay the full costs of new assets, including generation and high-voltage transmission that would be needed to be added on behalf of the new industrial customer.

Perhaps the most contentious policy arising from the 2007 energy plan is the one dealing with self-sufficiency. The province wants to insure a reliable, made in BC supply. And by 19 -- or sorry, 2016, BC Hydro is to have enough BC-generated power at all times to meet its domestic customers' needs.

On top of this, no later than 2026, BC Hydro will acquire a further 3,000 gigawatt hours of an energy under critical water for insurance. This self-sufficiency plus insurance policy is shrine -- is enshrined in Special Direction Number 10 to the BCUC.

What this means is that in all years,

starting in 2016, BC Hydro will have a surplus, which will need to be exported or perhaps sold domestically at a discount, as has happened in the past.

There have been no moves to set a higher rate to new domestic loads benchmarked on the price of exports and expanding domestic load arising from new and existing customers is not penalized for any negative impact that new loads may have on export revenues.

It's difficult to know the eventual impact of self-sufficiency on rates or BC Hydro's profitability and the province's economic development. There are concerns that in some years, BC Hydro will be spilling water from its reservoirs in the spring freshet because its intake or pay contracts with IPPs.

Conversely, supporters of self-sufficiency note the positive economic impacts through IPP-related jobs and investment.

So in BC the gap between heritage embedded costs electricity and the marginal cost of new supply is not a reason to impose marginal cost-based rates targeted at new or expanding loads for any particular customer or customer class.

As for electricity trade, exports are made only after ensuring BC Hydro domestic customer needs are met, which helps explain why Powerex focuses on near and mid-term sales. Powerex buys gas and electricity from outside BC to support BC Hydro's domestic needs and to meet its own trade commitments.

A time-of-use rate option was developed as part of the stepped rate in response to a reference in the 2002 energy plan to prepare one. To date, no industrial customers have chosen this option. But under this year's Utilities Commission Amendment Act, by the end of 2012, BC Hydro is to install smart meters for residential customers, opening the door to residential time-of-use rates.

So I view this application as asking the PUB to make electricity policy in the public interest, not just in the interest of ratepayers. Care needs to be exercised in trying to avoid choosing winners and losers and singling out new or existing customers for special treatment.

If Manitoba is interested in managing efficiency within an embedded cost structure, then consider looking at stepped rates. It won't be quick or easy. It took over three (3) years of concerted effort and several steps in BC and a report card on how it's working must be filed with the government by the end of 2009. But the application before you takes you down a different path, as you are being asked decide what -- who should be detached from embedded cost rates, rather than being asked to find a way to send price signals to all users.

With respect to new loads, consider looking at standard form facilities agreements similar to Tariff Supplement Number 6, which is meant to address specific concerns regarding costs to connect new industries. I say similar to Tariff Supplement Number 6 because it is far from perfect, despite taking several years of negotiations before it was approved by the BCUC back in 1991.

But again, the application before you takes you down a different and narrow path, one (1) where you are being asked to treat new industries interested in locating and investing in Manitoba in a completely different way than the industries that are already here.

Thanks again for the opportunity to participate in this proceeding. I hope the policies, principles, and perspectives, from BC's experiences will help the Board and the participants engage in a more informed discussion of the issues before you.

THE CHAIRPERSON: Thank you, gentlemen. We will stand down now and we will come back together again at one o'clock.

(MIPUG PANEL RETIRES)

--- Upon recessing at 10:30 a.m.
--- Upon resuming at 1:05 p.m.

THE CHAIRPERSON: Okay, folks. Ms. Ramage, you have got another exhibit, Number 19, here?

MS. PATTI RAMAGE: Yes, in reviewing Manitoba Hydro's records, the undertakings aren't always marked as undertakings. It's that old, We've got to learn to use that word if we want it. But this was an undertaking that Mr. Surminski gave to Mr. Peters regarding the Power Resource Plan.

Now we recognize that, having handed it out now, we might not be a -- Mr. Peters may not be able to review it in enough detail to ask anything -- or all of his questions. But subject to that, this panel still is available now to answer any questions on other undertakings or this one if people are able to process the information.

THE CHAIRPERSON: Mr. Peters...?

MANITOBA HYDRO PANEL:

VINCE WARDEN, Resumed

ROBIN WIENS, Resumed

MICHAEL DUDAR, Resumed
HAROLD SURMINSKI, Resumed
DAVID CORMIE, Resumed

RE-CROSS-EXAMINATION BY MR. BOB PETERS:

MR. BOB PETERS: Yes, thank you. I was going to say to Ms. Ramage that just because I have more time doesn't mean the questions will get more intelligent but...

Mr. Surminiski, you worked overtime to prepare Manitoba Hydro Exhibit 19, sir, in an answer to a question that I had of you previously?

MR. HAROLD SURMINSKI: We had to modify it a little bit; wasn't overly onerous.

MR. BOB PETERS: All right. My recollection of what -- where we were having our discussion is that you indicated, certainly in the rebuttal and in evidence to me, that some of your new term-sheeted export arrangements contained and will contain provisions of import guarantees in the drought years.

Is that correct?

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

MR. BOB PETERS: And these import

guarantees, you call them "energy guarantees," correct?

MR. HAROLD SURMINSKI: Yes, we do under adverse flow conditions.

MR. BOB PETERS: Adverse flow means drought years? Below-dependable years?

MR. HAROLD SURMINSKI: Dependable, equal to dependable.

MR. BOB PETERS: Or below?

MR. HAROLD SURMINSKI: Or below.

MR. BOB PETERS: By definition, do you have below-dependable flows?

MR. DAVID CORMIE: Below-dependable flows are a possibility, but that's not what Manitoba Hydro plans for.

MR. BOB PETERS: So when you say you have import -- import guarantees, you're thinking that they would apply in the years in which you have dependable flow, which is your low-flow years?

MR. DAVID CORMIE: They are available, yes.

MR. BOB PETERS: And, Mr. Surminski, does Exhibit 19 demonstrate to the Board the quantum of those import guarantees under the Minnesota Power sale and the Wiscwon -- Wisconsin Public Service sale?

MR. HAROLD SURMINSKI: Yes, they are

included in the input category as the common -- that's the bottom line, just -- just in the first block, just above the total power resources, WPS/MP proposed sale and the imports that start at three eighty-three (383) in 2018 and go up to as high as twenty-three zero one (2301) in 2023.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Surminski, I'm looking at Table A-1, and I'm going down to your imports. And I see -- I see a "Total Contracted" line item.

Are you there?

MR. HAROLD SURMINSKI: Yes, I am.

MR. BOB PETERS: Can you explain to the Board what "total contracted" means?

(BRIEF PAUSE)

MR. HAROLD SURMINSKI: Yes, a total contracted means guarantees or import return energy associated with other -- with sales other than the NSP500 extension and the -- the new WPS and MP.

And in this case, the eight hundred (800) would be an assumption with the diversity, that the diversity sales would be continued and the guarantee associated with that would continue.

MR. BOB PETERS: So the first line, "Total Contracted," is not to refer to the NSP sale or the Wisconsin Power sale.

MR. HAROLD SURMINSKI: It is the earlier form of the NSP sale, until it becomes the extended in 2015.

MR. BOB PETERS: And after 2015, on that "Total Contracted" line, when it drops down to 800 gigawatt hours a year, that's the diversity arrangement that Manitoba Hydro assumes will continue?

MR. HAROLD SURMINSKI: Yes.

MR. BOB PETERS: And factually, will it continue? There's no -- or is there a contract in place, or not yet?

MR. DAVID CORMIE: There's no contract in place yet for that.

MR. BOB PETERS: But you expect to put one in place?

MR. DAVID CORMIE: Yes, we do.

MR. BOB PETERS: All right. Then going to the NSP Xcel sale extension, this is, in a way, a continuation of -- of what you had previously with NSP and Xcel?

MR. DAVID CORMIE: Yes, it is. The existing diversities go all the way to 2019. And as part of our negotiations on the extension of the -- the sale, we intend to renegotiate the diversities and -- and start them under different terms and conditions back in 2015.

And that energy guarantee is the energy guarantee that would be associated with the -- the terms of the diversity sale that have been agreed to by -- by Xcel as part of the 500 megawatt sale extension.

MR. BOB PETERS: Is that under contract?

MR. DAVID CORMIE: We have a binding term sheet for that.

MR. BOB PETERS: And then, if we're looking at the WPS, the Wisconsin Public Service sale, there's also some import guarantees coming back from that utility?

MR. DAVID CORMIE: Yes, and it's more than a guarantee that there is a 500 megawatt power purchase call option that we've negotiated.

MR. BOB PETERS: In terms of the imports that you're getting, are those annual guarantees whenever needed by Manitoba Hydro, up to an annual maximum?

MR. DAVID CORMIE: Those numbers are the -- the maximums that are available in any year.

MR. BOB PETERS: Yes, I understand that

those are the maximum available in the year.

Does Manitoba Hydro have to take them at any specific time during the year, or is that the maximum available when called on by Manitoba?

MR. DAVID CORMIE: You're -- you're correct, Mr. Peters, it's a call option. It's Manitoba Hydro's option to buy the energy if required.

MR. BOB PETERS: And there's no monthly or daily limit required?

MR. DAVID CORMIE: The only limit is that it's limited to 500 megawatts in any one (1) hour. With the diversity or the Xcel sale extension, it's limited to 350 megawatts in any hour.

(BRIEF PAUSE)

MR. BOB PETERS: Thank you. Mr. Dudar --

MR. DAVID CORMIE: Mr. Peters, I just wanted to point out that you'll notice that the surpluses that are created at the bottom of that table, in -- in all years, they're positive for the years of the sale, and they exceed the -- the energy guarantee from the Wisconsin and the MP Power sales.

So the energy guarantees are not needed to serve the sale. The sale to Wisconsin and Minnesota

Power is coming out of new hydraulic. It's not coming out a -- a pool of system resources that would -- would include the energy guarantees. But it's a resource that is available for -- for us to use to serve our other requirements.

MR. BOB PETERS: I'm not sure I follow that, Mr. Cormie. When I look down on -- let's pick 2015/2016 fiscal year, I see your total power resources as 31,652 gigawatt hours that year.

MR. DAVID CORMIE: I think, Mr. Peters, you -- you need to refer to a year in which the Wisconsin sale is in service. For example, take the year of say '22/'23.

MR. BOB PETERS: All right. I now have your point. Your point to the Board, Mr. Cormie, is that the surplus, the bottom line number, literally, on that page, shows that the import energy that may be coming from Wisconsin is not needed and you'd still have a surplus.

MR. DAVID CORMIE: That's correct. And -- and the intent of those sales is that they will be made out of new hydraulic resources, not out of energy that's purchased in the low flow year to serve the sale. So the -- the whole concept there is that Wisconsin wants to buy new hydro power; they don't want to buy power that they've supplied to us and -- and we're returning it to them.

MR. BOB PETERS: This question goes by my memory, Mr. Cormie. I thought at the GRA, you told the Board that not only were you extending the NSP/Xcel sale but there was a new sale to Minnesota and also a new sale to Wisconsin.

Am I correct in my recollection?

MR. DAVID CORMIE: No, you're not correct. I wasn't at the hearing in -- in April, but Mr. Surminski may remember that.

MR. BOB PETERS: Point taken. Mr. Surminski, was there a Minnesota Power sale mentioned to this Board at the General Rate Application?

MR. HAROLD SURMINSKI: Yes, and it's included in the -- in the WPS/MP -- the last line is the combination of the two (2).

MR. BOB PETERS: Thank you. Now, Mr. Dudar, you had indicated in your evidence, through your counsel, I think to myself and also to Mr. Landry, that one (1) of your responsibilities was to physically meet with Manitoba Hydro's top ten (10) customers and discuss this Energy Intensive Industry Rate that's now before the Board?

MR. MICHAEL DUDAR: That's correct.

MR. BOB PETERS: Did you in fact physically meet with -- with all ten (10) or were some of these conversations over the phone?

MR. MICHAEL DUDAR: Some were in person and some were over the phone.

MR. BOB PETERS: And as part of your discussions with these companies, these are the companies that, in fact, gave you their load forecasts, and that's what we've talked about the last two (2) or three (3) days.

MR. MICHAEL DUDAR: That's correct.

MR. BOB PETERS: When you -- have you recently had discussions with them in light of the economic turmoil that seems to be existing in the world?

MR. MICHAEL DUDAR: We've had some discussions and their plans have changed. Some are -- have deferred moving forward with some of their expansions and others are still continuing as planned.

MR. BOB PETERS: Continuing as planned, at least at this point in time?

MR. MICHAEL DUDAR: That's correct.

MR. BOB PETERS: And the reasons for some of those plans changing would be because economic hardship may befall some of those ten (10) companies, correct?

MR. MICHAEL DUDAR: That's correct.

MR. BOB PETERS: And does Manitoba Hydro have an ability to monitor the fiscal health of those top ten (10) customers? Is that something you do?

MR. MICHAEL DUDAR: We do credit checks on customers. I'm not sure exactly what the -- the framework is for doing that, but I know we do that on occasion.

MR. BOB PETERS: But, for example, the share prices on those that are publicly traded, are you -- does Manitoba Hydro follow those and monitor the -- the share capital of those companies?

MR. MICHAEL DUDAR: My account managers do do that sort -- sort of thing.

MR. BOB PETERS: And as a result of your monitoring, do you also find out what their annual revenue expectations are and which companies may be in a situation where they forecast losses as opposed to profits?

MR. MICHAEL DUDAR: My account managers do that as well.

MR. BOB PETERS: And they do that through information received from these companies themselves?

MR. MICHAEL DUDAR: It's a combination of information they've received from companies and information they garner from the annual reports.

MR. BOB PETERS: Would it be fair to say that, collectively, all ten (10) of your top ten (10) customers are either suffering or starting to suffer as a result of economic turndown?

MR. MICHAEL DUDAR: I -- I would say that's probably fair to say.

MR. BOB PETERS: Can you indicate to this Board the magnitude of such economic impact?

MR. MICHAEL DUDAR: No, I can't.

MR. BOB PETERS: What about in terms of -- I think earlier in the proceedings I probably threw out a number of approximately 700 gigawatt hours of growth that was being targeted.

Relative to that number of 700 gigawatt hours, can you indicate to this Board what the downturn will actually result in, in terms of growth, at least as your plans are today?

(BRIEF PAUSE)

MR. MICHAEL DUDAR: I -- I'd say probably about a quarter to a half of it could be -- could be deferred to some point in the future. Some of it is associated with environmental load changes, and depending on -- on legislation and regulation, that my be required to go forward anyway.

MR. BOB PETERS: Thank you, Mr. Dudar. Does that mean that the revenue forecast that you have provided to the Board would also -- maybe should be downgraded, at least in the near term by 25 to 50 percent?

MR. MICHAEL DUDAR: No, my -- my changes are primarily for -- for customers that were in the mining and the -- the pulp and paper industry.

MR. BOB PETERS: And so the -- the sectors of the economy, such as the pipeline and the chemical industry, you're not, at this point, aware as to what downturn, if any, they will face in the upcoming months or years?

MR. MICHAEL DUDAR: No.

MR. BOB PETERS: And those changes in -- in growth forecasts are not reflected in any of the filings that are before the Board, in terms of the growth above baseline or the growth below baseline, because those were based on a previous load forecast, correct?

MR. MICHAEL DUDAR: That's correct.

MR. BOB PETERS: Was that the '08 forecast or the '07?

MR. MICHAEL DUDAR: The customer's -- the customer's expansion plans are -- are fluid and they change on -- on regular basis, and numbers that we received for the '08 forecast would have been modified slightly, based on conversation. But I -- I'm really referring to information that -- that we had -- conversations I've had with customers in the recent times.

MR. BOB PETERS: Indicating that the '07 forecast is still relied on by the Corporation as being accurate for purposes of this application?

MR. ROBIN WIENS: That would be the '08 forecast, Mr. Peters.

MR. BOB PETERS: Sorry, the -- the '07/'08 fiscal '08 forecast.

MR. ROBIN WIENS: The forecast that would have completed in May or June of 2008.

(BRIEF PAUSE)

MR. BOB PETERS: In the book of docu -- I'm sorry, Exhibit 17, I had a question on that document. It was a filing. And if you're looking for Manitoba Hydro Exhibit 17, Mr. Wiens, I think this may have been information you put on the record, and your counsel had it also reduced to writing.

(BRIEF PAUSE)

MR. ROBIN WIENS: Yes, Mr. Peters.

MR. BOB PETERS: And at the same time, if we're turning up documents, Mr. Wiens, in the book of documents, Tab 6, in the last page of the book of documents, Tab 6, contains some actual load growths for the General Service Large class. I might have a couple of questions on that as well.

Mr. Dudar, when -- when would the Board expect your -- your next load forecast to be completed?

MR. ROBIN WIENS: Typically, there's a load forecast completed every year in May.

MR. BOB PETERS: All right. And now, on Exhibit 17, you have used the specific load, you -- you wanted the Board's attention to be brought to the General Service Large, but the 300 to 100 kV subclass, correct?

MR. ROBIN WIENS: Well, specifically, because some of the industries that would be affected by this rate fall into that subclass, we believed it was appropriate to incorporate the forecast domestic loads for that class into the -- into the comparison that was earlier provided by MIPUG in their exhibit.

MR. BOB PETERS: And in doing so, would you -- would it be correct that the subclass of General

Service Large 300 to 100 kV will in fact have the largest growth of the three (3) subclasses under General Service Large?

(BRIEF PAUSE)

MR. ROBIN WIENS: I -- I think that may be possible. I'm -- I'm just trying to source some numbers here, and I'm not quite able to do it in realtime.

MR. BOB PETERS: All right, well, you can take that subject to check, if you would, Mr. Wiens.

Would it be correct to say, Mr. Wiens, that the Energy Intensive Industry Rate before this Board is to target some of that 652 gigawatt hours a year growth for that General Service 30 to 100 kV subclass?

MR. ROBIN WIENS: Yes.

MR. BOB PETERS: And while the rate is to target some of that growth, can you indicate to the Board how much of that growth will be targeted and exposed to actually pay the new rate under your present forecasts?

MR. ROBIN WIENS: Again, not in realtime, but -- I would have to go back and look at the Information Request responses we provided. But we could find that number, yes.

MR. BOB PETERS: You're not able to give a ballpark at this time and check it later?

MR. ROBIN WIENS: I think we'd prefer to try to be accurate.

MR. BOB PETERS: Of course, thank you, Mr. Wiens.

At Tab 6 of the book of documents, Mr. Chairman and panel, there is a summary provided in response to one (1) of the Information Requests containing the actuals. And when I look at that, Mr. Wiens, I'm -- I'm looking at the -- the bottom third of the page at Tab 6 of the book of documents, the last -- the last document in the tab.

Again, it's the large -- it's the General Service Large thirty (30) to one hundred (100) that has had the largest growth over the nine (9) years that are shown.

Do you agree with that?

MR. ROBIN WIENS: I haven't done the math, but I think that's right in percentage terms. It doesn't look to appear to be correct in absolute gigawatt hour terms.

MR. BOB PETERS: Right, I was looking at it as approximately a 54 percent growth over those nine (9) years or 6 percent growth a year.

MR. ROBIN WIENS: That looks right.

MR. BOB PETERS: And that's compared to 42 percent growth for the large greater than one hundred (100), which was at about 4 1/2 percent a year annual growth for those nine (9) years?

(BRIEF PAUSE)

MR. ROBIN WIENS: I get 5 and 4 percent, Mr. Peters, but it's pretty close.

MR. BOB PETERS: Mr. Cormie, perhaps over to you, as I -- as I look at -- just one (1) second, please.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Cormie, when we talked about generation capacity constraints, I understood that to be a discussion different than -- than let's say energy constraints, where energy constraints were more because we -- under the line of not having enough water.

And that was your understanding in your evidence?

MR. DAVID CORMIE: Yes. And generation

can be constraining in the context of export sales because Manitoba load may be consuming a greater portion of the generation resource and -- and, therefore, export sales have to be reduced.

MR. BOB PETERS: And that -- that statement really underpins one (1) of the reasons why Manitoba Hydro suggests that the average export price is a proxy -- the average firm export price is a proxy for the marginal cost that should be charged under the energy-intensive rate.

MR. DAVID CORMIE: I -- I don't follow that, Mr. Peters.

MR. BOB PETERS: That's fine, I'll move on. When you say there are generation capacity constraints, Mr. Cormie, does that mean that Manitoba Hydro's maximum generation capacity of approximately 5,000 megawatts is constrained because all existing hydraulic generating stations are -- are being utilized?

MR. DAVID CORMIE: That's right. We -- we -- we don't have enough low cost hydro energy available to fully maximize the export capability of the transmission lines, because at times of the year like today, they're -- the Manitoba customer is using that -- needs that energy. And it -- it -- it means that there's much less energy flowing -- or much less energy flowing on the transmission line than the transmission line is capable, and so the -- the -- there's a limited capability for the -- for the -- for the hydro system to produce megawatts.

MR. BOB PETERS: Is the Brandon coal thermal generating station running flat-out at the time that you say there are generation constraints?

MR. DAVID CORMIE: It may or may not be. It depends on the market price at the time.

If -- if we offer the generation from Brandon to the MISO market and it's an attractive purchase for MISO to make, it will be -- it -- it can be sold to -- and to increase export sales. If the price that -- Brandon is too high, relative to the alternatives in MISO, then it won't run for -- for economic reasons.

So it -- but generally, the cost to Brandon is -- is attractive, compared to the -- the market price. And so generally it would be running -- it's -- it's -- like it's running today, because it's an economic supply of power.

MR. BOB PETERS: But when you tell the Board that the tie-lines are constrained -- I'm sorry, when you tell the Board the tie-lines are not constrained, but the generation is the constraint, when you give that evidence you're also telling the Board that not only are all of they hydraulic resources being used, but so is Brandon thermal plant?

MR. DAVID CORMIE: It could be. Generally in the summertime when the Manitoba load is low enough and -- and the hydraulic generation is running full out, it's not necessary to run Brandon in order to fill the transmission line.

During the daytime, because the Manitoba load is up, the transmission line is -- has extra space available on it -- or has space on it, and the on-peak price justifies running the thermal plant. So in the daytime it may be part of the resource mix; in the nigh time it may be back down.

MR. BOB PETERS: When you tell the Board that the generation capacity constraints exist, as opposed to transmission capacity constraints, are the Brandon and Selkirk natural gas generating plants running?

MR. DAVID CORMIE: They -- they are rarely economic supplies for -- for the MISO market, and -- and so generally they're not -- they're not running. And certainly they wouldn't be running at night under high flow conditions when the tie-line would be loaded and -- and generate -- or transmission constraints would be binding.

The market price might be ten ($10) dollars a megawatt hour and it might cost one hundred ($100) dollars a megawatt to run the -- the combustion turbines. That was kind of made clear by the evidence that was provided by TREE in that predispatch chart that was kind of a checkerboard of black and white squares; that was the MISO day ahead constraint showing -- and -- and generally what happens in that chart is that the -- although we offer the gas turbines in, they're -- there's not enough transmission to make them go to market. But even if we did dispatch, there -- they wouldn't be dispatched because they were une -- they were uneconomic.

MR. BOB PETERS: When we talk of generation capacity constraints, Mr. Cormie, have you included wind in that capacity constraint?

MR. DAVID CORMIE: Generally I wouldn't consider wind to be a capacity resource, because it cannot be -- it cannot be relied on. It -- it's not part of Manitoba Hydro's capacity pool. And to the extent that we -- that wind is offered in, generally we have to back it up with a shutdown of a hydro unit, so it's not considered as a capacity resource, and it wouldn't be part of the generation constrained dispatch.

MR. BOB PETERS: Would you consider the Curtailable Rates Program as a capacity constraint dispatch option?

MR. DAVID CORMIE: No, because the curtailable rates is a capacity program, it's not an energy program, so we do not curtail Manitoba load -- curtailable load in order to make additional energy sales into the market. It's there to -- for other reasons, emergencies, protecting and planning reserves, provide reserves to the system, but it's not there as an energy resource.

MR. BOB PETERS: Is the generation capacity restraint reflective of scheduled imports adding to that constraint?

MR. DAVID CORMIE: Scheduled imports can provide a supply of capacity and energy. Under the situation where the capacity constraints are -- are mixing with the transmission constraints, imports will not be -- they won't -- they won't be part of that mix. Imports are needed when -- when the tie-line is -- is not loaded. Imports never create an overload -- or a fully loading of the export transmission line.

MR. BOB PETERS: Mr. Cormie, in terms of Manitoba Hydro's transmission costs for exports, for their firm -- for your firm exports, that transmission cost is built into the price, as I understood your previous evidence.

Is that right?

MR. DAVID CORMIE: There are -- there are two (2) types of transmission: One (1) is network service, and there's no cost associated with network service. And -- and then there are the firm point-to-point transmission costs that are incurred when Manitoba Hydro purchases firm transmission. Those are sunk costs and those costs aren't associated with individual transactions.

So I think you're -- I think you're correct, Mr. Peters, that it's -- to the extent that a -- that a transaction relies on Manitoba Hydro to purchase transmission service to make an individual transaction, we build that tran -- that transmission cost into it, to the extent that it's a sunk -- already a sunk cost, it's not a part of the calculation.

MR. BOB PETERS: Part of the cost, but not part of the calculation that derives the -- the price?

MR. DAVID CORMIE: That's right. We've -- we've invested in transmission service in all -- in order to have that right. Once you've done that, you've spent that money, and it -- it doesn't enter into the calculation of whether you want to make an incremental transaction or not.

MR. BOB PETERS: And for non-firm exports, Mr. Cormie, what are Manitoba Hydro's transmission costs?

MR. DAVID CORMIE: There are some small scheduling fees and transmission service charges. Generally, they would be a few percent of the cost of the transaction, Mr. Peters, in the order of a few dollars a megawatt hour. They're -- they're relatively small.

MR. BOB PETERS: Mr. Cormie, on Manitoba Hydro Exhibit 15, it was transcript reference 622, you provided a definition of dependable energy sales contracts. I have that as Exhibit 15.

MR. DAVID CORMIE: I have that, yes.

MR. BOB PETERS: And one (1) of the -- one (1) of the points that I would like you to clarify for the benefit of the Board is that when Manitoba Hydro is calculating its revenues from its dependable energy sales, it includes all amounts that are billed for demand charges for the accredited capacity, correct?

MR. DAVID CORMIE: That's correct.

MR. BOB PETERS: It also adds in the amounts billed for the energy that's sold.

MR. DAVID CORMIE: That's correct.

MR. BOB PETERS: And you've now also told us in your evidence that there's -- there may be other revenues received for other services or products that are supplied or available to the counterparty by way of the contract. And that's also included.

MR. DAVID CORMIE: That's correct.

MR. BOB PETERS: I note in the answer to -- in Manitoba Hydro Exhibit 15 that the energy volumes that you have, include all energy sold under contract, whether physically delivered or financially settled, correct?

MR. DAVID CORMIE: That's correct.

MR. BOB PETERS: Now, let me understand that. In the rate that you're building up for the energy intensive rate to Manitoba customers, for which you're asking this Board's approval, you include volumes of energy that have been sold pursuant to long-term contracts as dependable exports, but some of those sales may not physically be delivered by Manitoba Hydro?

Would that be correct?

MR. DAVID CORMIE: That's correct, Mr. Peters. There's -- there's two (2) sides to the calculation: one (1) is the revenue side and one (1) is the cost side.

The revenue side comes from the sale of the power to the customer. And the customer pays Manitoba Hydro that, regardless of whether Manitoba Hydro actually physically generates that power or buys the power in the marketplace in order to serve the sale. And -- and the source of the energy is -- is the cost side.

And, for example, if we were to run our gas turbines in order to serve the sale, we might incur a cost of one hundred dollars ($100) a megawatt hour. If we bought the energy in the market it might be fifty (50).

Regardless of whether we spend fifty dollars ($50) or one hundred dollars ($100) producing the power, the customer will pay us the rate under the contract. And -- and when we -- when we've calculated the revenues from the sale, we include all the revenues from the sale, regardless of where we source the energy from when we actually make delivery.

MR. BOB PETERS: All right. I understand your evidence, Mr. Cormie, that if Manitoba Hydro physically generates the electrons, you know the cost of generating it and you also know the revenues that are gonna be paid by your counterparty, correct?

MR. DAVID CORMIE: Correct.

MR. BOB PETERS: And you're only going to enter into those contracts if there's a profit in it for Manitoba Hydro?

MR. DAVID CORMIE: Yes, we enter into

these transactions on the expectation that they will be profitable for the Corporation.

MR. BOB PETERS: But I now hear you also telling the Board that if your counterparty is supposed to pay you, let me just pick a number, six (6) cents a kilowatt hour, and you know that your generation costs and transmission costs may be a total of four (4) cents, leaving you with a surplus of two (2) cents or a profit of two (2) cents, you can now weigh that against a financial settlement of that deliver.

Is that correct?

MR. DAVID CORMIE: I'm not clear, Mr. Peters, by weigh it against. The -- the important thing is that when we look at the cost of serving the sale under all flow conditions, we -- we calculate them -- the -- you know, the marginal cost of serving the sale. And we have -- we know what the revenues are and we subtract off the marginal costs, and -- and sometimes that marginal cost may be very high if the -- for example, under dependable flow conditions, we'll have to enter into some expensive purchases in order to -- to serve the sale.

But when you look at the costs under all flow conditions from the lowest to the highest, we -- our practice is to calculate the outcome under all those conditions and -- and say that's the average cost of serving the sale. And when we compare the average cost to the revenue that we receive on the sale, that determines Manitoba Hydro's expected profit on the transaction.

MR. BOB PETERS: All right. When you financially settle (1) one of those transactions, you don't physically deliver the electrons, correct?

MR. DAVID CORMIE: That's correct.

MR. BOB PETERS: And when you financially settle those, will you financially settle those so that Manitoba Hydro's profits are actually less than what they would be if Manitoba Hydro physically generated the electrons?

MR. DAVID CORMIE: Well, it depends on -- it depends on our alternate cost at the time. Generally, if we can supply the power cheaper than buying it in the market, we wouldn't -- we would -- we would generate the power in -- and serve the sale off our own resources. If we -- if we can buy the power cheaper than generating ourselves, we will -- we will buy the power to serve the sale.

We're always trying to do what is economic at that moment in time.

MR. BOB PETERS: And -- and I understand

that and I appreciate your answer, but will there be circumstances where you financially settle a transaction so that there would be less profit for Manitoba Hydro than there would be if Manitoba Hydro had delivered its own generated electrons?

MR. DAVID CORMIE: I can't think of a circumstance when we would choose to do something that was uneconomic.

MR. BOB PETERS: And when it comes time to calculating the export revenue received from those sales, do the financial settlements impact on that revenue calculation?

MR. DAVID CORMIE: They don't calculate on the net -- on the revenue calculation, they -- they would calculate -- they would influence the calculation of net revenue, which is the revenue minus the cost. A

nd generally, we only make sales that -- that we are capable of delivering on. And from Mr. Surminski's perspective, he might, from a planning perspective, say that the gas turbines are there and we'll run them. But when -- when our power traders are actually, at the moment of delivery, although they have the gas turbines there, if there's an opportunity to acquire the power at a lower cost, we will do that rather than -- than running the -- the gas turbines.

And so we're always trying to find less expensive ways of serving the sale and improving the margin that Manitoba Hydro would receive for the sale of that power under the dependable contract.

(BRIEF PAUSE)

MR. BOB PETERS: Let me see if I have that summarized properly this way, Mr. Cormie. If you financially settle, as opposed to physically deliver, does that change the price that Manitoba Hydro will get from the contract in any way?

MR. DAVID CORMIE: No, it doesn't.

MR. BOB PETERS: Mr. Cormie, in -- in Document 8-4 of the book of documents, and in light of the financial trading answers you've given me, I need to be clear, and I -- I, quite frankly, am not clear on whether there are any merchant transactions included on either the top half or the bottom half of that chart.

MR. DAVID CORMIE: There are no merchant transactions in these numbers, Mr. Peters.

MR. BOB PETERS: And Mr. Cormie, I handed out some extracts from the record, including PUB/Manitoba Hydro-16A, and questions I was going to ask of you. And that was a schedule of the '07 fiscal year and the '08 fiscal year on-peak and off-peak energy sales.

Do you remember that?

MR. DAVID CORMIE: Yes, I have that.

MR. BOB PETERS: Are there merchant transactions included in any of the numbers in PUB/Manitoba Hydro-16A?

MR. DAVID CORMIE: There are none.

MR. BOB PETERS: And while we're talking about those merchant transactions, Mr. Cormie, would I be correct that in those transactions, the profit to Manitoba Hydro may be less than two (2) cents a kilowatt hour, but in every instance there's a profit to Manitoba Hydro?

MR. DAVID CORMIE: There are thousands of transactions in merchant transactions. In every case, they are -- there may be -- there may be profits greater than two (2) cents, there may be profits less than two (2) cents. Not all the transactions are profitable.

If my -- my memory serves me right for the year ending 2000 -- March 2008, approximately 90 to 95 percent of the transactions were profitable, Mr. Peters.

MR. BOB PETERS: At the time the transaction is entered into, is there an expectation of profit, or is there an understanding it will be unprofitable when made?

MR. DAVID CORMIE: There's always -- there needs to be an expectation of a profit.

MR. BOB PETERS: So you don't have your transmission, or your -- your acquisition price, or your selling price locked in at the time you make those?

MR. DAVID CORMIE: We -- we may have purchased transa -- transmission service in advance of -- of the opportunity, Mr. Peters, so we're held with the sunk cost of the transmission purchase. And so there are days when Manitoba Hydro records a loss on those transactions because it's chosen not to trade, but we show that we -- we went and purchased some transmission service. And so there can be those -- those days where we -- where we show that the trading activity has lost money.

But the vast majority of the transactions -- the trading transactions are entered into only when they're -- we can lock in a positive spread. And the losses I'm talking about are our losses associated with the buying the transmission service.

MR. BOB PETERS: What was the fiscal 2008 profit received from the trading transactions by Manitoba Hydro?

MR. DAVID CORMIE: For year end 2008, revenues were 71.5 million and the expenses associated with those were 60.4 million. And so the trading profit was approximately $11 1/2 million from which there were some transmission service charges that need to be paid, reducing that by approximately $4 million.

So the profit on the merchant transactions in that year were approximately $7 million.

MR. BOB PETERS: I'd understood the revenue -- I'm sorry, no, the cost of transmission was over and above that and, therefore, was deducted from the profits? I thought that was built into the equation, Mr. Cormie.

MR. DAVID CORMIE: Well, as I mentioned earlier, we may purchase transmission service for a month or for a year in advance. And once that transmission is purchased, we use it on a daily basis, but there may be some days where the transmission service has been bought and paid for but no -- no energy flows, and so we have expenses on that -- on that day that need to be paid.

For transactions that are made on a daily basis where we buy transmission service, those costs are built into the -- into the cost of -- of that specific transaction. There's no pre-commitment by Manitoba Hydro and so, you know, when we look at whether we would enter into an incremental transaction, we would consider the spreads that we can expect between the markets plus the incremental cost of buying transmission service.

MR. BOB PETERS: All right, thank you. I have your clarification. I want to turn, if I could, to your Exhibit 12, Mr. Cormie. And I say "your", meaning Manitoba Hydro's Exhibit 12.

This was one of those curves that was drawn and this one was picked for the month of July of '07 on-peak summer month high water flows.

Do you recall that?

MR. DAVID CORMIE: Yes, I have that.

MR. BOB PETERS: And in response to a question by Mr. Landry, you provided a number of scenarios and this is one of them, correct?

MR. DAVID CORMIE: That's correct.

MR. BOB PETERS: Can you confirm that this curve for July of '07 shows what are net exports, as opposed to gross exports?

MR. DAVID CORMIE: I -- I can confirm that with the qualification that this is net interchange. This is the -- this is the actual power that's flowing on the transmission line -- the transmission lines. These are by all customers of -- of Manitoba Hydro who take transmission service. These are not just Manitoba Hydro trans -- transmissions -- transactions, although I can say for sure that all the transactions below the firm limit are Manitoba Hydro transactions because Manitoba Hydro owns all the firm transmission service.

MR. BOB PETERS: Maybe you're ahead of me, but what you are telling the Board is that in addition to Manitoba Hydro's sales, there's -- there's something else going on on this graph? Somebody else's sales?

MR. DAVID CORMIE: Yes. For example, if Manitoba Hydro were to sell 2,000 megawatts on the line, but at the same time SaskPower would -- was buying a hundred, then flow in the line would only be nineteen hundred (1,900), because there's two thousand (2,000) going south and a hundred coming north, so the net flow on the line -- the net interchange is -- would be nineteen hundred (1,900).

Pardon me? No, Saskatchewan can buy transmission service out of MISO through Manitoba into Saskatchewan.

MR. BOB PETERS: Does this also net-off imports?

MR. DAVID CORMIE: Yes, and that -- that was the -- that was the example I just gave you. If Saskatchewan were choosing to buy power out of MISO at the time that Manitoba Hydro was exporting, then any imports that were occurring would -- would reduce the export flow. And so to the extent that imports were scheduled, the net flow would be reduced.

MR. BOB PETERS: I'm not sure if it's a different category, Mr. Cormie, but it would also -- those net exports, would -- would that exclude -- or I'm sorry, would that be reflective of having netted-off external trading or resales?

MR. DAVID CORMIE: No, the merchant transactions do not -- do not flow through Manitoba or originate in Manitoba. These are transactions that are external to Manitoba. And so merchant transactions do not reflect on the flow on Manitoba Hydro's transmission lines.

MR. BOB PETERS: Can you confirm on that exhibit, Mr. Cormie, that the zero decimal five zero (0.50) probability of accedence reflects the average net interchange of about 1,800 megawatt hours -- or megawatts, sorry?

MR. DAVID CORMIE: Yeah, that -- that's the median -- that's the median flow. Fifty percent of the time the flow is higher than eighteen hundred (1,800) and 50 percent of the time it was less than eighteen hundred (1,800).

MR. BOB PETERS: And if I calculate that to -- to get on-peak, that would be equivalent to approximately 625 gigawatt hours?

MR. DAVID CORMIE: That sounds fair.

MR. BOB PETERS: But when I compare that 625 gigawatt hours to that PUB/Manitoba Hydro-16A Information Request that we talked about a few minutes ago, their July of '07 on-peak seems to indicate 785 gigawatt hours.

Am I correct in that?

MR. DAVID CORMIE: That's what 16A shows. And the -- the explanation there, Mr. Peters, is one (1) is sales and one (1) is deliveries. Sales are the megawatt hours that Manitoba Hydra has sold and received revenue for. And not all sales go to delivery and -- and so they're -- they're -- you're comparing apples and oranges.

MR. BOB PETERS: Well, at least they're all fruit. But what you're telling me is that the ones that don't go to delivery, go to financial settlement, is that what I read between the lines of your answer?

MR. DAVID CORMIE: Yes. And -- and a good example to -- to put clarity on this, is that there are -- in -- in MISO there's a day-ahead market and there is a realtime market.

In the day-ahead market is energy transactions that are expected to take place in realtime.

And Manitoba Hydro gets paid for those day-ahead transactions, prior to making -- making delivery.

But in realtime we may change our mind, and we may decide not to export the amount that we were paid for in the day-ahead market. We may decide to export less, and then divert the difference to a different market. For example, it might be Ontario.

And so, you can imagine a situation where we said on a day-ahead basis we were going to sell 2,000 megawatts to MISO. In realtime, we decide we're only going to sell 1,900. But we show 2,000 megawatts of sales in the day-ahead market. But in realtime, now, we've bought back, or in effect, under-delivered, and we've sold another hundred again to Ontario.

So now you have double counting. We've -- we've sold the megawatt hour twice.

And so that's why the sales numbers are bigger than the deliveries, because under this market construct, you get to sell the power twice if you choose to. And -- but -- but that means that you have to -- you have a purchase cost because you have to -- you have to serve your day-ahead obligation with the purchase.

And this goes back to the -- the -- you have to look at the net value to Manitoba Hydro for doing that. And if -- if the realtime price in -- in Ontario is better than the MISO price, it may make economic sense to -- to purchase to serve the sale that you made in the day-ahead market, and -- and capture the additional margin that's available between the Ontario and the MISO market.

MR. BOB PETERS: So on those days when you sell the same energy twice, in one (1) of those transactions you will have to financially buy it back?

MR. DAVID CORMIE: That's correct, so there's a cost associated with -- with the under-delivery.

MR. BOB PETERS: And then, from that answer, do I take it that you can schedule more than tie-line capacity?

MR. DAVID CORMIE: In the day-ahead market you can schedule more than the tie-line capacity, because MISO will only accept say -- they will only accept sales up to the capability of the transmission line, because you -- there's no -- MISO doesn't know whether you were -- you're going to enter into a arbit -- arbitrage transaction in -- in real time.

MR. BOB PETERS: So the answer is no, you cannot schedule more than the tie-line capacity?

MR. DAVID CORMIE: I agree.

MR. BOB PETERS: Okay, I'm sorry. I may

have misunderstood the start of your answer.

(BRIEF PAUSE)

MR. BOB PETERS: Perhaps let me close on that PUB-16 and also on Undertaking Number 7, which is Manitoba Hydro Exhibit 12, when I look to the month of August, 2007, that's the month that I think that Mr. Ostergaard would say that somebody at Manitoba Hydro was the highest paid trader.

There it shows 981 gigawatt hours on-peak, sold, correct?

MR. DAVID CORMIE: That's correct.

MR. BOB PETERS: And you don't have the physical capability to deliver that in that month, that's also correct?

MR. DAVID CORMIE: That's correct.

MR. BOB PETERS: So what --

MR. DAVID CORMIE: That works out to an average export in the on-peak hours of 2,667 megawatts, which is much higher than the physical transfer capability to all our markets.

MR. BOB PETERS: So that tells the Board that you sold the same energy twice on that day, and that somewhere there's a financial transaction that would --

would bring that back to tie-line capacity?

MR. DAVID CORMIE: That's correct.

MR. BOB PETERS: And there's no record -- no place in the record where the tie-line capacity -- sorry, where those financial buyback situations is reflected in terms of the amount of energy that was -- was paid for financially as opposed to delivered?

MR. DAVID CORMIE: I -- I've done the calculation, Mr. Peters, and for these two (2) years, approximately 5 1/2 percent of the transactions are financial transactions. The other 94 1/2 percent go to physical delivery.

(BRIEF PAUSE)

MR. DAVID CORMIE: That -- that's in terms of the megawatt hour.

(BRIEF PAUSE)

MR. BOB PETERS: In light of that answer, Mr. Cormie, when I look at the average prices that you received -- and let's pick August of '07 -- have you subtracted out of that then, all of the transmission costs and those costs associated with the financial transaction?

MR. DAVID CORMIE: No, Mr. Peters, those are just the revenues that Manitoba Hydro received. The costs associated with the purchases aren't part of the revenue calculation.

MR. BOB PETERS: So -- so some of those financially settled transactions, the revenue from that is included in the average price, even though it wasn't physically delivered?

MR. DAVID CORMIE: The -- yeah, the revenue is the revenue that we received from our customer. The financial settlement is a cost and it will show up in fuel and power purchased in another line of the operating statement.

MR. BOB PETERS: So it wouldn't be correct for me to call those net sales?

MR. DAVID CORMIE: That's correct.

MR. BOB PETERS: All right. Mr. Chairman, I'm a little longer than I thought I'd be, but I do want to thank the panel for indulging me in those questions. Those are all that I have at this time.

THE CHAIRPERSON: Thank you. Remind me, if you don't mind, Mr. Peters --

MR. BOB PETERS: Yes, sorry, Mr. Chairman. I think it would be appropriate to canvass my colleagues opposite, to see if they likewise have some questions of the Hydro panel, based on any undertakings or exhibits that have been filed. And following that, we would maybe take a short recess and then we'll reconstitute the MIPUG witness for the conclusion of their direct evidence.

THE CHAIRPERSON: Thank you. Mr. Williams...?

MR. BYRON WILLIAMS: No, Mr. Chairman. I'm just going to sit in awe of the fine job that Mr. Peters just did.

THE CHAIRPERSON: Mr. Landry...?

MR. JOHN LANDRY: Mr. Chair, again, I -- I don't want to be a dampener on the process but the amount of information that's coming at us since -- well, I'll go from the rebuttal but mainly since the beginning of the hearing, because that's -- that's this stuff that I'm trying to figure out -- is simply at too fast a pace.

I'm simply not in a position, Mr. Chair, to meaningful -- meaningfully look at this information -- this new information, to even be helpful to my clients to help explain to them to get meaningful instructions to come back to try to ask questions that might be helpful to you.

And, sir, I say that with all due respect to my friends at Manitoba Hydro, but the difficulty is this is the exact type of information that should have been filed with the application. These are the type -- this is the type of information that you were seeking -- when I say you, sir, I meant -- I mean the Board -- was seeking in their -- in their material.

If that was properly provided, we would have gone through the normal discovery process, which is -- which is very important to your process. It's important to all regulatory processes that I'm aware of. We weren't able to do that.

We, over the last number of days, have been trying to track -- you know every day, there's more undertakings that are filed with information that I will say to you, sir, should have been filed with the application. I will -- and I'll make that argument.

And -- I can't keep up. I just can't keep up and -- and the problem with that is that there's all this information on the record. I understood -- and that's no reflection on Mr. Peters -- I probably understand about 50 percent of what was going on there and that's not a good thing.

But having said all that, sir, I'm -- I understand where we're at, how we got here. It's just a bit frustrating for myself and my clients to have to deal with this type of thing.

I still -- I'm no further ahead on how we determine the average price, based on some of these graphs and everything, but I'm not in a position at this point in time, to -- to ask any questions, at least in relation to the undertakings.

I do have one (1) question that arises out of Mr. Peters, just because it -- it did -- it was one (1) thing I thought I understand and now I don't. I wonder if I could ask that one (1) question and we -- and that'll -- that'll have to suffice unfortunately in the circumstances, Mr. Chair, from our perspective.

THE CHAIRPERSON: Yes, please ask the question.

RE-CROSS-EXAMINATION BY MR. JOHN LANDRY:

MR. JOHN LANDRY: Mr. Cormie, again, just trying to understand, we had dependable energy sales in Tab 8 of Mr. Peters' book of documents, 8-4, which is a -- which was a table I know that you had prepared, and I thought I had some -- some understanding there. We're now talking about financially settled transactions; that's some of the debate you had with Mr. Peters.

First of all, is it -- is it my understand that that is the first time on the record that we've seen this concept of financially settled transactions, in this proceeding at least?

MR. DAVID CORMIE: At this hearing?

MR. JOHN LANDRY: Yes.

MR. DAVID CORMIE: I believe so, yes.

MR. JOHN LANDRY: And if I understood the cross-examination that -- that went on or the questioning that went on from Mr. Peters, when Manitoba Hydro calculates the average firm sale price, the proxy that we've all be talking about, within that there may be a number of transactions that, in fact, were financially settled as opposed to physically settled.

Is that a -- is that a...?

MR. DAVID CORMIE: That's correct, but it -- at the end of the day, the -- that table is a table of revenues. It's not a table of net revenues and it's not a table of cost; it's the revenues that we receive for this -- for the sale.

And that revenue would happen whether we financially settled the transaction or not.

MR. JOHN LANDRY: I -- I think I understand that, sir. But you're telling me that the price that Manitoba Hydro is suggesting that these three (3) or four (4) customer pay, includes some financially settled transaction where there is nothing, no analysis, no detail on the record in relation to those transactions.

Is that right?

MR. DAVID CORMIE: Well, I'm -- I'm suggesting that whether the transaction is financially settled or not is not material to the revenue calculation from those sales contracts.

For example, Manitoba Hydro may choose to run its combustion turbine. We will buy the gas from a gas company. There's a cost associated with serving that sale, and that cost goes to a gas broker in Alberta. That cost is no different than if Manitoba Hydro goes to the market and buys power to serve the sale.

The revenue is -- is fixed under the contract; there's a cost associated with it. The least expensive way of serving the sale is to buy the -- the power directly, rather than to generate it.

The costs and the revenues are separate. We've never put costs associated with these transactions on the table. The rate is based upon the -- the pool of dependable contracts of -- the revenues from those contracts. It's not a marginal cost rate; it's the rate from the contracts, not -- it's not a marginal cost rate.

MR. JOHN LANDRY: Sir, I know you're trying to be helpful to this Board. My question, I thought, was pretty specific. I'll make it a little bit more specific.

There's nothing on the record that these two (2) or three (3), four (4) clients -- or customers that are going to be impacted at this rate, can look at these financially settled transactions and look at the type of detail that you're talking about now.

Is that -- is that a fair statement?

MR. DAVID CORMIE: That's correct.

MR. JOHN LANDRY: And, sir, as I understood what you said, 5 1/2 percent of the transactions that are taken into account are financially settled transactions; that was my note.

Did I have that right?

MR. DAVID CORMIE: Five and a half percent of the transactions shown on PUB-16, which is this -- which was all opportunity in firm sales, most of the financial transactions would be associated with opportunity sales. I didn't do the calculation to find out what that breakdown -- and I'm not sure I have that -- that detail.

But for all -- all sales out of Manitoba hy -- out of Manitoba Hydro, opportunity and dependable sales, it was 5 1/2 percent. I would -- my -- my judgment is that the vast majority of the dependable sales would be physically delivered; they wouldn't be curtailed. It would be the curtailment of the opportunity sales that would then be financially settled.

MR. JOHN LANDRY: But there's nothing on the record that a customer of Manitoba Hydro can test your judgment.

A fair statement?

MR. DAVID CORMIE: That's correct.

MR. JOHN LANDRY: Okay. Now, the other -- the other point, sir, is that as I understood the issue -- and -- and I may be wrong, and plea -- please correct me if I am wrong -- that there were potentially some incremental transmission costs that might be incurred as a result of a financially settled transaction.

Is that a fair statement?

MR. DAVID CORMIE: Incremental transmission service costs are associated with the physical delivery of power and they wouldn't be associated with the -- the financial settlement, no.

MR. JOHN LANDRY: Well, sir, I'm -- then I'm really confused, because as I understood -- and I have the numbers here -- you said that there was an $11.5 million merchant trading profit, that's my word, if it's not completely correct. And then you said there was a $4 million amount that had to be taken off for -- I thought

I heard, and I -- it could be wrong, sir -- incremental transmission services.

Was I not right in that?

MR. DAVID CORMIE: You -- you heard correctly, but that -- those transmission costs are associated with the -- the merchant transactions that aren't transactions that flow in and out of Manitoba. So those are transactions that occur off the system and they don't -- they're not part of this -- these opportunity sales or these dependable sales.

MR. JOHN LANDRY: So when you financially settle a transaction, that's a -- let's use dependable sales -- when you financially settle a transaction, you will never have a transmission -- an incremental transmission cost in another jurisdiction?

MR. DAVID CORMIE: No, because you were -- well, all we have to do is buy the energy. We don't have to provide this transmission service for it.

MR. JOHN LANDRY: Mr. Chair, those are all the questions I have.

THE CHAIRPERSON: Thank you, Mr. Landry. Mr. Gange...?

MR. BILL GANGE: I have no questions.

THE CHAIRPERSON: I think we are going to take a break now. It'll give us all a chance to ponder what we have heard in the last half hour or so.

--- Upon recessing at 2:20 p.m.
--- Upon resuming at 2:40 p.m.

THE CHAIRPERSON: Ms. Ramage, I believe you got some more information for us.

MS. PATTIE RAMAGE: Yes, Mr. Chairman. During Mr. Peters' cross-examination this afternoon, on undertakings, he asked Mr. Wiens, and I -- I'm not sure if I'm phrasing this correctly, but from my notes: How much of the growth in the 30 to 100 kV category would fall into the second block?

Mr. Wiens undertook to provide him with this -- that information, and I believe he now has that.

THE CHAIRPERSON: Mr. Wiens...?

MR. ROBIN WIENS: Yes, and I'm -- I'm taking -- taking the question as meaning in the years that were included in -- the forecast years that were included in Manitoba Hydro Exhibit 17.

And so for 2010/'11, the portion of the forecast large 30 to 100 kV load that would be above the baseline would be 259 gigawatt hours, and the same figure for 2013/'14 would be 280 gigawatt hours.

(MANITOBA HYDRO PANEL STANDS DOWN)

THE CHAIRPERSON: Thank you, Mr. Wiens.

We are going to move on now to the cross-examination of the MIPUG panel, but first, Mr. Landry, Mr. Williams, and Mr. Gange.

Mr. Landry, the Board hears you, and if you have any more questions of Manitoba Hydro's panel before we close tomorrow, we would appreciate it if you would advise the Board counsel. We will take it under advisement.

Alternatively, between now and closing submissions you come to that conclusion and want to ask more questions, again please consult with Mr. Peters. Let us know through Mr. Peters.

And, of course, you have closing argument to make any submissions that you may want to make on either the process or the merits of the case.

MR. JOHN LANDRY: Thank you Mr. -- Mr. Chair. I appreciate that.

THE CHAIRPERSON: Thank you, Mr. Landry. Okay, we will begin now with the cross-examination of the MIPUG panel, and --

MR. JOHN LANDRY: Sorry, we're -- we're still in direct, Mr. Chair. Just a little bit more of direct.

THE CHAIRPERSON: Okay. I must be fading faster than others. Please?

MIPUG PANEL:

ANDREW MCLAREN, Resumed
PATRICK BOWMAN, Resumed
PETER OSTERGAARD, Resumed

CONTINUED EXAMINATION-IN-CHIEF BY MR. JOHN LANDRY:

MR. JOHN LANDRY: Mr. Bowman, do you want to finish the -- I guess it was the last section of -- of the overview that you've presented at the beginning of your direct?

MR. PATRICK BOWMAN: Yes, thank you. good afternoon, Mr. Chair, and members of the panel. The last item that we did not get to finish this morning, in respect of the direct, relates to Appendix B of the InterGroup evidence. The -- the pages are numbered starting B-1 and -- and sequentially thereafter to deal with Appendix B.

This is the section of our submission. If you'll recall, at the start I said we -- we spent time looking at Hydro's basic facts that were being asserted in support of the rate, as well as Hydro's proposal.

We've now spent some time dealing with -- with our comments on Hydro's proposal. This was where we -- we put the discussion in the appendix about some of the items that were being asserted and -- and the extent to which we found that they either borrowed or didn't bear out on a look at the evidence that was -- that was filed.

There are five (5) appendices; four (4) of them received comment in Hydro's rebuttal. It forms the -- the bulk of their rebuttal. So I'll deal with their rebuttal topics as we go along, and that way we'll sort of deal with it all in one (1) and, hopefully, keep fading to a minimum.

Appendix B, the first topic that's there, timely, was an attempt to take a bit of time with the question of what is an appropriate proxy, and to what extent does a linkage to firm exports represent the revenues or the -- the cost impacts on Hydro -- the opportunity cost impacts on Hydro, from a change in industrial load.

This is the topic area where we get into the entire question about tie-lines, and generation constraints, and the like. And we -- we dealt with it in an appendix in part because, from our perspective, not much turns on it. In -- in a sense, without being pejorative, a lot of the discussion that's happened to date is a -- a bit of a tempest and a teapot.

The issue of transmission constraints and whether they exist or not, at a high level, I'll say, doesn't change materially any conclusion we would have in respect of whether their -- they -- their proposal is acceptable or not. That's a general comment.

At a more specific level, when you get to the -- the technical point, determining whether there's a transmission constraint and whether it's -- exists in most hours of the day and whether it's -- only exists when you consider gross exports versus net and a number of other considerations -- as opposed to a generation constraint -- is -- is an interesting academic exercise.

If in deed transmission is not the constraint, the new world we're into is generation is a constraint. It's certainly a surprising change for a lot of us who have sat here through seven (7) years of -- of hearings about transmission constraints.

But it still gets you to the point that in any given hour of the day, Hydro's ability to export is limited by a constraint, and it doesn't have unlimited ability to move power to the times that it wants to move them. They result in somewhat different conclusions, but it does not mean their system is unconstrained.

The basic point would be, first, I think it's important that -- that people understand that there is an entirely different set of considerations that go into Hydro's decision about how much firm power it can commit to; then the decisions that go into how much opportunity power it can export from time to time.

They're entirely different ways of thinking, and they come out of entirely different systems. And there's some level of mixing in that. And I -- I hope in going through this, we can ensure that we have a little bit of clarity on that.

But, in essence, the firm power commitments are the commitments that come out of looking at the type of tables that were handed out earlier today that come from the Power Resource Plan. They look at what Hydro can supply in a drought year, and they consider how much power can it rely on from different sources, and, as a result, how much surplus might it have that it can reliably provide in all years of the forecast. It doesn't get into a question of transmission constraints.

So, in a sense, as long as we are in the world of firm power exports and thinking about what a given load change does to the ability to export firm power, transmission constraints is -- is almost entirely outside that realm of thinking, because it's looking at long-term drought type of situations. In drought type of situations, you don't have -- you don't have heavy loads on the transmission lines.

But that doesn't mean that -- that any constraints, be it transmission or generation, irrelevant. It just means that it -- that it doesn't change the extent to which you are impacting the ability to commit to firm sales.

But as time goes on, having committed to those firms sales, if you've committed to firm sales as a result of change in domestic load -- domestic firm load, it will change your ability to make opportunity sales, because you've now committed to a basic sale. The firm sales come first; opportunity, given the name, only comes after that.

The -- and it only affects the power being sold on the increment on top of firm. And I'll give you example of -- of what I mean. If we're staying in the realm of firm exports, and if we have two (2) scenarios -- one in which we have a given domestic load and one in which that domestic load is reduced by two (2) units -- one on-peak unit and one off-peak unit -- the Power Resource Plan tables will say, You've just freed up two (2) units that you can make as a firm export sale. And it will give the ability to commit to those.

Having committed to those two (2) as a firm export sale, they'll be firm on-peak sales; that's what Hydro makes, firm on-peak sales.

Now you hand that system over to someone who has to operate it and decide how to do opportunity sales. They've just taken a reduction in an on-peak sale unit and reduction off-peak unit and turned them into two (2) units of on-peak commitment.

Whether you're dealing with generation constraints or transmission constraints, you've just increased your commitment on-peak more than you've reduced your load on-peak. And as a result, if you were -- whether you were previously generation constrained or transmission constrained, either way you have less ability to make those opportunity on-peak sales now, because you've created two (2) units of sale in on-peak, where you've only freed up one (1) unit by reduced load. That other unit was freed off in the off-peak. And, as a result, you end up bumping opportunity sales off the system.

Now, it's going to change in every different water flow condition. It's going to change in every different loading condition. And depending on whether it's hot or cold in the US, all -- you can go through graph after graph and look at all the different scenarios. The basic point is that when you work your way through the system, you can't only look at the firm sales and say every unit of additional firm, domestic sales, will translate one-to-one into an increased or decreased ability to make firm export sales. There are other constraints on the system, and that is not always the best linkage for -- for the impact of changes on the power system.

If it is indeed generation that is constraint on your system, most of the time Hydro does not have the same ability to take off-peak sales, hoard the water, and then sell it the next day on-peak, because the generation is already limited off-peak. You can't generate anymore.

And that was just sort of a -- a generic comment in order to try to help deal with the questions about the tie-line constraints.

At the end of the day it raises significant concerns for somebody who is an industrial customer being told that the appropriate -- or that the load that they are impacting is a firm on-peak sales, even though the power they're using is off-peak if -- they don't link well. A firm on-peak sale is a premium product that they're being linked to and is expected to bear the costs of.

So in section B1 we -- we effectively set out this basic point. I will say it has evolved a bit through this Hearing. But at the end of the day, it's really indifferent as to whether we're talking about -- about generation constraint or a transmission constraint, even at the technical level.

Now, this is also dealt with in Hydro's rebuttal evidence at pages 1 to 3. It has a few other points thrown in the middle there that -- that I won't bother to comment on, but I can deal with it if there's questions on it in regards to the reserve capacity and the extent to which -- which the position was planned on dependable and -- and why we're building more tie-lines, if indeed tie-lines are not the constraint.

Just to keep moving, Appendix B2, which is at page B-4, was an ability to deal with the basic assertion about industrial load growth. And Mr. McLaren can go through the -- what we looked at there and what we summarized, and I'll have some comments on Hydro's rebuttal as we go through these last three (3) appendices.

MR. ANDREW MCLAREN: Good afternoon, Mr. Chairman and members of the panel. In this Appendix B2, what we tried to test was the degree to which industrial load growth in the recent past and -- and forecast in the future is a reasonable driver for the need for this -- this rate.

And what we did when we looked at this, we relied in particular on a set of load forecasts that were provided in response to MIPUG/Manitoba Hydro-1-3C.

And what we looked at there was beginning with the 1998 load forecast, we looked at what -- what it showed for industrial -- or -- or I should say for industrial load growth and expectations of loads in 2007/'08. And we found that they actually unfolded very close, very similarly to what was forecasted in that 1998 load forecast.

And so -- so from there we sort of concluded that it would be difficult to say that -- that this load forecast was dramatically different than -- than things that someone -- people at Manitoba Hydro might have expected at some point. If fell within the range of things, of -- of figures that people had talked about in some of these historic load forecasts.

The second thing we looked at was load forecasts in the next nine (9) years, the coming nine (9) years. And -- and we found that -- that there the degree -- the pace of growth also didn't seem to be changing that dramatically from what had been experienced in the recent past.

And we note that in a -- in a -- the newest load forecast that's available -- been made available in this proceeding, those numbers for forecast growth appeared to have declined even further. So the pace of growth, looking in the next nine (9) and ten (10) years, doesn't seem to be dramatically out of line with -- with things that people have experienced in the recent past.

We've also provided some information in this appendix from other jurisdictions. In particularly we looked at -- at British Columbia and -- and Quebec and -- and saw that these aren't jurisdictions that aren't experiencing new customers. There's certainly major new customers reported in Quebec and -- and some large customers locating in British Columbia as well.

What may be different between those jurisdictions is that British Columbia and Hydro Quebec had experienced offsets in their load growth due to declines in the forestry sector, which Manitoba hasn't seen to that degree to date.

(BRIEF PAUSE)

MR. PATRICK BOWMAN: Now, Manitoba Hydro's rebuttal evidence deals with this point at pages

13 to 16, and there is not much more there that probably needs a lot of comment at this point.

Generally, they acknowledge the points that we've made, outside of calling them irrelevant, and -- and go -- basically go on to note that one of the reasons industrial load growth is down is because they've -- this rate has now sufficiently reduced their forecast by -- or has reduced their forecast by causing customers to reconsider plans.

There's one point that probably merits a bit of comment, and it's in regards to them continuing to say that the most energy-intensive loads are forecast to grow at 4.6 percent a year. The definition of "most energy-intensive" isn't necessarily a given. The -- it doesn't mean all customers covered by the rate, presumably. It means some subset of customers covered by the rate.

But I -- I guess I find it hard to reconcile the concept that these customers that are asserted to be very, very price-sensitive are going to grow by a faster-than-normal rate in Manitoba after being imposed a rate of five point five (5.5) cents on them. If they're really that price sensitive, they have options considerably lower than five point five (5.5) cents in other places.

So it's hard to reconcile the idea that they're going to grow fast but that somehow they're mobile or -- or not captive or able to move. That -- that point, I think, is -- is sort of an outstanding concern, looking at the rebuttal evidence.

The other general comment I would make and -- and think I've touched on this earlier, but it's probably comes better out of the documents that are filed by Mr. Peters in his book of documents, that looking to Hydro's load forecast, in many cases the biggest change in the load forecast is not in the sectors they're calling energy-intensive.

The biggest change in the load forecast is in the primary metal sector. And you see that, for example, in the -- the two (2) versions of the load forecast provided in Tab 7:

> "In the '05/'06 version Hydro was forecasting the primary metal sector to drop from 2.3 terawatt hours to 1.7 terawatt hours over the coming ten (10) years."

By the '06/'07 load forecast, they were now expecting the load forecast for primary metals to -- to go from 2.3 terawatt hours to 2.4 terawatt hours. But instead of a managed decline in that sector, we are actually going see them sustain and even grow a bit.

And that swing -- seven (7) -- point seven (.7) terawatt hours -- is -- is really quite material. And it's -- it's lost, in a sense, by looking at the -- just the percentage growth numbers. And so I thought that merited a comment.

MR. ANDREW MCLAREN: The next section of our -- the next section of our Appendix is -- is B3, beginning on page B-8 of the InterGroup evidence. And this is just a couple of pages that addresses the issue of whether industrial growth is occurring in Manitoba due to low electricity rates.

And we looked at two (2) pieces of information, really, to try and test this. The first is a response to PUB/Manitoba Hydro-1-19, which shows some of the revenue that's forecast to be achieved under this rate proposal.

And when we looked at those responses it appeared that most of the revenue, at about two thirds (2/3s) or so, is forecast to come from the petroleur -- petroleum sector, which ordinarily isn't a type of customer you think of as -- as being able to be very price-sensitive, in terms of making location decision.

And by contrast, when we think about the types of customers that -- that ordinarily people do think about as having electricity as a primary determination in their location decisions -- aluminum smelters or the servers -- the server farms people hear about -- we haven't seen any of those locate in Manitoba. And in fact, what we do have available to us indicates that these aren't located in Manitoba, and -- and where in particular these server farms are locating, there are quite a bit of -- of sort of government support and tax incentives that are announced as part of the package that assist in location of those -- those developments in other jurisdictions.

And so that was really our -- all of our comment on -- on that particular topic in this Appendix.

And then turning to Section B4, beginning on page B-10, what we tested here was within the context of a -- of a Cost of Service Study. We tried to model what the impact on bulk power cost are of -- of changes to load growth. And we responded to an Interrogatory from the Board, PUB-Bowman-McLaren-7, which sets out some of the tables that we -- we ran to try and explain this impact.

And -- and what we tried to do, as I say, was -- was show, using the -- the figures we had available from the 2007/'08 Cost of Service Study, what would happen if you added these large loads within the context of bulk power in that Cost of Service Study.

And we have some comments on page B-4 that are worth noting on this analysis. First that, you know, the type of load we're talking about here is an extremely large load for Manitoba. There's very few sorts of customers that would have that -- that level of impact, and it would be kind of an unusual load situation.

We're -- we're also relying on some of the -- the export information and other -- other variable that have been discussed in the context of this -- of this proceeding.

But what we found when we -- when we tried to -- to model this change was that adding this much load, regardless of whether you add it to a residential customer class or an industrial customer class, does have an -- an adverse impact on rates for the other customer classes at the bulk power level.

We -- we weren't trying to deal with distribution costs or any -- anything related to that; we were looking at the bulk power system. And that rate impact was -- for this scale of load, was between about 1 1/2 to 2 percent of an adverse impact, I believe, in that 2007/'08 load forecast -- or Cost of Service Study, excuse me.

MR. PATRICK BOWMAN: Now, just to finish

off on the -- that point, as it's dealt with in Hydro's rebuttal, they deal with our -- our Appendix B-4 at their Sections 16 to 18, pages 16 to 18, and -- and Attachments 2 and 3.

Outside of the challenge of reading Attachments 2 and 3, given the font size in their evidence, the -- I -- I have to say, in a sense, that the tables are a little bit confusing. But I'm quite -- we -- we've been able to work through it. It isn't -- we've now been able to confirm that they're basically tables that Hydro used in the last GRA and are -- and are effectively designed to say residentials pay higher rates than industrials, which is true.

It doesn't change anything in respect of the fact that that point has been made. The -- the purpose of our evidence was to say that if you're only looking on net revenue impacts on Hydro as a whole, you may conclude that a loss of an export kilowatt hour, made up by a domestic hour, that residentials cover more of the cost than industrial. So be it.

It ignores the fact as to what those res -- revenues are designed to pay, but it also ignores the fact that that only occurs when you look at Hydro's bottom line. When you actually look at customer cost impacts, if I'm small business, I'm equally impacted, whether the industrials grows by a kilowatt hour, or whether residential grows by a kilowatt hour, or whether a medium grows by a kilowatt hour, because the way the cost of service flows through, it looks at bulk power costs in total. And every lost kilowatt impacts everybody effectively the same way. It's very -- it's -- it's very balanced in that way.

So we were trying to sort of bring out that extra aspect that I don't think was -- was clear in -- in Hydro's evidence.

Attachments 2 and 3 that Hydro put to its evidence, just so that people understand, are tables done using Hydro's approach to marginal costs. As -- as I said, they're effectively tables used in the same GRA, to the point that they contain the same math error that we pointed out in the last hearing, and they are not the way that utilities use marginal costs.

We -- we discussed in the last hearing that there's something like three (3) utilities that use marginal cost to set there rates; one of them is San Diego Gas and Electric in California, who we -- we had gone off to talk to and made sure that we understood how they did marginal costs. And it's not in this way; it's by function.

So I think in terms of these tables, I

don't have much more comment than we had the last time.

The -- there's one point though that merited making at this stage. In hearings of this type, there are occasionally words that take on different meanings and that are a little bit loaded. One of those is the word "subsidy." And when people use the word "subsidy," they can mean very different things.

One way that that term is used is by looking at something like the Cost of Service Study and saying that when you assign every class a -- a fair share of embedded costs, that because the export revenues pay more than their embedded costs, and those export revenues are funnelled back to other classes, everyone's receiving a subsidy from the export revenues. It's -- the term is -- is occasionally used that way, and it's said in many hearings over the years that as a result, no class is paying its embedded costs.

I just want to make sure that we're -- we're clear that as of this last rate change, that is no longer true for all of the classes. Industrial customers at this point, even before they receive a nickel of that export revenue, are now covering more than their embedded costs.

That -- the table in -- that Mr. Peters used in his -- in his book of documents that summarize the PCOSS results have the costs to industrial customers at three point two (3.2) cents, and the rates are about three point three (3.3). And that's before you credit any of the export -- the next export revenues.

So at least as that term, "subsidized" is used, sometimes it's used by comparison to short-term marginal costs; sometimes it's used in comparison to long-term marginal costs. At least it's used with respect to embedded costs.

It is not true that each class is -- is subsidized by exports. In an embedded cost jurisdiction, that wouldn't be the measure the discuss subsidization. But I thought it was important to -- to clarify that for the record.

Now, just in terms of finishing up, there is an Appendix B5 in our submission. It was put there because we were trying to understand the revenue forecast from this rate.

We were able to reconcile the numbers, or at least figure out where the mathematics came for the numbers. and it -- this -- this is a response to Coalition/MH-1, Round 1, Question 8C, indicates that the revenue from this rate would grow from about 20 million to about 25 million a year, according to the IFF -- through the IFF horizon, the ten (10) year horizon that's in the -- Hydro's integrated financial forecast.

We were able to derive that number by looking at the fact that today, the -- this rate would be a two point three eight (2.38) cent per kilowatt hour premium over the standard rate, and then multiplying that two point three eight (2.38) cent per kilowatt hour rate times the volume of above-baseline sales.

But the -- the two point three eight (2.38) cent rate is locked in through the entire period in that -- in that type of forecast number. If you actually look at Hydro's forecast of -- of export revenues, they actually show quite a bit of growth from the levels that are based on the -- the latest measures, in part because the Canadian dollar is thought to recede from the levels that were in there in the firm numbers that were recently recorded and in part, due to escalations in the market.

And it's well above the pace of escalation of the standard rates in Manitoba, such that by the end of that period, it -- it's possible to -- that that premium may not be two point four (2.4) cents anymore; it may be up as high as five point eight (5.8) cents.

And, as a result, the forecast revenues that are put in there probably significantly understate what could arise, even if that same level of sales arise that Hydro has put in.

The second factor is, of course, that Hydro's load forecast includes only known plans of customers. It doesn't include notable new customers, not that we get many. I think we've gotten one new GS Large greater than 100 kV in ten (10) years. But it doesn't include any provision for notable, at least new -- new, customers or -- or any -- on -- as yet unplanned expansions at -- at any of the existing customers.

Some of us who are Manitoba optimists may like to think that that's maybe not -- doesn't pick up the full range of people who might actually pay this rate if -- if it were approved.

The -- I -- I didn't go through our Appendix A. It's -- it's there for review. Hydro deals with it and their rebuttal at page 18. But it's -- it's merely a couple of comments that if someone was to do a rate of this type and determine that -- that this was necessary, that there's a few items in Hydro's proposal that probably could be improved upon. Some of them will be commented on tomorrow by the MIPUG presenters, I understand.

In large part, Hydro's rebuttal evidence deals with our Appendix B, the basic facts of the case, as opposed to the overall proposal that's there. The exception is their rebuttal evidence starting at page 9, where they go into the point about, is the proposed rate unduly discriminatory.

And I think we have dealt with most of the points that are there. There's a piece in there about industrial loads causing Wuskwatim to be needed for domestic purposes, and the -- I think I dealt with that in the -- in the section on the overall Power Resource Plan.

There's some comment on the Order in Council that exists that permit -- allows Hydro to export power, which says that the power must be surplus to Manitoba's needs. It -- the Order in Council says what it says. It would be worth considering whether this is a means to redefine surplus by effectively making domestic customers be prepared to bid against exports to determine if they want the power; otherwise it becomes surplus.

And then there's particularly the -- the one that I wanted to comment on at page 11, and I believe I addressed this before lunch. But if not, let me just touch on -- on this point. Hydro says at line -- line 5 of page 11 of the rebuttal:

> "The evidence of Bowman and McLaren itself recognizes that some form of discrimination may be appropriate to

provide protection to other
ratepayers."

And they go on to use our discussion of BC and Quebec in order to set out why they say that we are recognizing discrimination as appropriate.

I just wanted to make sure that the record is clear. In our view, neither the BC rate -- rate supplement-- tariff supplement 6 or the Quebec rates that are put in place by government policy would be what one would describe as discriminatory. It's not even a question of are they duly or unduly discriminatory. They wouldn't be things that would lead you to even say they're discriminatory within the context of our -- of our regulatory arena.

And I -- I may have touched on the reasoning before, but -- but basically it -- it relates to the fact that in BC tariff supplement 6 says you need to look further and further upstream to understand a customer's impacts on this system as they get bigger and bigger.

But you're still using the same principle, whether you're dealing with a homeowner or a large industry. You're still looking to make sure that the system reinforcements occur necessary to supply that customer's load. You're applying the same principle, just a different implementation.

And in Quebec the decision to limit the obligation to serve to 50 megawatts and take rates for customers above 50 megawatts out of the regulated jurisdiction is a decision by government.

And I think I may have touched on this before. The decision as to whether a rate is discriminatory or unduly discriminatory in a regulatory arena occurs within the bounds set out by the government's policy and legislation. That type of decision is outside of the arena. It's not something that's debated before a Board. It just exists. It's part of the framework we all have to deal with.

Uniform rates would be a similar example in Manitoba. It's not a question as to whether it's discriminatory or nondiscriminatory in a regulatory arena. It's just a function of -- of the -- the framework that we're assessing in this room, and that's because it's imposed by legislation.

Now, just to sum up, by the time we were done going through the matters noted -- and this is set out -- our overall conclusion at page 7 of our evidence.

It was the conclusion of the InterGroup submission that the rate as proposed by Hydro compromises basic regulatory fairness principles.

That the proposal is unusual, to say the least, in a regulatory framework and -- and would require a -- quite an unprecedented action by this Board to approve something that is quite clearly discriminatory.

That there's -- Hydro's evidence doesn't provide a reasonable or sufficient justification for that level of -- of action or decision by this Board, in our submission.

And that if indeed the concern is about dealing with the system impacts of large new customers, there are established ways to deal with it. Something like tariff supplement 6 in British Columbia helps ensure that the capital costs for capacity-related abilities to supply customers, transmission, or in some cases things like thermal generation, are -- are dealt with.

Once the system, though, is put in place, to be able to supply the capacity that's needed, the -- there's no basis in -- in the proposal that or in established regulatory precedent to consider one set of kilowatt hours different than another set, in terms of the principles applied to them as to which -- which effectively gets service and in better rates and which don't qualify for service.

And so in that regard we would say that Hydro's proposal should be denied.

That -- that would sum up the direct evidence.

MR. JOHN LANDRY: And, Mr. Chair, I have no further questions, so the panel is subject to your direction.

THE CHAIRPERSON: Okay, thank you, the panel and Mr. Landry. So we will begin now with Mr. Williams.

Mr. Williams...?

CROSS-EXAMINATION BY MR. BYRON WILLIAMS:

MR. BYRON WILLIAMS: Thank you. Good afternoon, Mr. Chairman and members of the Board. I think in the second row, by the water cooler, Ms. Desorcy is back for a -- for a taste of the regulatory experience.

And I certainly want to welcome you, Mr. Ostergaard, as -- and welcome you back, Mr. Bowman and Mr. McLaren.

Just for the -- the panel's benefit, the -- in the next, probably, half an hour or so I'll -- I'll be going through a bit of the evidence, both primarily of Mr. Ostergaard, but also some of Mr. Bowman. So those two (2) pieces -- Mr. Bowman and Mr. McLaren -- so those two (2) pieced of evidence you may wish to have at hand.

And we're not going to start quite there, but if you're looking for a page to turn to, page 20 of Mr. Ostergaard's evidence would be a good place to start.

Mr. Ostergaard, you -- I know Mr. Landry went through your qualifications to some degree. But you are here bringing the benefit to the Board, both your experience within the -- the government as an Assistant Deputy Minister in electricity and alternative energy, as well as -- as a -- the Chair and Chief Executive Officer in the past of the BCUC.

Is that right, sir?

MR. PETER OSTERGAARD: That's correct.

MR. BYRON WILLIAMS: So you bring experience both from -- from the government policy perspective as well as from the -- the regulatory perspective, and in your business -- your consulting work also from the -- the real world, practical perspective of business as well, sir.

Is that right?

MR. PETER OSTERGAARD: I think that's a fair comment, yes.

MR. BYRON WILLIAMS: And you don't need to turn there, but just in -- in general terms, you take the position that in any jurisdiction, electricity pricing for new and existing customers is a significant policy and regulatory matter which potentially effects economic prosperity and development.

Would that be a fair statement, sir?

MR. PETER OSTERGAARD: Yes, I recall that is in my evidence.

MR. BYRON WILLIAMS: And that's your -- that's -- that's the position you take? It's an important matter?

MR. PETER OSTERGAARD: It is.

MR. BYRON WILLIAMS: And I just want to draw your attention to -- if you go to page 20, lines 24 to 27, and if you'll permit me, I'll -- I'll read this in. You comment that BC Hydro was created by a government that considered large-scale hydro development as a pro -- prerequisite to the economic development of British Columbia's interior and North, and the role of BC Hydro in stimulating the provincial economy has been an implicit policy of all subsequent administrations.

That's your position, sir?

MR. PETER OSTERGAARD: Yes, it is.

MR. BYRON WILLIAMS: And just in terms of the -- the last part of that sentence, starting on -- on line 26, I wonder if you can outline what you understand to be government -- the -- the conception of government, in terms of the role of BC Hydro in stimulating the provincial economy.

What role has it played?

MR. PETER OSTERGAARD: Certainly, when BC Hydro was created in the 1960/1961 period, it was a large construction company.

BC Hydro was responsible for developing, I believe it was, six (6) major projects on the Peace and Columbia Rivers. They were the entity to implement the Columbia River Treaty. They were largely responsible for electrifying the northern part of the province, as well as the interior. The pulp and paper industry, the mining industry in the interior of the province was developed as part of the vision of the premier of the day, W.A.C. Bennett to "open up," in quotation marks, the North. And, in fact, that's precisely what happened in the 1960 and '70s.

By the 1980s, as my evidence suggests, BC Hydro was in an overbuilt situation. The -- as I mentioned this morning, the Revelstoke projects -- the 1,980 megawatts, which came on stream in 1984/'85 -- was entirely surplussed to domestic needs.

Therefore, BC Hydro had to reinvent itself. And to do that, it became a management and operation company to try to keep rates reasonable; to reduce its debt so that residential, commercial, and industrial customers could continue to enjoy low rates across the province with a continuing obligation to serve all new customers, whether commercial, residential, or industrial, at the same rates as those that were being paid by existing customers.

MR. BYRON WILLIAMS: And I won't dwell on this. But in the -- in the '60s and '70s, just as I understand it, two (2) key roles that built, one was -- well, let's do with the first one. One was in terms of the -- just the capital-intensive nature of its -- its construction, certainly a fiscal stimulus to the province.

Is that fair?

MR. PETER OSTERGAARD: Absolutely. You can correlate Hydro expenditures with GDP in the province quite closely.

MR. BYRON WILLIAMS: Secondly, just opening up major areas of the interior and the North to what was -- were considered to be important economic developments, whether those are pulp and paper or other.

Would that be fair? Mining.

MR. PETER OSTERGAARD: Yes.

MR. BYRON WILLIAMS: Now, the second stage that -- that you've discussed, that goes from the 1980s. Does it -- and I'm presuming to -- until today.

That's focussed on keeping rates at a -- I think you used the language "relatively low level."

And -- and can you focus in on -- on how that serves as a -- an economic stimulus, in terms of the -- or within the province?

MR. PETER OSTERGAARD: Certainly. British Columbia, as our industrial customers tell us, is a not exactly a low-cost jurisdiction in which to -- to mine, to mill, to cut trees, and to engage in other industrial pursuits.

The one advantage, in their view -- and I agree with them -- that British Columbia has over all others is reliable electricity supply at a reasonable price. For example, since the early '90s, BC Hydro rates were largely unchanged for ten (10) years. The rates were frozen until about 2003, I believe it was; could have been 2002.

When a new government came in, they continued the rate freeze for another year or two (2) to come up with a new energy plan.

One of the most significant events, in my view, that took place in the last several years, with respect to BC Hydro's rates and the policies that help form them, was the recommendation of the task force that had been appointed by the new elected Premier in 19 -- in

2001. That task force, which was headed by the Deputy Minister of Energy, recommended that BC move towards market rates, and that recommendation was very controversial. It was front-page news. Customer groups got quite involved.

And at the end of the day, the 2002 Energy Plan said, No, we are not going to market rates; instead, we will be sending price signals on the margin, first for industrial customers, by having a stepped rate.

MR. BYRON WILLIAMS: And I'm going to, in a -- in a few minutes -- hopefully before the day's over -- come back to that decision in 2002. But I want to stay on the -- the economic stimulus just for a few more moments.

And perhaps you can turn to page 35 of your evidence, which is probably Appendix B.

(BRIEF PAUSE)

MR. BYRON WILLIAMS: Do you have that, sir?

MR. PETER OSTERGAARD: That's the one that has twenty-three (23) lines on it?

MR. BYRON WILLIAMS: Indeed. And just before we got to the -- the move to -- or the suggested move to market rates, you were talking -- as I understand it, just to summarize, notwithstanding the fact that BC has a number of disadvantages economically, in terms of not making it a low-cost jurisdiction, its one competitive advantage, I understood you to say, is its reliable electricity at a -- at a reasonable prices.

Is that fair, sir?

MR. PETER OSTERGAARD: Yes.

MR. BYRON WILLIAMS: And just to perhaps underline that point, I'll direct your attention to lines 18 to 23 of your -- your evidence here.

And you state -- and I'll ask you to confirm this -- that new BC Hydro customers continue to benefit from the availability of the heritage contract energy and from favourable transmission and distribution extension policies. This has given British Columbia industrial and commercial businesses a competitive vantage and has been instrumental in many organizations' decisions to locate or expand facilities in the province.

That's your position, sir?

MR. PETER OSTERGAARD: Yes, it is.

MR. BYRON WILLIAMS: And I believe you noted this in your direct this morning, but you were quoting from the -- what I believe was the BC Energy Policy from 2007.

And again, you don't need to go there, sir, but you again used -- it's described as a -- BC Hydro has a competitive advantage in that -- in that paper as well, sir?

MR. PETER OSTERGAARD: Yes, it is.

MR. BYRON WILLIAMS: Just drawing your attention and focussing on your assertion that the -- the availability of heritage contract energy has been instrumental in many organizations' decisions to locate or expand facilities in the province, I wonder if you can give myself and my clients one (1) or two (2) practical, living examples of -- of what you -- supporting this statement, and -- and just at a high level, if -- I'll try and add a broad -- ask a broad question.

Explain the nature of the expansion, how you believe Hydro was instrumental in bringing about that expansion, and why you consider that to be of a net benefit.

Did you get that multi -- multifaceted question, sir?

The three (3) points were: the nature of the expansion; how Hydro was instrumental in that decision; and why you consider that to be of net benefit.

Can you help me with an example or two (2), sir?

MR. PETER OSTERGAARD: I guess the one example that comes to mind from my evidence was the largest industrial expansion in BC, in terms of megawatt addition, namely the electrification of new pumping stations for the Kinder Morgan pipeline that takes crude oil from Alberta, the Edmonton area, through the lower mainland and drops them off there and continues on to Puget Sound.

That is part of North America's oil supply system, and it has allowed the oil expansion in Western Canada to expand westward instead of sending it east. And BC Hydro was instrumental in that decision, from my understanding, by the -- by the existence of tariff supplement Number 6, where the contributions, as are described in the evidence set out.

The -- the net benefit, as I mentioned, could be attributed to keeping -- from a gasoline consumer's perspective on -- in Southwestern British Columbia traditionally we are short of gasoline, which is what -- one -- one thing that the -- the gasoline retailers say is a reason for higher prices in West -- West Coast than in other parts of the -- other parts of the continent. So if we can get more refined product to the West Coast through an expanded pipeline, then everybody benefits.

Another example, which I reference in the evidence, is the strong interest in developing new mines in Northwestern British Columbia. There's a strong desire on the part of the regional economy north of Terrace, north of Prince Rupert, along Highway 37, to diversify the area of -- of Kitimat to Terrace. And Prince Rupert is arguably suffering economically more than other regions in British Columbia. And there is a strong desire on the part of most residents of the Northwest to diversify their economy.

And putting a transmission line up Highway 37 to serve, first of all, NovaGold Mine, and possibly other mines in future, would be very strongly supported by residents of Northwestern British Columbia.

MR. BYRON WILLIAMS: Thank you. And it was a broad question which invited a broad answer, and I -- I thank you for that.

Just in terms of what -- what you and the -- the British Columbia Government des -- describe as BC's competitive advantage, just for shorthand purposes, I'm going to refer to it as the -- the BC advantage.

Is that fair enough, sir?

MR. PETER OSTERGAARD: Yes, that's a slogan that is in use in British Columbia.

MR. BYRON WILLIAMS: Do I owe any

copyright fees for that, sir?

MR. PETER OSTERGAARD: You'll have to check with -- with the government's communication's department.

MR. BYRON WILLIAMS: Perhaps I have a future there.

Just in -- and -- and Mr. Bowman spoke of this, and I'm not ref -- I'm still sticking with you, Mr. Ostergaard. But -- but he seemed to -- to be making the point that selling at embedded costs, or -- or some version of that, from an economic developed -- development perspective, allowed one to, rather than just sell products, raw materials, to consider the -- develop the opportunity to add value to them in -- in additional industrial processes.

Is that a view that you share, sir?

MR. PETER OSTERGAARD: Yes, I do.

MR. BYRON WILLIAMS: So when you speak of the BC advantage, which I understood is copyrighted by government communications people, it's an ability to use the hydroelectric bounty that -- that nature has given British Columbia as a tool to attract and -- and retain development that either diversifies the economy or adds value to the economy.

Is that fair, sir?

MR. PETER OSTERGAARD: Without getting into the -- the slogan too mar -- too far, the BC advantage covers more than simply electricity. It in -- or it includes things like lifestyle, healthy climate most of the time, strong quality of life, clean air, clean water, et cetera, and the economic benefits that lead to a higher quality of life, secure, reliable electricity supply, energy, healthcare, et cetera.

MR. BYRON WILLIAMS: And I'll --

MR. PETER OSTERGAARD: Electricity is one component.

MR. BYRON WILLIAMS: And I'll come back in -- in a couple moments, perhaps, to how, if at all, electricity may -- may contribute to lifestyle as well. I'm not sure if that's part of your -- the BC advantage or not.

You'll agree with me though, Mr. Ostergaard, that an alternative to using heritage rates as a mechanism to achieve a competitive advantage is instead to price all usage, or a significant proportion of existing usage, at market rates.

That's a different way of -- of looking at a way to take advantage of bountiful hydroelectricity, correct, sir?

MR. PETER OSTERGAARD: Yes.

MR. BYRON WILLIAMS: And you were in the Hearing, I -- I believe, for -- for much of yesterday.

Is that right, sir?

MR. PETER OSTERGAARD: For much of it, yes.

MR. BYRON WILLIAMS: And you may have heard Mr. Chernick argue that even if a move to market rates for some portion of existing usage or -- resulted in a decrease in production, if it can now -- if a company reduces production when the cost of a subsidized input is raised to the market value, the effect is a net benefit.

Do -- do you recall a discussion on that point, sir?

MR. PETER OSTERGAARD: I vaguely recall it; but I must admit, I was not listening closely.

MR. BYRON WILLIAMS: And that's fair enough. But you've -- you've agreed that an alternative to the -- to the competitive advantage of -- of hydro from -- as a method to add value-added is to -- to move to a predominantly market-based approach.

We've -- you -- that's what we've agreed on already, sir?

MR. PETER OSTERGAARD: The alternative to a cost-based embedded cost structure -- which Manitoba, British Columbia, and most of Quebec currently enjoy -- is to develop some sort of alternative market mechanism, which inevitably involves pricing the product on a market bases as opposed to a cost of production, a cost-of-service basis.

MR. BYRON WILLIAMS: And I'm not asking you to advocate for -- for that kind of perception, obviously. But I'm going to suggest to you that presumably the thinking behind that would be that BC could us hydro like Alberta uses oil -- kind of a black gold, selling it for market rates, and while simultaneously promoting energy efficiency and -- and conservation.

Is that what you understand to be the think be -- behind that alternative point of view, sir?

MR. PETER OSTERGAARD: Generally, yes; that's an intriguing analogy.

MR. BYRON WILLIAMS: Staying on the same point, but moving slightly to the -- to the right or left, I'm not sure which, are -- are you familiar with -- at a high level, with the school of thinking, Canadian economic nationalism that -- that criticizes certain -- certain development approaches as kind of relegating Canada to merely being hewers of wood and drawers of water.

Does that ring a bell at all, sir?

MR. PETER OSTERGAARD: Yes, it does. It's been an argument that's been going on in economic -- economic geography/international relations circles for as long as I remember.

MR. BYRON WILLIAMS: And is -- and you may or may not agree with this characterization, but as compared to the -- the BC advantage or the competitive advantage, would you see that moving to a -- a predominantly market-based system as being more representative of that traditional thinking, kind of hewers of wood, drawers of water, sir?

MR. PETER OSTERGAARD: I don't think so, and I'll use the example of pellet plants. Pellet plants are -- I shouldn't use the -- the term springing up all over the province. But to my knowledge there's at least five (5) or six (6) wood pellet plants that are either under construction or in operation using mountain pine beetle killed wood to process and manufacture pellets, most of which go to Western European markets for thermal electricity generation.

Electricity is a strong component of an input to those plants. If those plants had been developed with higher, market based electricity rates, arguably the bug-killed wood could have gone to Europe on the stump -- not on the stump, off the stump, thrown into boats, and turned into pellets in another jurisdiction.

So electricity rates, I think, are fundamental in encouraging a biomass industry in British Columbia, which does include wood pellet manufacturing.

MR. BYRON WILLIAMS: Thank you for that. And just to turn you to your evidence to page 30; and that's still Attachment B, I believe.

Do you have that, sir?

MR. PETER OSTERGAARD: Yes, page 30, Attachment C.

MR. BYRON WILLIAMS: My mistake. And just -- and you talked earlier about the -- the energy task -- the task force on energy policy in British Columbia. And I want to focus on the 2002 task force on -- on energy policy.

I understand it made a number of recommendations to the BC government, many of which were implemented in the 2002 BC Energy Plan, sir.

And that's focussing your attention on -- on the bottom, kind of, from page -- lines 26 to 38 of your -- of your -- of page 30, sir.

MR. PETER OSTERGAARD: Yes, that's correct. In the 2002 Energy Plan, Appendix 1 is titled, "Comparison of Energy Policy Task Force Recommendations with Energy for Our Future, A Plan for BC," which is the name of the energy plan.

MR. BYRON WILLIAMS: And you just indicated to me before that although -- or I'm going to suggest to you that although the energy -- energy plan adopted many of the recommendations of the task force, two (2) which it rejected -- and I'm referring you to line 34, sir, of your evidence, if that will help you -- were the recommendations to create a wholesale elect -- electricity market in BC and -- and the recommendation to move to market pricing over ten (10) years.

Is that right, sir?

MR. PETER OSTERGAARD: Yes, that's correct.

MR. BYRON WILLIAMS: And in your discussion with me earlier today, you -- you suggested that this was very controversial and made the headlines in 2002.

Is that right, sir?

MR. PETER OSTERGAARD: Yes, it did. It was very publically -- had a high public profile amongst the labour movement, amongst electricity consumers, not just industrial customers. I recall at the time that California, Oregon, and Washington had just gone through a -- an electricity crisis, and that was also very much in the public mind on the West Coast.

MR. BYRON WILLIAMS: And thank you for that. And just in your evidence at lines 37 to 38 you -- you note that the recommendations had been opposed by BC Hydro -- Hydro customer groups and the -- and the general public, correct?

MR. PETER OSTERGAARD: Yes, that's correct.

MR. BYRON WILLIAMS: And in terms of customer groups, you mean not just industrials.

Would you -- were residential customers -- was there some sense that they were opposed to this as well, sir?

MR. PETER OSTERGAARD: I can't recall exactly in my own mind if I ever saw a letter, for example, from a consumer representative group. However, I am certain that the industrial customers, through the Joint Industry Electricity Steering Committee, were very public in their opposition to that recommendation, as were labour organizations.

MR. BYRON WILLIAMS: Just at a high level, can you summarize your understanding of why industrials, first of all, were -- were opposed to that -- that sort of direction?

MR. PETER OSTERGAARD: Industrials were

seeing what was happening to their counterparts in Ontario, Alberta, California, and other jurisdictions that had reformed their electricity markets in such a way that cost of service based, monopoly based pricing was being changed to unbased on market rates.

And in their view, based on their experience, electricity rates in those jurisdictions were rising very, very quickly, relative to jurisdictions that continued with cost-of-service-based rates, including British Columbia.

MR. BYRON WILLIAMS: And from the perspective of labour -- labour unions, can you -- your understanding of their objection, sir?

MR. PETER OSTERGAARD: My understanding of the objectives -- objections of the -- of the labour movement in British Columbia were the fear that BC Hydro would be broken up and privatized, and -- and, therefore, unions may be decert -- decertified in the process.

At the time also, BC Hydro was contracting out much of its backroom billing service to a company called Accenture. That was also very controversial.

MR. BYRON WILLIAMS: And without getting too much into the -- more into the BC advantage, we -- we primarily talked about the hydroelectric competitive advantage as applying to industrials.

How, if at all -- well, first of all, my understanding is that heritage rates were also available to residential customers, sir?

MR. PETER OSTERGAARD: The heritage contract defined in law is available to all customers in British Columbia.

MR. BYRON WILLIAMS: From a policy perspective, what's the thinking behind making it available to -- to residential, sir?

MR. PETER OSTERGAARD: All customer groups are entitled to share in the benefits of the investments made in the '60s and '70s in BC Hydro's electricity generation system.

MR. BYRON WILLIAMS: Now, just taking largely off -- well, taking off a bit of your ADM hat and putting on more your BCUC hat, at a very high level, my understanding is that the -- is that the BCUC operates as an independent exter -- expert tribunal in setting rates for certain rates in British Columbia, including hydroelectricity rates.

Is that fair, sir?

MR. PETER OSTERGAARD: That's fair. But in anticipation of the possible next question, through most of the 1990s, through my term at the BCUC, BC Hydro rates were first capped and then frozen by legislation.

So I was not personally involved in significant rate decisions on the part of the BCUC.

MR. BYRON WILLIAMS: I'll have to research where that question could have led me. I wasn't -- I wasn't heading there. I'm just -- so don't worry.

But you spoke in direct evidence today about a fair degree of interaction between the government, in terms of setting policy, and the BCUC, in terms of implementing that policy.

Do you recall that, sir?

MR. PETER OSTERGAARD: Yes, I do.

MR. BYRON WILLIAMS: And I don't know if the -- this argument extends to Manitoba, but I think the language you use is:

> "Uneasy is the head of he who regulates the Crowns in British Columbia."

Is that the language you use, sir?

MR. PETER OSTERGAARD: That was a comment that was made by one of my predecessors at the BCUC, and it's fairly well-known throughout the regulatory community in British Columbia.

MR. BYRON WILLIAMS: Where I'm going with this, sir, is you've talked about in the -- since the 1990s, I believe, four (4) different energy plants for British Columbia set out by the provincial government, sir?

MR. PETER OSTERGAARD: Perhaps I can take the opportunity to correct a -- a mistake I made this morning.

Early in my direct evidence, I -- I noted that BC governments had issued four (4) energy plans. I stated the first was from 1990. Actually, the second was from 1990; the first was from 1980. So the first plan was issued in 1980, the second in 1990, the third in 2002, and the fourth in 2007.

Thank you for the opportunity to correct myself.

MR. BYRON WILLIAMS: That's fine, and no problem.

And, again, without going to it, but the -- the 2002 Energy Plan, for example, entrenched the -- if you're looking for a reference, sir, it's probably at page 31 of your evidence. It entrenched the -- the heritage contract and also suggested that -- made a commitment that BC Hydro ratepayers were to continue to benefit from electricity trade.

Is that fair, sir?

MR. PETER OSTERGAARD: Yes, that's correct.

MR. BYRON WILLIAMS: What I'm hoping for

some guidance from you for is some sense of how these energy plans interact and how they're -- how they guide the deliberations of the regulator in British Columbia.

MR. PETER OSTERGAARD: The regulator, first of all, reads the plans. The regulator may ask government for clarification. In the case of the heritage contract, the government asked the BCUC to define what is, essentially, a one (1) paragraph policy statement in the plan and also articulate it, come up with draft legislation and special directions that the government could consider.

And in the case of the legislated heritage contracts, the commission did -- was indeed requested by Cabinet to develop recommendations on the heritage contract and regarding stepped rates and transmission access.

So two (2) of the key recomme -- or two (2) of the key policies, rather, in the 2002 plan were expanded upon, developed by a BCUC process -- which was very public, lots of input by interested stakeholders.

They submitted their report and recommendations to Cabinet; Cabinet accepted almost all of the recommendations with respect to both the way the heritage contract should be structured and the stepped rates should be structured.

MR. BYRON WILLIAMS: From your direct evidence this morning, sir, and recognizing that you're not particularly familiar with -- with Manitoba, but the -- the inference that I drew was that there's a more intensive interaction between the BC government -- at least your -- your observation was, on a preliminary basis, that there is a more intensive interaction between the BC government and the BCUC, as compared to what you've observed between the province and the regulator in Manitoba.

Would that be a fair statement, sir?

MR. PETER OSTERGAARD: I think that's fair, without knowing fully how the Public Utilities Board in Manitoba reacts or relates to the Minister of Energy or -- or the Lieutenant Governor and -- or counsel or Cabinet.

Suffice it to say that in British Columbia there's a variety of ways that the BC Utilities Commission is limited, guided -- whatever word you would like to use -- by the government, including legislation, including special directions under the Utilities Commission Act, including Ministers' Exemption Orders under the Utilities Commission Act, and through special directives to BC Hydro, to which BCUC must -- must abide.

MR. BYRON WILLIAMS: I'm going to come in a second to how that intensified interaction might be a good thing.

But before I do that, as someone who has worn both hats, do you have any concern in -- in terms of the -- the perception that a model such as that might create in terms of the independence of the regulator, sir?

MR. PETER OSTERGAARD: There's always a balance between the independence of an administrative tribunal and the desires of its -- of -- of the people who appoint it.

In the case of British Columbia, I've seen some jurisdictions that have left the Utilities Commission to its own devices. At times, the Utilities Commission would have liked to have had some guidance on some issues and didn't get it from government?

The other extreme is the concern that the Commission is being severely limited in its ability to review things that other -- otherwise would have wanted to.

An example coming to mind is the situation where BC Hydro's rates had been capped by legislation. BC Hydro was over-earning. They were making a lot of money in the export market. Customer groups came to the Commission and said: BC Hydro is over earning. Rates are capped but you can still lower them.

The out -- the upshot of that particular situation was the government responded with legislation that froze rates, instead of just capping them.

So, yes, there are certainly situations where arguably the Utility's ability to have a free hand in regulating the Utility may be limited by government, because government sometimes has different reasons, in terms of public interest, than the Commission does with -- which -- of course, it has its ratepayers and shareholders of utilities' interests at heart.

MR. BYRON WILLIAMS: Just moving to Manitoba, you'll -- you'll agree in this proceeding, we're dealing with -- collectively, with a variety of complex questions including the appropriate role for pricing based upon embedded costs versus market costs?

Those are complex issues, sir? That's a complex issue?

MR. PETER OSTERGAARD: Yes, it is.

MR. BYRON WILLIAMS: You'll also agree that there's also complex issues associated with the -- the appropriate role, if any, that Manitoba Hydro should play in -- in promoting economic growth and development through its rates in this province?

That's -- that's a complex issue that's --

that's before us, at least to some degree, sir?

MR. PETER OSTERGAARD: I would agree with that statement as well.

MR. BYRON WILLIAMS: If you were taking off your consultant hat and back on, kind of the -- sitting as a regulator in a proceeding such as this, sir, would you have any discomfort in addressing some of these questions without guidance -- expressed guidance from -- from the province?

MR. PETER OSTERGAARD: I guess one's views on these issues are shaped by one -- one's experiences and my experiences in British Columbia would have been that I would have received guidance as a regulator from governments on how these important issues should be handled.

MR. BYRON WILLIAMS: And as a regulator, can you -- can see how some sense of provincial direction in these areas might -- might be of assistance in fulfilling one's duties?

MR. PETER OSTERGAARD: Yes, I believe provincial assistance would be helpful.

MR. BYRON WILLIAMS: Mr. Chairman, I've kind of come to a convenient break. Noting with pleasure that I actually kept to my deadlines yesterday, I think I can advise you that I'll certainly be less than an hour tomorrow. And I may mean at about forty-eight (48) minutes or so, sir.

THE CHAIRPERSON: Very good, Mr. Williams. We are not going to time you though.

MR. ROBERT MAYER: Pardon?

THE CHAIRPERSON: The Vice-Chair may time you.

MR. BYRON WILLIAMS: I believe -- I believe Mr. Cathcart does and I suspect perhaps one (1) panel member may, as well, sir.

THE CHAIRPERSON: Okay. Well, we will stand down. We will see you all tomorrow morning at 9:00. Thank you.

(MIPUG PANEL RETIRES)

--- Upon adjourning at 3:54 p.m.

Certified correct,

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Cheryl Lavigne, Ms.