MANITOBA PUBLIC UTILITIES BOARD

Re: CENTRA GAS MANITOBA INC.
2005/06 TO 2006/07
GENERAL RATE APPLICATION

Before Board Panel:
Graham Lane - Board Chairman
Monica Girouard - Board Member
Mario Santos - Board Member

HELD AT:
Public Utilities Board
400, 330 Portage Avenue
Winnipeg, Manitoba
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APPEARANCES

R.F. Peters		)Board Counsel
Marla Murphy		)Manitoba Hydro
Karen Melnychuk		)Direct Energy Marketing
David Brown	(np)	)Limited/Municipal Gas
Nola Ruzycki		)Energy Saving (Manitoba)
		)Corp.
Kris Saxberg		)CAC/MSOS
Peter Miller	(np)	)TREE and Resource
Randall McQuaker	(np)	)Conservation Manitoba
Sandy Boyd		)CEPU

TABLE OF CONTENTS

LIST OF EXHIBITS

LIST OF UNDERTAKINGS

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

THE CHAIRPERSON: Good morning everyone. I hope you've had a restful evening.

Mr. Peters, I note that you've been busy. Do you have some comments with respect to scheduling?

MR. BOB PETERS: I do indeed Mr. Chairman and Board Members. And let me start off by saying this is coming to the Board Members and the Panel as a proposal and we recognize, we being the parties present in this room, who are trying to provide you with the information you'll need to make your decisions have met and talked about the schedule and the witnesses that are still to be put before you.

When the pre-hearing conference was held the Board contemplated sitting three (3) days this week, three (3) days next week and three (3) days the following week. That schedule has been altered slightly with tomorrow will not be a sitting day of this Board, so that other matters related to Board decisions can be dealt with in other forums.

Having said that we are confident that the Cost of Gas Panel will finish before you today. And I suspect will be a half a day today and I'm not going to make any promises for My Friends opposite, but, I think is where we're going to be sitting.

Then starting next Monday, the 6th of June, the Revenue Requirement Panel would come on and will take the better part of the Monday, Tuesday, Wednesday of that week and that's what's envisioned.

If for any reason that Panel will finish early there may or may not be an opportunity to bring the Cost Allocation Panel forward to utilize some of the time that's available on the Wednesday. But, right now we're planning that next week will be the Revenue Requirement Panel.

The following week, starting on the 13th of June would be the day that the witness for CAC/MSOS Mr. Greg Matwichuk would come to Winnipeg and testify. And we've set aside the 13th to provide certainty of that date for that witness to attend.

Then the 14th and 15th of that week, which are the Tuesday and Wednesday, we would continue with the Centra Panel which would be at that point would be the Cost Allocation and Rate Design Panel, also dealing with a number of Board directives, and so that's the third Panel would take up the Tuesday and the Wednesday of that week.

We then are short a day of Hearing to hear from the RCM Tree witness and our proposal to the Board and it will be subject to the Board's availability would be on Monday the 20th of June to have Mr. Stephen Weiss, the witness at RCM and TREE want to put forward, come to Winnipeg.

There is also the possibility that there will be two (2) witnesses from the Pembina Institute, Amy Taylor and Matt McCullan (phonetic), but, the decision on whether they will testify is still being finalized.

But, in any event, if they did come to Winnipeg, those witnesses together with Mr. Weiss would all be heard on the 20th, that's Monday the 20th of June.

That would complete the evidentiary portion of the Hearing and the parties are requesting approximately one (1) week to prepare and get their oral arguments ready. Some parties are interested in perhaps having the option of submitting a written argument rather than oral argument and some are still wondering whether or not, they could provide their oral argument from -- by teleconference.

And those issues we'll still work on. But the oral argument was proposed and comes before you as a proposal for Monday, the 27th, that would be a week following the evidence of RCM and TREE.

I appreciate that that comes at you fast this morning. I will try to sketch it out on a calendar, but, essentially we need to see if the Board is available to add one (1) Hearing day on the 20th of June and an extra Hearing day on the 27th of June. The 20th of June would be for the TREE RCM witness or witnesses and the 27th of June would be the oral submissions.

So that's where the timetable sits from yesterday -- from yesterday's discussion and I'll wait to hear back from the Board in terms of availability and whether that would be workable.

THE CHAIRPERSON: Mr. Peters, can we understand that the other parties present are -- are in agreement with this proposed schedule?

MR. BOB PETERS: That is -- you can have that understanding and if I have overstepped my bounds I'm sure they're going to grab the microphone and pull me up short.

But that is what we talked about yesterday. I did send an e-mail out last evening and I did hear from Peter Miller this last evening as well. He's not present in the hearing room today. He indicated that Mr. Weiss is, in fact, available on the 20th of June, on the Monday and would be available to testify if that date suits the Board.

THE CHAIRPERSON: I've consulted with my Panel colleagues and we're all right with this with one

(1) possible exception being the 20th and the possible exception may be that we'd have to conclude that day no later than two o'clock so we may propose starting a little early that day but that's conditional on a few things developing yet, so, other than that, we're fine.

MR. BOB PETERS: All right. Well, thank you for that then and the parties will -- will have this now as notice that the timetable that we had talked about yesterday is the one that we will work towards.

Should there be any changes or alterations I'll certainly bring it back to the Board's attention. But we plan to complete the hearing on, as we've discussed, on the timetable this morning.

THE CHAIRPERSON: We could always start on the 20th a bit earlier and shorten the lunch?

MR. BOB PETERS: Agreed.

Vincent Arthur Warden, Resumed
Howard Paul Stephens, Resumed
Lori Stewart, Resumed
Brent Sanderson, Resumed
Darren Rainkie, Resumed

THE CHAIRPERSON: Okay, Mr. Peters, we're all set for you again.

MR. BOB PETERS: All right. I will pass the microphone to my colleague, Ms. Murphy. There were a couple of matters that I believe the Utility wanted to address this morning before we started.

MS. MARLA MURPHY: Thank you.

Good morning, Mr. Chairman, members of the Board.

There's a couple of matters left from yesterday that we wanted just a moment to clarify. Mr. Warden and Mr. Stephens have issues to address. So I'll perhaps let Mr. Warden address his issue first.

MR. VINCE WARDEN: Thank you. Good morning and, yes, my issue was with respect to a response I provided to Mr. Saxberg in response to a question he had as to the -- whether there was any difference between retained earnings and reserves.

I think I indicated something to the effect that the term "reserves" was an outdated term and that is correct as far as Manitoba Hydro was concerned. We dispensed with the -- the terminology "reserves" back in 1992.

However, it's still -- still, and it was pointed out to me, my answer wasn't technically correct because it's still a very legitimate term and is referenced in the CICA handbook as being an appropriation of retained earnings.

So a company could very well have retained earnings appropriated for different purposes and that's where the -- the term "reserves" would be -- would be useful. For example, Manitoba Hydro could have an appropriation for drought, for example.

We could have retained earnings of -- of a billion dollars and -- and determine that we required a reserve for -- for drought of 2 billion and, therefore, the reader of the financial statements would know to the -- the extent to which retained earnings were deficient for that particular risk.

So that was my point of clarification. Thank you.

THE CHAIRPERSON: Thank you, Mr. Warden.

Mr. Stephens...?

MR. HOWARD STEPHENS: Good morning, sir, members of the Board.

Yesterday in my discourse with Mr. -- what's your name again? -- Mr. Peters, we had some discussion with respect to the provision of alternate supply for interruptible customers and it appears that I misspoke.

When we provide alternate supply to interruptible customers, we do it on a customer-by-customer basis. They have to make a positive election unless the delivered service, which comprises the alternate service, is a lower price than their sales rate.

Then we sell the gas to them without contacting them and they only pay what it costs us. As opposed to what I indicated yesterday where we would charge the sales rate and there would then necessarily be a premium.

So in this circumstance they -- to the extent that we can obtain the gas, we pass that through to them at whatever our cost is.

And in terms of allocating the costs as opposed to class versus customer, it's done on a customer by customer basis, because some of the customers choose not to take it.

MR. BOB PETERS: Right.

MR. HOWARD STEPHENS: I hope that clarifies matters.

CONTINUED RE-CROSS-EXAMINATION BY MR. BOB PETERS:

MR. BOB PETERS: And if I was listening carefully, I -- I'm just not sure I understood the one (1) aspect of it.

In the event that you have an interruptible customer that you would plan to interrupt because of constraints, but you can obtain delivered service to Winnipeg at a price lower than the sales rate that would ordinarily be charged to that customer, would you even notify the customer of it, or you'd just continue to provide gas to that customer?

MR. HOWARD STEPHENS: We would just continue to provide gas as if -- as if there were -- from his perspective there would be -- it would be absolutely transparent until he got his bill and he would realize that the cost that he's being charged on those days is actually lower than what the sales rate is.

MR. BOB PETERS: I'm just wondering if you can provide gas to an interruptible customer cheaper than what the regular sales rate would be; why would you provide the discount onto the interruptible customer?

MR. HOWARD STEPHENS: That's -- this is -- this is assuming that I've already provided or acquired sufficient delivered service to satisfy our firm requirements. So -- and this is just a way to maintain good customer service and be cognizant of the fact that the interruptible customers prefer not to be interrupted.

MR. BOB PETERS: All right, thank you. I understood from Mr. Warden's evidence yesterday, that the company was contemplating filing a report to the Board, dealing with fixed price offerings; did I have that right?

MR. HOWARD STEPHENS: Yes, that's correct.

MR. BOB PETERS: And that hasn't yet been filed has it?

MR. HOWARD STEPHENS: No, we plan on filing that this morning.

MR. BOB PETERS: All right. Well without having seen the report and while Ms. Stewart is still staffing the Panel, I wanted to ask a couple of questions of her and Mr. Stephens, relative to fixed price offerings by the utility.

Presently your supply contract with Nexen, Mr. Stephens, is one (1) that has the price fixed and set on a -- on a monthly basis; correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: Is it possible in the market for you to go out and get a fixed term contract for say a one (1) year period?

MR. HOWARD STEPHENS: Well, actually the existing Nexen contract has the provision that we can come to -- well, we can discuss and come to agreement as to how to manage a fixed price arrangement, should we desire to do so. It's something we contemplated when we negotiated the contract.

MR. BOB PETERS: Is that contemplation that you have in the contract for the entire supply or for only a portion of system supply?

MR. HOWARD STEPHENS: For only a portion.

MR. BOB PETERS: So under the existing contract, there would be an opportunity for you to discuss with the supplier, a fixed price arrangement for a certain portion of the volumes?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And in terms of the -- the duration of the term for the fixed price on a portion of the volumes, is it -- is it open ended for the duration of the contract with Nexen?

MR. HOWARD STEPHENS: It would be for no longer than the duration of the contract obviously, yeah.

MR. BOB PETERS: And that matter's a subject of negotiation?

MR. HOWARD STEPHENS: That's correct, we haven't hammered out the details in terms of the logistics -- I can't talk this morning, as to how it would work precisely. But I mean, there is a provision there.

MR. BOB PETERS: And presently in the

marketplace in Manitoba, there are five (5) year fixed price offerings being offered; is that correct?

MR. HOWARD STEPHENS: As I understand it, yes.

MR. BOB PETERS: And under your arrangement with Nexen, you would not have the ability to offer a five (5) year fixed price contract to your customers, would you?

MR. HOWARD STEPHENS: We wouldn't be able to provide a five (5) year fixed price contract that was underpinned by Nexen, but if there was a need for a five (5) year fixed price contract, I would think that we could likely make arrangements to underpin the remaining term with another supplier.

MR. BOB PETERS: Would that be in violation of your existing agreement with Nexen?

MR. HOWARD STEPHENS: No, that -- I mean, I'm -- I meant it in the context that to the extent it was a five (5) year term and we only had two (2) years left with the Nexen contract, for the remaining three (3) years when we were no longer bound by the Nexen contract, we would go to a separate supplier and underpin the arrangements that way.

MR. BOB PETERS: And this would be for the physical supply itself?

MR. HOWARD STEPHENS: Sorry, Mr. Peters?
MR. BOB PETERS: The fixing for up to a five (5) year arrangement then, would be on the physical supply itself, you'd have a fixed price arrangement?
MR. HOWARD STEPHENS: That's correct.
MR. BOB PETERS: And would -- would your existing contract allow you to adjust the volumes on a regular basis over the course of the year as customers migrated to and from any such fixed price offering?
MR. HOWARD STEPHENS: That is one (1) of the logistical issues that we have to address.
MR. BOB PETERS: Presently there's no provisions in place for how that would be handled?
MR. HOWARD STEPHENS: No.
MR. BOB PETERS: In general terms, if you were to try to fix a five (5) price offering would you expect it to be at a premium over and above existing primary gas rates?
MR. HOWARD STEPHENS: That's my general sense. I mean what you're essentially doing is having the supplier take on the risk associated with the pricing of the supply, so there is going to be some cost associated with that.
MR. BOB PETERS: I don't have the May 1st primary gas order handy, but, I thought it was

approximately twenty-nine cents (.29) a cubic metre?

MR. HOWARD STEPHENS: I'll take that as a reasonable number.

MR. BOB PETERS: Well let's round it off to thirty (30) because it's easier for me to remember.

If the current -- if the current price on your quarterly primary gas rates is set at say thirty cents (.30) a cubic metre, what type of premium would you be expecting as being reasonable for fixing it to a five (5) year term?

MR. HOWARD STEPHENS: Well, what would be reasonable I guess, is really in the eye of the beholder and that would be the customers that are seeking the fixed price. So I don't know that I want to characterize or -- I mean give an opinion as to what the appropriate premium should be.

It will be whatever the market will bear and the cost of the optionality. Now, whether or not, that's attractive to the consumer in the end is another matter.

MR. BOB PETERS: Well, is that a matter of negotiation or is that a matter of just taking what the market is offering?

MR. HOWARD STEPHENS: Well, when you go out to fix the price they will price out the optionality associated with it. So it will be a function of the marketplace.

MR. BOB PETERS: Ms. Stewart, if -- another way to provide a fixed price offering, would be through using derivative instruments; would you agree with that?

MS. LORI STEWART: Yes.

MR. BOB PETERS: Through derivative instruments can you hedge or price protect the cost of natural gas out, say five (5) years?

MS. LORI STEWART: Well, there's an issue with regards to the way our physical contract is currently structured because of course we have base-load volumes that are priced at a monthly index, however, our swing volumes are priced at a daily index.

And it would be challenging to hedge the daily -- those volumes that are pinned to the daily index. So -- and of course consumers in looking for a fixed price offering are not -- they're looking for all of their volumes to be hedged. At least that's how I envision an offering like that working. So we've got some constraints given our current physical contract, Mr. Peters.

MR. BOB PETERS: And I'm just trying to understand those constraints and I'm -- the base-load, can you use base-load for offering out a fixed price contract, a new price offering, or would you be restricted in using the base-load for that purpose?

MS. LORI STEWART: Well, we would then have an issue of cross subsidization between those customers who elected the default supply option and those customers -- utility customers who elected a utility fixed price offering because, of course, our base-load volumes are at index, while our swing volumes carry a premium.

MR. BOB PETERS: What you're saying then is that your -- if any customers on a fixed price you'd have to fix that under the base-load volumes which would then make it the responsibility of your system supply customers who want the floating price to carry the premium that's associated with the swing volumes that would now be assigned to them?

MS. LORI STEWART: I think before we go too much further down this path, what I'm suggesting is that we wouldn't be utilizing our current physical contract in order to create a fixed price offering in the Manitoba marketplace.

We would go about shopping around a fixed price offering in -- in a discreet way for the -- the number of customers that we expected could take a fixed price offering.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Stephens, did you tell the Board yesterday that the Nexen agreement expires October 31st of '07?

MR. HOWARD STEPHENS: That's correct unless we choose to renew it.

MR. BOB PETERS: And we talked about a number of steps that would happen in advance of any such renewal; correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: You said to me this morning that if you wanted to have a fixed price arrangement with Nexen you would only have it in place up until October 31st of '07 and after that you would be able to go out and source another supply from another supplier?

MR. HOWARD STEPHENS: Correct.

MR. BOB PETERS: Is there anything in the agreement that you have with Nexen that would preclude you from going to a five (5) year arrangement with Nexen, recognizing your existing arrangements expire October 31 of '07?

MR. HOWARD STEPHENS: Anything is
possible, sir. Certainly that would be a scenario that we would look at in terms of trying to accommodate the customers' requirements.

MR. BOB PETERS: All right. Ms. Stewart, you indicated that you would "shop for a new offering", those are my words, I'm not sure if they're exactly yours, rather than deal with your existing volumes under your existing contracts; do I have that correct?

MS. LORI STEWART: There would be -- there are a number of considerations in terms of how the utility would bring a fixed price offering to the marketplace, Mr. Peters.

And I'm attempting to describe that our current contract has some constraints associated with it and I don't want to leave the impression with the Board that Nexen would necessarily be the -- the provider of the utility's fixed price offerings.

However, Mr. Stephens, there are some contractual terms embedded in this contract at this point in time which provides Nexen with the right of first refusal. So there's a whole mix of things that are working here that really we -- we don't have a definitive answer for in terms of how would we come to market.

MR. HOWARD STEPHENS: Those were the

logistics that I was speaking of earlier that we haven't sorted out.

MR. BOB PETERS: All right. I didn't want to go too far down this road recognizing we haven't seen the report or the position of the company and I take it that's a matter that Panel 3 will be prepared to address as well?

MR. VINCE WARDEN: Yes, correct.

MR. BOB PETERS: Mr. Sanderson, when it comes time for you to procure the gas that you do for the Corporation, you turn to Mr. Stephens and basically say, this is how much we need on certain days, go get it?

MR. BRENT SANDERSON: Well, we look out and we -- we discuss what the forecast tells us we'll need but, at the end of the -- the day, Mr. Stephens and his group acquire whatever gas the market requires, whether that's what we had forecast or whether it isn't and as we all know that on a daily basis conditions are routinely other than what was forecast. So he acquires all the gas the market requires on a given day.

MR. HOWARD STEPHENS: I think there's a distinction that needs to be drawn there, Mr. Peters. I mean, Mr. Sanderson's working from a budget perspective and looking at normalized volumes.

When we're contracting for supply we're

looking at a max year scenario and the most cost effective way to satisfy that.

MR. BOB PETERS: I appreciate the distinction, Mr. Stephens, thank you.

Mr. Sanderson, when it comes time for preparing your budget, there are a number of inputs that you have to have in your budget, including such things as the number of customers and the volumes those customers are going to utilize in a normal year; correct?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: And who provides that information to you?

MR. BRENT SANDERSON: Manitoba Hydro's Market Forecast Department.

MR. BOB PETERS: And they'll be on the third Panel; is that correct?

MR. BRENT SANDERSON: Mr. Kuczk oversees that function and he'll be able to respond to any detailed questions regarding the load forecast, yes.

MR. BOB PETERS: All right. Do you handle how the annual fuel gas requirements are determined?

MR. BRENT SANDERSON: Yes, I do.

MR. BOB PETERS: Can you explain to the Board how you determine what your fuel gas requirements will be?

MR. BRENT SANDERSON: It would depend on whether we're talking about US pipeline systems such as Great Lakes or A&R, or the Trans Canada system. Certain pipelines in the US have federally mandated compressor fuel assessment parameters, where the regulator determines in advance the assessment levels as a percentage of the volumes transported down those lines, that they are allowed to -- to remove from the gas stream as pipeline fuel.

On the TCPL system, it's -- it's more of an operational issue, and it's determined in each month, as the case may be. So in -- depending on the pipeline, I would look at the US systems and what the federally approved compressor fuel ratios are.

Canadian pipeline systems we would look at the most recent year of actual experience on a monthly basis, as to what the compressor fuel assessment ratios were, and then we look at our load and what absolute volumes of compressor fuel we expect to be required to supply in order to transport our volumes to the load.

And then we have our market price forecast for each month, derived from the futures markets, which we then apply to those volumes to determine the cost levels of our compressor fuel costs for the upcoming forecast period.

MR. BOB PETERS: And your fuel costs are based on the most recent price strip when you come to the Board for your regular pricing?

MR. BRENT SANDERSON: Yes, that's correct.

MR. BOB PETERS: And in the event that -- do pipelines that have fuel gas ratios and requirements from you, always use gas fired facilities to transport the gas?

MR. BRENT SANDERSON: Not always, no. Trans Canada has a combination on their system of gas fired compressors and electric compressors. For example, their compressor station at -- near Eldisheen (phonetic) exclusively uses electric fired compressors.

MR. BOB PETERS: Do you compensate Trans Canada Pipeline with fuel gas, or do you compensate them by increased tolls when they have electric compressor stations?

MR. BRENT SANDERSON: In the case where they would be using electrically powered pipeline compressors, the costs to run those facilities would be imbedded in the variable transportation toll that we pay to the -- to the pipeline system.

MR. BOB PETERS: Mr. Sanderson, does

Centra treat system supplied customers identical to WTS customers in respect of fuel gas?

MR. BRENT SANDERSON: Yes, we do.

MR. BOB PETERS: Mr. Sanderson, once you have your forecasts and you get those on a weather normalized basis and you add in your fuel gas, you also then have to add in unaccounted for gas in determining what you're going to need to bring to the Manitoba marketplace; is that correct?

MR. BRENT SANDERSON: Yes, that's correct.

MR. BOB PETERS: And last time we were before the Board on cost of gas matters, the unaccounted for gas was -- was reviewed by the Board; correct?

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: And you had done an internal analysis, and tried to attribute as best as possible, the source of unaccounted for gas to various causes; correct?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: And then those causes were looked at by -- on a class by class basis, to determine which customer class caused or likely caused the unaccounted for gas to occur?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: And that led to the Board decision, which changed the methodology in which Centra was allocating its UFG percentage amongst customer classes?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: And from the -- from the allocation that the Board approved in the last cost of gas hearing, has anything changed to the allocation of unaccounted for gas in this hearing?

MR. BRENT SANDERSON: No sir.

MR. BOB PETERS: Has the overall percentage of unaccounted for gas changed?

MR. BRENT SANDERSON: No, we are still using a UFG percentage of .9 percent.

MR. BOB PETERS: I noted in -- it was in PUB/Centra 32(a) there was a UFG percentage for the forecast year of 04/05 of 1 percent.

And I'm not sure if I'm splitting hairs here or not, but, a 1 percent UFG percentage was that determined on an actual basis or was that still forecast?

MR. BRENT SANDERSON: Can you give me that reference again, please sir?

MR. BOB PETERS: PUB/Centra 32(a).

(BRIEF PAUSE)

MR. BOB PETERS: I didn't put that in the Book of Documents, Mr. Sanderson, but I just wanted to find out if the UFG percentage has been increasing from what the Board was last advised?

MR. BRENT SANDERSON: What I can tell you without -- if you just give me one (1) moment, I'm just going to read that -- that IR.

(BRIEF PAUSE)

MR. BRENT SANDERSON: That 1 percent figure that is embedded in the '04/'05 forecast figures, that was the percentage -- the most recent calculation available at the time that the original 2004/2005 gas cost forecast was prepared. We provided subsequent updates to that forecast prior to the Hearing which occurred this past September of 2004.

And the UFG percentage that is embedded in our rates that are currently approved is an amount of .9 percent and that continues to be the amount that's embedded in our forecast for the 05/06 fiscal year.

MR. BOB PETERS: And how is the .9 percent figure arrived or derived?

MR. BRENT SANDERSON: This is a calculation that's performed by the market forecast department. But, to the best of my recollection it's the most recent five (5) year average of actual unaccounted for gas experienced rounded to the nearest 10th of 1 percent.

MR. BOB PETERS: Mr. Stephens, yesterday we briefly talked about UFG and providing it to Manitoba. When you -- if you need a hundred (100) units of natural gas to come to Manitoba and you know that there's going to be unaccounted for gas by the time it gets burned at the burner tips, do you buy additional gas in advance or do you wait and pick it up on a spot basis, depending on how short the system is to balance it?

MR. HOWARD STEPHENS: We don't take UFG into consideration when we nominate supplies from Alberta to the City gate. UFG occurs on our system, our distribution system on the other side of the City gate. And it's more an accounting issue as opposed to a physical gas loss issue.

So from that perspective to the extent that there is a physical component to it, it would impact our system line pack. And the other component of it, it's simply is the accounting treatment for it.

MR. BOB PETERS: Well, in light of that

answer, Mr. Stephens, would it be -- why wouldn't it be possible for a customer and let's just pick the special contract customer because the unaccounted for gas is forecast to cost them approximately $300,000 in the test years; correct?

MR. HOWARD STEPHENS: As I recall, yes.

MR. BOB PETERS: All right. And for $300,000 if that -- if the customers in the special contract class could arrange to deliver natural gas to City gate, would that not keep you whole and allow them to source gas at whatever cost they can, rather than take the financial consequences of it.

MR. HOWARD STEPHENS: It would immediately put the system out of balance. I guess that's the concern that I have, in terms of making the delivery of the physical gas because not all of that gas is going to be gas that's attributed to physical losses assets.

Some of it is just an accounting treatment and the fact that we bill on different cycles relative to the cycles that we are billed on. And so from that perspective I find that it would be an extremely complex process and subject to very much interpretation.

So, from that perspective, I don't think that the customer would necessarily benefit as much as --

as it would appear on the face of it.
MR. BOB PETERS: Let me just explore that further. If -- if special contract customer class members phoned you up and said, on -- on January the 5th we're going to ship you three hundred thousand dollars ($300,000) or so many gigajoules of natural gas, make sure you balance accordingly, wouldn't that resolve the problem from your perspective?
MR. HOWARD STEPHENS: It is theoretically possible, sir, but I would suggest that from an operational perspective it would complicate the operation of the system unnecessarily so.
And it would mean an extra level of balancing that we'd have to do with the customers which is already a challenge with respect to -- specifically with respect to the customers that we're discussing right now.
MR. BOB PETERS: Are you aware as to whether other utilities offer customers to deliver physical gas in lieu of paying unaccounted for gas?
MR. HOWARD STEPHENS: TransCanada Pipelines allows for -- and as part of the fuel requirement they incorporate their unaccounted for, right in the fuel requirement.
MR. BOB PETERS: Other than what may have

been discussed in the hearing room last year, Mr. Stephens, have you had any customers make that request of the -- of the utility?

MR. HOWARD STEPHENS: No, sir. I think they were satisfied with the end result of our -- the decision of the Board last year.

MR. BOB PETERS: Well, the end result of the decision of the Board was financially to their benefit; correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: Mr. Sanderson and Board Members, I now want to turn to the 2005/06 gas cost forecasts found at Document Number 9 or Tab 9 of the Book of Documents that I provided yesterday.

MR. BRENT SANDERSON: I think you may have your --

MR. BOB PETERS: Tab 8, sorry.

MR. BRENT SANDERSON: Tab 8, yes.

MR. BOB PETERS: It's Schedule 9.1.3(b), Mr. Sanderson?

MR. BRENT SANDERSON: I'm there, sir.

MR. BOB PETERS: You prepared that?

MR. BRENT SANDERSON: I did.

MR. BOB PETERS: And you prepared that based on a forward price strip as of March 15th, 2005?

MR. BRENT SANDERSON: That's correct.
MR. BOB PETERS: So what we do know is that if we ran a new forward price strip on June the 1st, it will be different than these numbers show there?
MR. BRENT SANDERSON: That's correct.
MR. BOB PETERS: And -- but overall, there is protection for the consumers and protection for the utility by way of the purchase gas variance accounts and deferral account balances -- or deferral accounts which will capture the swings in all of these costs?
MR. BRENT SANDERSON: That's correct.
MR. BOB PETERS: The primary gas and swing service are based on the Nexen contracts that Mr. Stephens told us are going to expire October 31, 2007?
MR. BRENT SANDERSON: Yes, with just the added clarification that base-load and swing gas both constitute portions of our primary gas supply. They both are primary gas even though there's two (2) different pricing mechanisms.
MR. BOB PETERS: Thank you. And there's no changes relative to the 2004/05 gas costs in terms of the contract pricing mechanism and other terms and conditions; is there?
MR. BRENT SANDERSON: No, there's not.
MR. BOB PETERS: So it's exactly the same

as the current year for which you're asking the Board to approve your actual results?

MR. BRENT SANDERSON: That is correct.

MR. BOB PETERS: And those actual results were in the two (2) exhibits that you provided yesterday and Centra Exhibit 7 which was an update of Tab 4 of the Book of Documents are the -- are the final figures that you have and nothing is left outstanding?

MR. BRENT SANDERSON: Yes, that's correct.

MR. BOB PETERS: In terms of the supplemental gas, that's based on the NYMEX strip for the US supply; is it?

MR. BRENT SANDERSON: Yes, the NYMEX strip with a basis differential adjustment between Henry Hub pricing in Louisiana on which the NYMEX pricing is based, and Oklahoma head station pricing, which is the point at which we would be pricing that -- those Oklahoma purchases.

MR. BOB PETERS: The storage gas is based on a projected balance as of March 31, '05, plus the fuel costs for the summer of 2005?

MR. BRENT SANDERSON: Yes, that's correct.

MR. BOB PETERS: Do you have an

opportunity, Mr. Sanderson or Mr. Stephens, to use the storage to try to mitigate gas volatility, the gas price volatility, or do you simply have to take what you can get and get into storage as quick as possible, when the summer months arrive?

MR. BRENT SANDERSON: The mechanism by which the storage gas reduces customer's volatility is a passive mechanism rather than a conscious active mechanism.

We fill -- the reason why we hold storage and fill it to capacity every summer, is to ensure that we can meet our winter load requirements. That's the fundamental purpose of storage and to reduce our overall transportation costs to move gas from the supply basins to the Manitoba market.

But the fact that we inject gas into storage over seven (7) summer months at seven (7) distinct market prices, and then withdraw it out at a single average inventory value over the winter months, is the way in which it provides additional stability to customer's rates.

And we update that average inventory value once a year at each November 1st quarterly primary gas rate setting, so that is the mechanism by which that storage provides an added element of rate stability for customers.

MR. BOB PETERS: And that storage gas, would it be more expensive or less expensive than what you're able to provide through the primary gas you purchase during the winter months?

MR. BRENT SANDERSON: It may be somewhat different, it could be more expensive, less expensive or it may -- it may very closely match what we're purchasing during the winter. The market will determine the relative prices one (1) to the other.

MR. BOB PETERS: Can you indicate to the Board, Mr. Sanderson, what US exchange rate was used to calculate Schedule 9.1.3(b) found at Tab 8 of the book of documents?

MR. BRENT SANDERSON: If you'll just give me one (1) moment please?

(BRIEF PAUSE)

MR. BRENT SANDERSON: We're using an exchange rate of one point two three (1.23) Canadian to the US Dollar.

MR. BOB PETERS: And for the Board's edification and -- and mine as well, the foreign exchange impacts your supplemental commodity, as well as other US tolls and tariffs?

MR. BRENT SANDERSON: Yes, that's correct.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Stewart, I think I covered this yesterday, but on line 48, the hedging impacts are shown, based on the market to market results as of March 15th, 2005?

MS. LORI STEWART: Yes, that's correct.

MR. BOB PETERS: And the capacity management revenues, Mr. Stephens, this is the $3.8 million that you promised to provide to -- to Manitoba consumers next year, through -- through your activities?

MR. HOWARD STEPHENS: I'm not that much asleep. There were no guarantees associated with -- with that number, and, but as it turned out we actually generated $3.9 million.

MR. BOB PETERS: That was last year and for next year --

MR. HOWARD STEPHENS: Oh, I'm sorry, I'm sorry.

MR. BOB PETERS: -- you're forecasting

three point eight (3.8).

MR. HOWARD STEPHENS: Yeah, three point nine (3.9) is for next year, this is three point eight (3.8) and that was the number that was the appropriate number.

MR. BOB PETERS: The forecast for next year of 3.8 million, Mr. Stephens, was that based on an -- on an average, is that the -- a three (3) year average or a five (5) year average?

MR. HOWARD STEPHENS: Five (5) year rolling average.

MR. BOB PETERS: And the -- leaving aside the primary gas costs shown on Schedule 9.1.3(b), the balance of the figures are the -- are the gas costs for which you're seeking approval in this Application and to embed into the -- the rates of consumers; is that correct?

MR. DARREN RAINKIE: That's correct, Mr. Peters. Schedule 9.1.4 is probably more instructive in that regard, because it splits it between primary and non-primary gas costs. I think that's at Tab 4 of your book of documents.

MR. BOB PETERS: It's actually at Tab 3, Mr. Rainkie, and that's exactly where we'll head with the Board and you. What you're telling the Board in schedule

9.1.4 found at tab 3 of the Book of Documents is that in this Hearing, don't get worked up about the primary gas numbers because that's not what you're applying for at this time?

MR. DARREN RAINKIE: That's correct. They're for illustrative purposes so that we have a total -- total budget. But, what's important is what's on line 8 in that schedule, the non-primary gas costs.

MR. BOB PETERS: Well, what's also important, Mr. Rainkie, I suggest is on the supplemental gas line, you're showing the Board that at existing rates, you're going to over recover approximately twenty nine thousand, three hundred and sixteen dollars ($29,316) on account of supplemental gas costs?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: And so you want supplemental gas rates from this Board to go down by approximately twenty nine thousand three hundred and sixteen dollars ($29,316)?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: And we can follow that through on the transportation line, the current rates are going to over recover your forecast transportation costs by $3.4 million and therefore transportation rates that the Board approves, you're asking that they go down by that $3.4 million?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: And unfortunately, the same can't be said for the distribution, but, that distribution relates only to the unaccounted for gas; correct?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: And the distribution on this page for unaccounted for gas looks like it's going up by eight hundred and twenty-eight thousand dollars ($828,000) and you want that amount reflected in increased rates through the distribution rate charged to consumers?

MR. DARREN RAINKIE: That's correct Mr. Peters.

MR. BOB PETERS: And Mr. Rainkie, the distribution rate here for gas costs which you've told the Board only includes the unaccounted for gas is going up because the commodity price of gas is going up?

MR. DARREN RAINKIE: That's correct, but, the distribution rate also includes the non gas costs, Mr. Peters, the UFG is the gas cost that are included in the distribution rate, just to be clear.

MR. BOB PETERS: Oh, and I think your Revenue Requirement Panel will -- of which I think you're on Mr. Rainkie, will have an opportunity to explain that to the Board.

But, what you want the Board to be aware of is the distribution rate is going up eight hundred and twenty eight thousand dollars ($828,000) on account of UFG. It's also going to go up approximately $12 million in the first test year, as a result of the rate increase the Board approved on an interim basis February 1st of '05?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: And Mr. Rainkie, you drew the Board's attention to line 8 on schedule 9.1.4, at tab 3 of the Book of Documents, that is the sum total of the rate reduction on account of gas costs that the Corporation has built into the rates that they've put before the Board in this case?

MR. DARREN RAINKIE: That's the reduction for base rates, Mr. Peters.

MR. BOB PETERS: And that clarification you've given us Mr. Rainkie, just reminds the Board and me that in addition to the base rates there will be rate riders that have to be addressed in respect of these gas costs?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: And there is a rate

rider coming off and there will be rate riders going on, as well?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: You've applied in this application, Mr. Rainkie, for a two (2) year GRA if I will, that is for a test year of 2006/2007 for gas costs, as well, correct?

MR. DARREN RAINKIE: No, Mr. Peters, I think we went over this or just touched on it briefly yesterday. Given that we believe we'll have a 2006/07 -- I'm getting my years mixed up -- I wish we could go back to calendar years, but, given that we'll probably have a 2006/07 annual cost of gas what we have embedded in our rates is just a 2005/06 cost of gas.

I think it's unreliable to be forecasting gas costs out that far right now.

MR. BOB PETERS: I mis-spoke and thank you for catching it Mr. Rainkie. But, the request you have for the '07 fiscal year relates only to non-gas costs?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: And that will be the subject matter to be addressed by the Revenue Requirement Panel, is that correct?

MR. DARREN RAINKIE: That's my

understanding, yes, that's correct.
MR. BOB PETERS: And since we talked yesterday, Mr. Rainkie, there was an understanding of this 2006/07 gas cost annual hearing occurring sometime early in the 2006 calendar year and that's still the plan?
MR. DARREN RAINKIE: I think -- yeah we would file the application, our normal filing is late January, early February and the Hearing might be sometime later in the year like right now in 2006.
I should mention subject to other -- other things on the regulatory agenda, possibly on the electric side.
MR. BOB PETERS: I don't think I'll go there, I'm not sure what you're ..
In this application Centra adjusted its customers numbers and volumes for '05 and '06; correct?
MR. DARREN RAINKIE: Yes, we updated our -- our estimates for that test year.
MR. BOB PETERS: And you used those same updated numbers and volumes for 05/06 and you simply carried them forward for 06/07 for the purposes of this -- of this information?
MR. DARREN RAINKIE: No, I -- in Tab 4 of the -- of the application we have full customer volume

forecasts for both 2005/06 and 2006/07. It's simply the cost of gas -- the same cost of gas number that we've used for both test years.

MR. BOB PETERS: But your methodology for adjusting customers numbers and volumes for 06/07 was the same as it was for the way that you updated 05/06 customer numbers and volumes?

MR. DARREN RAINKIE: That's my understanding. I don't think there's any -- subject to check on the Third Panel, I don't think there's any adjustments in the methodology between those two (2) test years.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Chairman, with that answer and those questions, I'd like to thank this Panel of Mr. Warden, Mr. Stephens, Ms. Stewart, Mr. Sanderson and Mr. Rainkie. Those complete my questions on the cost of gas issues.

THE CHAIRPERSON: Thank you, Mr. Peters.

Mr. Boyd, do you have any comments or questions of this Panel?

MR. SANDY BOYD: No, I do not.

THE CHAIRPERSON: Thank you.

Mr. Saxberg...?
MR. KRIS SAXBERG: Thank you, Mr. Chairman. With this early start I hope we will be able to finish by -- by lunch so everyone can enjoy the lovely weather today, they don't have to go back to the office.
THE CHAIRPERSON: Are you suggesting our break should be shorter?
MR. KRIS SAXBERG: Well, perhaps I'll examine until 10:30 then I'll take a break and then hopefully I'll finish up by lunch. The first order of business will be to pass out a book of selected documents that I have.

(BRIEF PAUSE)

MR. KRIS SAXBERG: I think this would be marked as Exhibit CAC/MSOS-3.
THE CHAIRPERSON: That's fine.

--- EXHIBIT NO. CAC/MSOS-A: Book of documents.

MR. KRIS SAXBERG: And as everyone's quickly leafing through it, you should find that there's nothing much in there other than a collection of documents that have been produced as part of the

Information Request process.

Except, and I apologize for this, for not having provided two (2) of the documents in advance, and that's just my disorganization.

But there are two (2) documents that the parties may not have seen, and they are at Tabs N and P. I don't think there's anything in there that's going to be of any controversy, they -- they're just with respect to the capacity on Trans Canada Pipelines.

MS. MARLA MURPHY: Mr. Chairman, I -- I find us in a difficult spot, it's -- it's hard to give to a Panel a booklet like this and ask them to accept that the information contained in here is complete, when they haven't been given an opportunity to look at it in advance.

I don't think it's appropriate that those items be marked as exhibits in this Hearing, there's no one here to speak to them. I don't know what they form part of, or what the surrounding information might have been.

If they want to be marked as identification, that's acceptable. But I -- I don't think they're appropriately exhibits in this type of Proceeding.

THE CHAIRPERSON: Mr. Saxberg, do you

have any thoughts, well, on this subject?

MR. KRIS SAXBERG: Since I've put them all together into one (1) document, perhaps we could -- we could call this Exhibit CAC-A for now, and then after I come to the point in my cross-examination where I'm dealing with those two (2) documents, if Mr. Stephens is able to comment on them, or identify them, then we'd be able to transform the whole exhibit from an A to a number.

THE CHAIRPERSON: Is that acceptable to you, Ms. Murphy?

MS. MARLA MURPHY: Certainly, I'd like the opportunity to address that when the time comes, but that's acceptable for now.

THE CHAIRPERSON: Very good then, please.

RE-CROSS-EXAMINATION BY MR. KRIS SAXBERG:

MR. KRIS SAXBERG: Good morning, Panel. I want to begin with the hedging program. This will be for you, Ms. Stewart.

Do you agree that this Board should evaluate the performance of the hedging program, in the context of giving its final approval to the results shown on Schedule 8.2 of the Application?

(BRIEF PAUSE)

MR. KRIS SAXBERG: That quick reference would be to Mr. Peters' documents at Tab 6?

MS. LORI STEWART: And your question once again was?

MR. KRIS SAXBERG: Do you agree that the Board should evaluate the performance of the hedging program, in terms of approving the results shown on Schedule 8.2?

MS. LORI STEWART: Not -- not entirely. The Board should also be evaluating whether or not the transactions cited on Schedule 8.2.0, whether or not they were conducted in accordance with the policy and the operating principles and procedures.

MR. KRIS SAXBERG: As an additional matter to -- to also reviewing the performance of the program in general, in terms of achieving its goals?

MS. LORI STEWART: I agree that the corporation is looking for the gas cost consequences of our hedged transactions should be approved by the regulator, and I'm suggesting that the basis of that approval would be whether or not the transactions were entered into, in accordance with our policy and operating principles and procedures.

MR. KRIS SAXBERG: But you -- you agree that the Board should also look at whether or not the program itself is accomplishing what it's intended to accomplish?

MS. LORI STEWART: Yes, I do. However, Schedule 8.2.0 is not related to the objective of our program.

MR. KRIS SAXBERG: Okay. And in terms of evaluating the performance of the program, is it fair to look at the costs of the program, and to look at the benefits of the program?

MS. LORI STEWART: That sounds reasonable.

MR. KRIS SAXBERG: At Tab 1 of CAC Exhibit A -- sorry, Tab A, I've attached the new derivative hedging program policy.

And can you confirm that the object of the program, the exclusive object of the program is to mitigate natural gas price volatility?

MS. LORI STEWART: Yes the objective of the program has been cited quite clearly in the policy.

MR. KRIS SAXBERG: And that is the sole objective of the program, there's nothing more to it?

MS. LORI STEWART: Yes that's correct.

MR. KRIS SAXBERG: And most definitely

the goal of the program is not to achieve lowest cost gas?

MS. LORI STEWART: That's correct. Having said that, of course, this -- the work of the gas supply division is to always be mindful of the cost of gas that we're procuring on behalf of customers.

MR. KRIS SAXBERG: The larger department within which this program runs?

MS. LORI STEWART: That's correct.

MR. KRIS SAXBERG: Whenever you hedge to reduce volatility, that's going to affect the price that you pay for gas in any particular year, correct?

MS. LORI STEWART: Yes, that's correct.

MR. KRIS SAXBERG: And it's as simple as saying because you've hedged, you're not going to pay market price?

MS. LORI STEWART: That's correct.

MR. KRIS SAXBERG: And in the last three (3) years because of the hedging program Centra has beat the market, paid less than the market price?

MS. LORI STEWART: Gas costs have been lower than what they would have been otherwise in the absence of our hedging program over the last three (3) years, yes.

MR. KRIS SAXBERG: You don't want to

agree to the term, beat the market?

MS. LORI STEWART: No I don't.

MR. KRIS SAXBERG: Out performed the market?

MS. LORI STEWART: For the purpose of moving things along, sure.

MR. KRIS SAXBERG: And just to get the numbers on the record, it's approximately $10 million in lower gas costs for 2004/05, correct?

MS. LORI STEWART: That's correct.

MR. KRIS SAXBERG: Last year, 2003/2004 it was $4.6 million lower gas costs?

MS. LORI STEWART: Subject to check, yes.

MR. KRIS SAXBERG: And for 2002/2003 it was $15 million lower gas costs?

MS. LORI STEWART: That sounds correct.

MR. KRIS SAXBERG: And I want to turn to the way that Centra measures the performance of the program and that's by quantifying the percentage reduction in volatility, is that correct?

MS. LORI STEWART: Yes that's correct.

MR. KRIS SAXBERG: And for 2004/05, the company's position is that volatility has been reduced by 53 percent as a result of the program?

MS. LORI STEWART: That's correct.

MR. KRIS SAXBERG: And you indicated to Mr. Peters that that percentage is primarily just a function of what's happening in the market, in that if prices -- settlement prices were in between the cashless collar, then the percentage of reduction in volatility would have been zero?

MS. LORI STEWART: Yes, that's correct, if settled prices for all twelve (12) months had landed between the floor and the ceiling, then the percentage reduction in volatility would have been zero.

MR. BRENT SANDERSON: I'd just like to that this opportunity to add something in that respect, there's two (2) mechanisms by which our hedges reduce rate volatility, both on an actual settled basis and where those positions are at the time we go to set rates.

So there is the possibility and the likelihood that in a year where all of the instruments would settled within the bounds of all of the collars we had placed for that year, those hedge instruments could still provide a not insignificant amount of rate volatility reduction due to the fact, where they may sit on a forward-looking mark-to-market basis, at the time that we go to set rates.

So they may settle with a zero realized value, but still may provide a -- an element of volatility reduction throughout the year when we go to set rates.

MR. KRIS SAXBERG: Thank you for that, it's a good qualification.

The sixty dollar ($60) tolerance measure that was used previously isn't something that -- that you're endorsing any longer?

MS. LORI STEWART: The company has moved away from -- from that measure, yes.

MR. KRIS SAXBERG: Now, I want to turn to Tab C in my Book of Documents. It's CAC/MSOS/Centra/90. And on the second page, at Item C, the question was posed:

"What would the volatility be, in dollar terms, to the average residential customer had the derivatives not been placed for the 2004/05 fiscal year?"

And the answer is:

"The volatility of customers' primary gas rates for the '04/'05 fiscal period, had derivatives not been placed, would have been twenty dollars ($20) per thousand cubic metre."

This compares to an actual primary gas

rate volatility during the same period of nine dollars ($9) per thousand cubic metres, which then derives this calculation of 53 percent; do you see that?

MS. LORI STEWART: Yes, I do.

MR. KRIS SAXBERG: And Mr. Sanderson, these are your calculations?

MR. BRENT SANDERSON: Yes, they are, sir.

MR. KRIS SAXBERG: And this is your methodology in order to determine percentage reduction in volatility?

MR. BRENT SANDERSON: Yes, it is.

MR. KRIS SAXBERG: Can you explain to me how the twenty dollar ($20), and the nine dollar, sixty cents ($9.60) figures were derived?

MR. BRENT SANDERSON: Wanting to be careful not to lose my audience here, we measure that in terms of the standard deviation of the rate itself over the period under examination, and without going into a complex mathematical exercise to describe in depth how a standard deviation is calculated, just suffice it to say that the standard deviation is a widely accepted standardized measure of variability around an average.

And so essentially what that standard deviation represents is the average of how the rate, the primary gas billed rate, varied around the average rate over that period.

So in the case of where we're looking at the twenty dollar and sixty-two cent ($20.62) per 10-3 m3 figure, we calculate what our rates would have -- our primary gas billed rates would have been, during the period in question, in the absence of hedging, and we look at the average of the variation of that rate, around the average of the rate over -- at that period, and that yields the standard deviation of twenty dollars and sixty-two cents ($20.62).

And then when we look at the actual variation it's the same mathematical exercise, only looking at the actual primary gas billed rates over that period.

I hope that's a satisfactory description.

MS. LORI STEWART: Typically, Mr. Saxberg, we wouldn't represent the volatility reduction in dollar terms, however, we were expressly asked that question, and thus provided the information in dollar terms.

MR. BRENT SANDERSON: I think in absolute dollar terms is not as meaningful a figure without having some idea of how that twenty dollar and sixty-two cent ($20.62) figure relates to the average rate over that period; that's why we express it in percentage terms.

MR. KRIS SAXBERG: Are we talking about a per month or per quarter?

MR. BRENT SANDERSON: It's just as we convey it, over an annual period. Looking at the -- that calculation has to be considered each rate during each month over that period.

MR. KRIS SAXBERG: So in terms of the primary gas line on a customer's bill, is this telling me that over the course of the year that that price, with hedges, was changing by one (1) cent a cubic metre and, or sorry, two (2) cents a cubic metre without hedging, one (1) cent with hedging. Am I --

MR. BRENT SANDERSON: No, I am afraid you're mixing up quantities. When you're talking about what the customer is paying in absolute dollar terms for the primary gas supply and we bill that something altogether different from the rate itself.

There's a number of other factors that affect the variability of the sum total of the line item that customers pay the utility for their primary gas supply.

This is more meaningful in that it isolates what's going on with their rate.

MR. KRIS SAXBERG: Unit -- this number isn't relating to the billed rate, then; it's -- it's relating to the unit?

MR. BRENT SANDERSON: It relates exactly to the billed rate, which is something altogether different, compared to what the customer's paying us in absolute dollar terms for the commodity.

MR. KRIS SAXBERG: If we can turn, then, to the last page in the same tab.

(BRIEF PAUSE)

MR. KRIS SAXBERG: This document, CAC/CENTRA-90(d) attachment is a depiction of the average customer's bill, month over month with the hedging program in place in one (1) instance and with the hedging program not in place in the other instance; is that fair?

MR. BRENT SANDERSON: Not having prepared it, and subject to check, I'll take you at your word.

MR. KRIS SAXBERG: The average customer, as represented by this document, would, in April, have received a bill of eighty three dollars and seventy-six cents ($83.76); correct?

MR. BRENT SANDERSON: I'll take that as given.

MR. KRIS SAXBERG: And then the bill changes dramatically in May and June as the summer arrives; it's all weather related?

MR. BRENT SANDERSON: I would say that the single biggest influence on the variability of the customer's bill is weather in Manitoba.

MR. KRIS SAXBERG: So in terms of the -- the -- from the customer's perspective, in appreciating what the hedging program is doing for him or her, they -- when they're considering volatility of their bill, the main factor is this weather implication?

MR. BRENT SANDERSON: When they're considering the variability of their bill, yes, I would agree.

MR. KRIS SAXBERG: And if they -- if they want to reduce volatility of their bill, there's an excellent way to do that, and that's with the equal payment plan; correct?

MR. BRENT SANDERSON: Absolutely, I would agree.

MR. KRIS SAXBERG: And if they -- if this average customer had an equal payment plan, then we'd see all of these numbers would be the same except for the true-up month?

MR. BRENT SANDERSON: And in certain cases where weather is extremely variable, other than normal. There may be some mid-year adjustment, but on the whole I would agree, yes.

MR. KRIS SAXBERG: And for whatever reason, if a -- a customer chooses not to be on the equal payment plan and is receiving their bill in the way that this document depicts, then in April they -- the only difference because of the hedging program is that there bill was -- was a dollar sixty-four ($1.64) less than it would have been otherwise?

MR. BRENT SANDERSON: Subject to verifying those figures, I would agree.

MR. KRIS SAXBERG: And if you were to do a percentage in the reduction of volatility for April based on that overall bill, I mean, it would be a small percentage wouldn't it?

MR. BRENT SANDERSON: I would disagree with you. It's impossible to measure volatility of a single quantity. You have to have a number of data points in a series to measure volatility.

The April bill is what it is with hedging and it is -- is -- and it would be what it would be without the effects of hedging, but there is no means of measuring volatility of the April bill, because the number is what it is.

MR. KRIS SAXBERG: Is there -- is there not some way to measure the percent reduction in volatility between the -- all of those months, the actual versus the -- without derivative hedging?

MR. BRENT SANDERSON: Oh, absolutely, the same mathematical methodology can be used to measure the volatility of the customer's monthly bill over the course of a year, just the same as we would do for the rate itself.

And I can say -- I can see where you're going with this and I can tell you that in terms of reducing the volatility of the customer's monthly bill, hedging will have probably what would appear to be an insignificant effect, because weather by far overshadows any of the effects of managing those monthly bills with derivative hedges.

So, weather is a far greater influence of how the customer's bill changes month over month, than the rate they pay to the utility.

MR. KRIS SAXBERG: When you did your customer research, did you specifically ask those surveyed or those in the focus -- the earlier focus group, whether or not they were interested in having their bills be smoothed, or just the one (1) component related to primary gas?

(BRIEF PAUSE)

MS. LORI STEWART: I would have to go back and review that research, Mr. Saxberg. Sorry, I haven't looked at it for some time.

MR. KRIS SAXBERG: And intuitively, one would think that the bottom line number for a customer is the -- the total bill that they pay.

Would you -- do you agree with that?

MR. BRENT SANDERSON: Not necessarily. In periods where our rates were extremely volatile and very changeable due to fundamental structural changes occurring in the natural gas wholesale markets, we were receiving the message loud and clear from our customers.

We feel that their changeability of their rate apart from their monthly bill was a concern to them, so I wouldn't say that that's their only concern, no.

(BRIEF PAUSE)

MR. KRIS SAXBERG: At the -- under the total column, on the document we're looking at, under the heading "Difference," it shows that the average customer paid twenty-five dollars ($25) less because of the hedging program; is that right?

MR. BRENT SANDERSON: I would agree that's what the numbers indicate.

MR. KRIS SAXBERG: And that's within that sixty dollar ($60) a year tolerance?

(BRIEF PAUSE)

MS. LORI STEWART: The -- the -- the technical definition of the sixty dollar ($60) tolerance is something different than what we're -- than what we're looking at right here.

MR. KRIS SAXBERG: My understanding was that the tolerance level of a average customer was that their -- their bill wouldn't increase by -- the primary gas component of the bill wouldn't increase by more than sixty dollars ($60) in a year, is that wrong?

MR. BRENT SANDERSON: The parameters of that indicator, which I would like to reiterate we -- we've set aside or we -- in terms of measuring the performance of our program, was that our original customer research in 1998 indicated that customers were willing to tolerate quarter over quarter increases or decreases in their annualized natural gas bill, plus or minus sixty dollars ($60), that's the accurate characterization of that -- those parameters.

These figures here are just summing up an annual period.

(BRIEF PAUSE)

MR. KRIS SAXBERG: But that twenty-five dollar ($25) figure is indicating that without the derivative hedging program, the only difference would be twenty-five dollars ($25) throughout the year in terms of the costs paid by the customer?

MR. BRENT SANDERSON: It's impossible to -- to make that determination, because these figures include the effects of actual weather variation and so forth and that sixty dollar ($60) measure that was previously referenced in years past was excluding the effects of weather on the customer's bill.

It was just due to primary gas commodity price changes only and this includes a whole host of other facts including billing percentage changes and so forth, so it does not isolate and parse out the bill volatility reduction due to the hedging program.

MS. LORI STEWART: To assist, Mr. Saxberg, we are already on the record as agreeing with you that weather plays a much more significant role in a customer's bill variability than does the derivatives hedging program.

MR. KRIS SAXBERG: If you turn to Tab I which is a document that the Panel's familiar with is from the Western Opinion Research Study that was presented at the last cost of gas hearing; correct?

MS. LORI STEWART: It's an excerpt from our study, yes.

MR. KRIS SAXBERG: And three (3) pages in -- actually it's the fourth page in and the heading is "Reasons for not joining EPP".

MS. LORI STEWART: I have the reference.

MR. KRIS SAXBERG: I'm looking at these reasons as to why customers would not want to smooth out or dramatically reduce the volatility of their -- their bills by joining EPP and to me they collectively state that that's because the customer is not interested in a reduction in volatility; is that fair?

MS. LORI STEWART: I'm not sure I can -- I can confirm that correlation, Mr. Saxberg.

MR. KRIS SAXBERG: Well, the third bullet down says that:

"Customers prefer having small summer bills."

That, to me, correlates to mean that they are not interested in having the same level of bill and a non -- a bill with reduced volatility; is that ...?

MR. BRENT SANDERSON: I think our interpretation of these results has more to do with customers wanting to know that they're paid up as they go, not necessarily that they're not concerned about bill volatility but they want to know that their bills are fully paid and they're square with the utility as they move through the year.

MR. KRIS SAXBERG: What effect does the hedging -- here's -- maybe I'll just cut right to the chase, what effect does the hedging program have on those customers that are enrolled in the equal payment plan?

(BRIEF PAUSE)

MR. BRENT SANDERSON: It has the -- it provides customers the benefit of giving them an added measure of certainty as to the variability in their rates that they may otherwise be exposed to during the coming year.

As I said, being on the equal payment plan is no guarantee that your equal payment amount will not vary throughout the year. If -- if we were to not hedge, for example, and we were to undergo a severe market price shock even customers enrolled in the equal payment plan would be exposed to what may amount to a significant adjustment in their equal monthly billing amount at some point mid-year.

So it does provide benefits to customers in terms of reducing their risk and uncertainty looking one (1) year out into the future.

MS. LORI STEWART: I guess we view those tools as working in concert, Mr. Saxberg. It isn't an either/ or. We would prefer that customers avail themselves of the equal payment plan and also enjoy the benefits that the derivatives hedging program is delivering by way of price volatility mitigation.

(BRIEF PAUSE)

MR. KRIS SAXBERG: I note that it's 10:30 and I'm going to switch to the cost side of the equation so perhaps it would be a good time to take a break.

THE CHAIRPERSON: Yes, that'll be fine, thank you. We'll come back and I think we're in good shape for time, we've a couple of things to talk about, we'll be back at a quarter to 11:00. Thank you.

--- Upon recessing at 10:30 a.m.

--- Upon resuming at 10:45 a.m.

THE CHAIRPERSON: Ms. Murphy, just to indicate, what we're going to do is we'll let Mr. Saxberg carry on with his questions. And then at the conclusion of it, and depending upon the responses from the Panel, we'll determine what we're going to do with this question on the two (2) items within his book of documents; what weight that we'll provide them.

Mr. Saxberg...?

MR. KRIS SAXBERG: Thank you, Mr. Chairman.

CONTINUED BY MR. KRIS SAXBERG:

MR. KRIS SAXBERG: I want to begin finishing up on that last area concerning the benefits of the program referencing Appendix D to my book of documents.

Mr. Sanderson, Appendix D is a calculation that you've performed?

MR. BRENT SANDERSON: Either myself or staff under my purview, yes.

MR. KRIS SAXBERG: And I just want to make sure that I'm clear about how the percentage reduction in volatility is determined. At the far right-hand column under "standard deviation" you have a figure of nineteen dollars and fifty-five cents ($19.55) and below that a figure of twenty-eight dollars ($28); you see that?

MR. BRENT SANDERSON: I do.
MR. KRIS SAXBERG: That's the standard deviation through the course of the entire year?
MR. BRENT SANDERSON: Standard deviation of the billed rate, yes.
MR. KRIS SAXBERG: And in order then to determine the percentage reduction in volatility what -- what you're simply doing is determining -- is correlating those two (2) numbers together and determining that the percentage increase for the number without hedging; is that fair?
MR. BRENT SANDERSON: I would turn it around and characterize it as the percentage decrease with hedging.
MR. KRIS SAXBERG: And really it's just a comparison of those two (2) standard deviation numbers; that's how the percentage reduction in volatility is derived?
MR. BRENT SANDERSON: Correct. The nineteen dollar and fifty-five cent ($19.55) figure is 30.2 percent less than the twenty-eight dollar ($28) figure.
MR. KRIS SAXBERG: And the reason for 2004/05 having a higher percentage reduction volatility is because there's a greater difference between the two

(2) standard deviation numbers; correct?

MR. BRENT SANDERSON: Sorry, I was just trying to digest some numbers in the schedule. Would you mind restating the question please?

MR. KRIS SAXBERG: The further apart numerically the two (2) standard deviation numbers are, the greater the percentage reduction in volatility; correct?

MR. BRENT SANDERSON: Depending on which direction you're looking they could be further apart but it can be a lesser reduction in volatility.

But, yes, if you're measuring -- if you're talking about the standard deviations calculated with and without hedging, the further they are apart, assuming that the number on an actual basis is less than the number without hedging, yes, that would be correct.

MR. KRIS SAXBERG: Is it more accurate to say, rather than a percentage reduction in volatility, we're looking at the percentage difference between the standard deviations with and without hedging?

MR. BRENT SANDERSON: Yes, but as I said earlier standard deviation is a standard measure of volatility or variability.

MR. KRIS SAXBERG: Perhaps for the last time, going back to Tab C on the very last page.

(BRIEF PAUSE)

MR. KRIS SAXBERG: I think, Mr. Sanderson, you gave me the answer that I was expecting to hear and that I wanted on the transcript, but, I want to say it one more time, just in case I didn't get it the way that I intended.

Did you agree that with the affect of weather, the impact of the hedging program does appear insignificant?

MR. BRENT SANDERSON: I may not be answering this in the way you would like, but, I would characterize it as weather is a far greater influence on the volatility of the monthly bill customers pay than the volatility of the rate they pay to the Utility.

MR. KRIS SAXBERG: And then to move it forward, you didn't disagree with what I just said, though?

MS. MARLA MURPHY: Mr. Chairman, My Friend, is putting words in the mouth of the witness. He's answered the question I think twice now at least in the way that he feels appropriate. And I'd ask for some direction in that regard.

THE CHAIRPERSON: I think we share Ms. Murphy's view Mr. Saxberg.

MR. KRIS SAXBERG: Okay.

CONTINUED BY MR. KRIS SAXBERG:

MR. KRIS SAXBERG: And with respect to the equal payment plan then is it also the case that it's difficult to see the affects of the hedging program, for the most part?

MR. BRENT SANDERSON: Could you rephrase the question? I'm not sure I understood it.

MR. KRIS SAXBERG: For a customer on the equal payment plan, in order to determine the benefits of the hedging program it's difficult for that person to determine the benefits of the hedging program to them?

MR. BRENT SANDERSON: To look at their monthly bill under the equal payment plan, I would agree. But, there is information that comes from the Utility that would allow them to make an assessment of the benefits of the hedging program. And that's why we calculate their percentage reduction in the primary gas billed rate for that purpose.

MR. KRIS SAXBERG: And would you agree with me that some customers may decide not to be on the equal payment plan because they don't have a concern about volatility?

MR. BRENT SANDERSON: I'm sure there's

some customers out there, I wouldn't venture a guess as to how many or what percentage of our customers those customers represent, but, I'm sure there's customers who don't care about volatility, in all likelihood because of the percentage of their household expenditures that natural gas costs represent.

MR. KRIS SAXBERG: If we could turn to Tab I in our Book of Documents, six (6) pages in, there is an excerpt from the focus group study which was presented at the last cost of gas hearing, do you agree?

MR. BRENT SANDERSON: It appears so, yes.

MR. KRIS SAXBERG: Sorry, you have to flip over one more page in that, to the heading, Key Findings and Implications.

And one of the key findings was that the actual price fluctuations that is the ups and downs did not appear to be at the top of mind concern among participants in that focus group; can you comment on that?

MS. MARLA MURPHY: Mr. Chairman, I'm sorry to keep interjecting, but, this Western Opinion Research has been filed and reviewed in two (2) hearings now and I'm not sure that it's appropriate to ask this Panel to comment on the report that was prepared sometime ago and without the benefit of having discussed it with the maker of the report.

THE CHAIRPERSON: I'm confident, Mr. Saxberg, we'll be brief on this line.

Mr. Saxberg...?

CONTINUED BY MR. KRIS SAXBERG:

MR. KRIS SAXBERG: Sure, I -- I just wanted your concurrence that there are those aren't as concerned with price volatility that a customer's --

MR. BRENT SANDERSON: I would agree that the key findings and implications of the focus group sessions on the part of the research organization are that the ups and downs or the actual price fluctuations did not appear to be a top-of-mind concern among participants, but I think if you read the study in its entirety, they -- the Western Opinion Research goes to special pains to -- to inform the reader that statistically valid conclusions can't be drawn from the focus group sessions, because of the size of the samples that were involved, the small number of customers.

So, I'll agree that's what it says, but I would be careful about drawing too refined a conclusion from that.

MR. KRIS SAXBERG: Okay, turning now to the cost of the program, would you agree that in a general sense, there are two (2) main types of costs to the program, those being the dealer margin cost, the execution costs, I'm counting that as one (1), and your administration costs, that is the cost to run the program at Centra?

MS. LORI STEWART: That sounds reasonable.

MR. KRIS SAXBERG: And the number that -- that's been put before the Board in the past with respect to the dealer costs, is between 1 and 2 percent of the customer's annual bill?

MR. BRENT SANDERSON: That's a number that's been used in the past as a very, very conservative illustration that was used at the time in the absence of any more definitive market research to put a finer point on the expected costs of hedging.

And at last September's costs, the gas proceeding, we pointed out that we had come into possession of some dedicated market research into dealer margin costs and what a hedger could expect in that respect.

And we put on the record at that time that that 1 to 2 percent, it now appears to be extremely conservative on the high side, and that's -- the research we are in possession of indicates that the expected dealer margin costs are significantly lower than that, or expected to be significantly lower. And we've actually looked into that in some depth as part of working on our retrospective hedging study. And that's at the much lower levels of expected costs were confirmed by a number of independent parties, both in risk management and derivatives dealers community.

MR. KRIS SAXBERG: Okay, and we'll wait to get that number when we receive your -- your study, but just so that I have a number for this hearing, the 1 to 2 percent, though, that does represent a range of between $4 million to $8 million dollars costs a year?

MR. BRENT SANDERSON: That was how we characterized it at the time, yes.

MR. KRIS SAXBERG: And now you're -- you're going to be presenting evidence to this Board after this proceeding that's -- that those costs are significantly less?

MR. BRENT SANDERSON: Absolutely.

MR. KRIS SAXBERG: Turning then to the program costs at Centra, do you have a figure that -- where you could tell us what the cost of the program is per year?

MS. LORI STEWART: An approximate figure would be a hundred thousand dollars ($100,000) per year.

MR. KRIS SAXBERG: Are there any employees that are dedicated to the program?

MS. LORI STEWART: Not exclusively.

MR. KRIS SAXBERG: And so if --it's just a hypothetical, I'm not trying to -- I'm not making any suggestions, but if the program was cancelled tomorrow, would the cost savings be a hundred thousand (100,000) or would it be something less than that because the nature that these employees are performing other functions?

MS. LORI STEWART: I would suggest it would be something less than that for the reason that you stated.

MR. KRIS SAXBERG: And did your hundred thousand dollar ($100,000) figure, does that include training costs or costs to consult with your risk advisory?

MS. LORI STEWART: Yes, it does.

(BRIEF PAUSE)

MR. KRIS SAXBERG: Do you have a position on -- on what is a reasonable amount to pay for this program in order to achieve the mitigation of volatility which has been achieved?

MS. LORI STEWART: No, I don't.

MR. KRIS SAXBERG: Now, there are also short-term other costs that are in the short-term that are connected with the hedging program; would you agree?

MS. LORI STEWART: To what are you referencing?

MR. KRIS SAXBERG: The impact of the program on the total cost of gas in any particular year? Sorry, costs or savings?

MR. BRENT SANDERSON: I wouldn't characterize those as costs of the program, Mr. Saxberg. The short run additions and or reductions to customers' gas cost that result from the hedging program are nothing more than the manifestation of the volatility mitigation delivered through the program.

If the program is to be effective in any way in reducing the volatility of customers' primary gas rates there has to be some amount, either in terms of an addition or reduction to customers' gas costs for there to be any material reduction in volatility.

And adhering to a systematic program -- a systematic rule-driven program over the long-term, those short run pluses and minuses will net out to zero (0) over the long run, notwithstanding the small levels of embedded dealer margin that the derivatives dealers charge to place those instruments for us.

MR. KRIS SAXBERG: In the long run it's going to net out to zero according to your economic theory, but that's only if you apply the same program without any modifications during that long run period; correct?

MR. BRENT SANDERSON: There is room to alter your program if you come into -- if the utility was to come into receipt of strong evidence with respect to customers changing attitudes towards primary gas rate volatility.

There is room to make changes but I -- I wouldn't say that those type of changes should be regular or -- or on a whim, if you will. The goal should be to adhere to a systematic program over the long term, notwithstanding the fact that you may need to change the parameters at some point due to the change in risk neutral position of the ratepayers on whose behalf you're hedging.

MR. KRIS SAXBERG: If the program hadn't been up and running in 2004/05, the gas costs would have been higher to the tune of about 10 million, right?

MS. LORI STEWART: Yes, that's correct.

MR. KRIS SAXBERG: And that's purely a function of the market. It could equally have been likely that because of the operation of the program in

2004/05 gas costs may have been increased by $10 million; correct?

MS. LORI STEWART: Yes, that's correct.

MR. KRIS SAXBERG: And you don't agree with my characterization of that as being a short-term cost associated with the hedging program?

MS. LORI STEWART: Well, certainly I can't agree with the characterization when it reduced customers' gas costs by 10 million.

MR. KRIS SAXBERG: Cost or savings; that in the short run there can either be a cost or savings associated with that hedging program?

MS. LORI STEWART: In the industry, Mr. Saxberg, the costs associated with the program are the administrative costs borne by the hedger as well as the dealer margin costs.

MR. KRIS SAXBERG: You're not relieved when, at the end of the year, the hedging program, because of the fortunate circumstances in the market, produces a reduction in gas costs?

MS. LORI STEWART: As a ratepayer, Mr. Saxberg, I'm as pleased as anyone else if gas costs are less than what they would have been.

However, I wouldn't characterize my emotion as relief.

MR. KRIS SAXBERG: If the company found itself in a circumstance where the next five (5) years gas costs were increased because of the same program; which is possible, correct?
MS. LORI STEWART: Yes, that's possible.
MR. KRIS SAXBERG: And it's possible that over those next five (5) years they could increase each year by $10 million a year; are you saying that your attitude with respect to -- to the program would remain absolutely unchanged?
MS. MARLA MURPHY: Perhaps the question could be clarified, I'm not sure if we're dealing with Mr. Stewart's mental wellbeing or emotional state or whether we're talking about the company position on derivative hedging here.

CONTINUED BY MR. KRIS SAXBERG:
MR. KRIS SAXBERG: I'm talking about the company's position on derivative hedging.
MS. LORI STEWART: I can't predict, Mr. Saxberg, at what point in time there could be triggers for re-evaluation of our program. Certainly, management is continuously monitoring the programs that it has in place for its effectiveness and I really can't respond to that question.

MR. KRIS SAXBERG: I want to talk about the new policy now briefly. Without putting you on the spot would you agree with me, Ms. Stewart, that the executive committee now holds all of the discretion with respect to the hedging policy?

MR. VINCE WARDEN: Yes, I think I would agree with that.

MR. KRIS SAXBERG: That the company could hedge zero amounts of volumes if approved by the executive, correct?

MR. VINCE WARDEN: Correct.

MR. KRIS SAXBERG: And the company could use a cap or a swap at any time, if approved by the executive?

MR. VINCE WARDEN: Correct.

MR. KRIS SAXBERG: And you could use any formula other than the fifty (50) cent out of the money formula if approved by the executive?

MR. VINCE WARDEN: Right.

MR. KRIS SAXBERG: And you could unwind any transaction if approved by the executive?

MR. VINCE WARDEN: Yes.

MR. KRIS SAXBERG: Can the executives make these decisions without input from the gas supply committee?

MR. VINCE WARDEN: They wouldn't do that, I can tell you. I am the liaison between the gas supply committee and the executive committee and they wouldn't take any action without a recommendation coming through myself which would be supported by a recommendation of the gas supply committee.

MR. KRIS SAXBERG: And I think I heard Ms. Stewart say that the only time a recommendation would come would be if there were extraordinary circumstances?

MR. VINCE WARDEN: Yes.

MR. KRIS SAXBERG: And to date, have there been any recommendations with respect to seeking approval to change instrument or change the bandwidth?

MS. LORI STEWART: No there have not.

MR. KRIS SAXBERG: But, there certainly have been discussions about those matters at the gas supply committee level, correct?

MS. LORI STEWART: Yes, that's correct.

MR. KRIS SAXBERG: And ultimately, no recommendation came forward as a result of those -- those discussions?

MS. LORI STEWART: Well, we're looking at a revised policy as a result of those types of discussions.

MR. KRIS SAXBERG: And I'm just going to

ask you some very general questions about the study that you've undertaken. Firstly, I understand that there have been some preliminary findings, but that those findings are not finalized yet?

MS. LORI STEWART: We have some raw data and we're sometime away from completely the analyses as well as the commentary around those analyses. However, I am on the record as noting that our report will be filed by August the 1st.

MR. KRIS SAXBERG: I just want to ask you a couple of -- and I do mean only a couple, quick questions about the raw data. Did -- when you were doing your analysis, Mr. Sanderson, and did you run different formulas to note the performance of different formula with respect to historic years.

MS. MARLA MURPHY: Mr. Chairman, I might suggest that this line of questioning would be more appropriate once the report is actually filed and all the parties have an opportunity to review it.

THE CHAIRPERSON: Are you all right with that Mr. Saxberg?

MR. KRIS SAXBERG: Yes.

(BRIEF PAUSE)

MR. KRIS SAXBERG: I'd like then to change topics and talk about Oklahoma.
THE CHAIRPERSON: Are you referring to the musical, Mr. Saxberg?
MR. KRIS SAXBERG: I probably know more about that.

CONTINUED BY MR. KRIS SAXBERG:
MR. KRIS SAXBERG: Centra Exhibit 7 is where I want to start.
MR. HOWARD STEPHENS: Is this in your Book of Documents, sir.
MR. KRIS SAXBERG: No. No, it isn't.

(BRIEF PAUSE)

MR. KRIS SAXBERG: Now, there are two (2) transportation arrangements that have been negotiated to get gas from Oklahoma and Louisiana to fill storage; is that right?
MR. HOWARD STEPHENS: That's correct.
MR. KRIS SAXBERG: And in past years, when I looked at Schedule 8.0, there used to be a line item under, "Supply costs," for Louisiana and there isn't this year, do you still purchase gas from Louisiana?

MR. HOWARD STEPHENS: I don't believe there ever was a line item with respect to Louisiana supply. So I guess I'm refuting your --
MR. KRIS SAXBERG: Okay.
MR. HOWARD STEPHENS: -- position.
MR. KRIS SAXBERG: Have you purchased gas from Louisiana?
MR. HOWARD STEPHENS: Yes, we have indeed.
MR. KRIS SAXBERG: And so when you present that supply figure, where do you present it then?
MR. BRENT SANDERSON: To the extent that we would purchase Louisiana supply to refill the supplemental portion of our storage inventory. Those costs would be embedded in what is characterized as storage gas supplemental supply on line 42. It would make up part of that -- of the costs shown on those -- in that line.
MR. HOWARD STEPHENS: Just to add to that, Mr. Saxberg, you have to recognize that these numbers are prepared on the basis of normalized years. In a normal year we don't require Louisiana gas.
I stand corrected. Disregard my comments.
THE CHAIRPERSON: Only that one, I hope, Mr. Stephens?

MR. HOWARD STEPHENS: Well, you can pick and choose, Mr. Chairman.

CONTINUED BY MR. KRIS SAXBERG:
MR. KRIS SAXBERG: It's not often that you have to buy gas in Louisiana?
MR. HOWARD STEPHENS: It is the supply of last resort.
MR. KRIS SAXBERG: Did you buy any gas for 2004/05 from Louisiana?
MR. HOWARD STEPHENS: I'm just going to go from memory, Mr. Sanderson's going to rustle numbers up, but it seems to me that we did buy a small amount.

(BRIEF PAUSE)

MR. HOWARD STEPHENS: I am advised that the last time we purchased Louisiana was December '04. Summer '04, sorry. I was gong top say December is strange month for it.
MR. KRIS SAXBERG: But suffice it to say it's -- it's usually small volumes and it's not that often that you need to purchase Louisiana gas?
MR. HOWARD STEPHENS: It could be considerable volumes. I mean, we would have twenty-two

thousand (22,000) some odd gigajoules of capacity on the ANR Southeast pipeline and if we were to run that continuously throughout the course of the year, I mean, it would amount to a significant amount of gas.

MR. KRIS SAXBERG: Do you pay a specific monthly demand charge so that you can get gas from Louisiana, specifically for that purpose?

MR. HOWARD STEPHENS: We pay demand charges associated with -- it's a part of the overall ANR storage and transportation arrangement that we have. And it is one (1) component. The demand charges associated with that capacity are one (1) component of that arrangement.

MR. KRIS SAXBERG: If, for whatever reason, you no longer needed to purchase gas from Louisiana, would there be a possibility of any reduction in costs because you wouldn't need transportation arrangements?

MR. HOWARD STEPHENS: Well, two (2) reasons come to mind immediately. Obviously, we wouldn't bear the commodity cost nor the variable portion of the rate associated with that.

And the second component is, to the extent that it's possible, we will select a past gap and whatever we can generate in terms of revenues to offset our fixed costs, we would certainly endeavour to use them.

MR. KRIS SAXBERG: Okay. And looking then at line 41 on Centra Exhibit 7. Oklahoma supply, that line indicates that there was zero (0) purchase of Oklahoma supply, but that's not the case; right?

MR. HOWARD STEPHENS: That's the area that we got into yesterday where we turn into an exchange arrangement as opposed to buying the Oklahoma supply.

MR. KRIS SAXBERG: So item 43, line item 43, which was forecasted to be zero and actually turned out to be $8.6 million, is that where we see the other side of the equation, the exchange?

(BRIEF PAUSE)

MR. HOWARD STEPHENS: That's correct.

MR. KRIS SAXBERG: I want to refer you to CAC Information Request Number 154, which is in my book at Tab L.

And on page 2, can you confirm that Centra is saying that there's a four (4) year advantage of $4.9 million if Oklahoma Gas had been replaced with western Canadian supplies?

(BRIEF PAUSE)

MR. HOWARD STEPHENS: If you look at the commodity costs only, yes. I go at great length to explain that the landed cost and storage is far higher than the relative cost for the western Canadian supply and that's detailed in the following pages.

MR. KRIS SAXBERG: Would you be able to re-do that table, then, with inclusion of the transportation cost, but also, in doing so, include the transportation cost associated with the Oklahoma supply?

MR. HOWARD STEPHENS: Can I do it or will I do it?

It's no small order, but certainly it's something that I could endeavour to do, sir.

MR. KRIS SAXBERG: Would that exercise not answer the question as to whether or not there's a cost savings to be achieved from using western Canadian supplies rather than Okalahoma?

MR. HOWARD STEPHENS: No, I really don't think it's relevant. We are -- we have a long term supply or a long term storage and transportation arrangement with ANR which we recognized at the time when we entered into it, that was not necessarily going to deliver the lowest cost commodity.

So, from that perspective, there is an element of, if you will, philosophy associated with having a more diversified supply as a part of the portfolio, notwithstanding the fact that you're going to experience potentially incremental costs associated with it.

So, from that perspective, I can give you the, but I mean, the hard and fast numbers, but that's not the whole story.

MR. KRIS SAXBERG: Yeah, and I -- so, if I could ask you to produce those hard and fast numbers, and -- and I note that what you're saying is that the company, from a philosophical policy perspective, is prepared to pay a little more in order to have a diversity of supply and there's a benefit to consumers for that?

MR. HOWARD STEPHENS: Yes. And I think as time passes we may see that that benefit is -- it grows, over time.

The projections with respect to LNG in the Gulf, et cetera, are -- come to pass. I mean, we'll be able to obtain gas from the Gulf at a potentially lower cost than Alberta supplies.

MR. KRIS SAXBERG: In your answer to IR-154, you indicate that there's some transportation constraints for firm service on TCPL at 10 percent on the Great Lakes system, correct?

MR. HOWARD STEPHENS: Say that again, sir.

MR. KRIS SAXBERG: Well, in your answer you're saying that there are some transportation constraints associated with getting western supplies to storage on TransCanada, 10 percent also on Great Lakes?

MR. HOWARD STEPHENS: No, not onto TransCanada. TransCanada for the pre-fill period we have more than enough capacity.

The restriction or the limiting factor in terms of the refill is our summer capacity in Great Lakes.

MR. KRIS SAXBERG: Okay.

MR. HOWARD STEPHENS: And that was really designed to accommodate a refill after what was originally deemed to be a normal winter which would provide for about 10 million gigajoules of inventory being injected into storage from western Canada.

MR. KRIS SAXBERG: Okay. And I just want to talk about capacity on TransCanada pipelines for a moment, and this is the point where we're going to take a look at the document that Ms. Murphy has a concern over and that's at Tab N.

MR. HOWARD STEPHENS: I might add I have some concerns over this document as well.

MR. KRIS SAXBERG: Okay. Were you part of the Hearing that led to this information request being asked?

MR. HOWARD STEPHENS: We monitored it.

MR. KRIS SAXBERG: So, on the second page, there's simply an indication of the BCF available on TCPL and I -- is it something that you disagree with the accuracy of this document?

MR. HOWARD STEPHENS: Well, only to the extent that it's -- I mean, the document is provided out of context. I don't know the context that it's necessarily being provided in.

TransCanada can't confirm the numbers. TransCanada is -- has a -- an objective in mind with respect to providing these numbers and so those numbers will, presumably, suit that objective. And I mean, I don't want to cast aspersions upon TransCanada.

And I think that the last comment I want -- would like to make is that, I mean, these projections, especially when you're talking about something that's going out twenty (20) years, you have to take some of it with a grain of salt.

TransCanada, from my perspective, is

positioning themselves very well to be the transporter of any new supplies coming out of Alberta. And the fact that they're asking their shareholders to invest more money in the company indicates a high degree of confidence on the part of the company -- of the pipeline that they're going to be successful in doing so.

MR. KRIS SAXBERG: So, your view is you don't agree that extra capacity on TransCanada pipelines is going to continue to grow?

MR. HOWARD STEPHENS: No, all I'm saying, Mr. Saxberg, is that it's very difficult to predict this. The environment that we're working -- we're working within right now, and I alluded to this yesterday, is very much in a state of flux.

And where new suppliers come -- come from, whether it be LNG, Alaskan Gas, methane hydrates, what have you, the jury's still out and that will dictate which pipelines will be full and which ones will not.

MR. KRIS SAXBERG: Can you confirm from your monitoring of the Hearing that the table that we're looking at is TransCanada pipelines evidence?

MR. HOWARD STEPHENS: Correct.

MR. KRIS SAXBERG: And that it shows that for 2000/2001 there was 6.1 BCF and whereas in 2004/05 there's 5.2 BCF?

MS. MARLA MURPHY: Mr. Chairman, this document will have to speak for itself as we've put our concerns on the record. It is two (2) of a ten (10) page excerpt that's part of a piece of written evidence that was filed in a hearing, presumably was cross-examined upon, may have been updated or otherwise amended.

So, we have some difficulties with that. The document can speak for itself, but we can't ask Mr. Stephens to confirm the voracity of those numbers.

MR. KRIS SAXBERG: No, and I -- just for the record, I'm not asking him to confirm and I understand his qualification that he's made that he can't confirm that the numbers are accurate and they may be self-serving numbers.

However, there's been a lot of discussion at this Hearing about whether or not there's excess capacity in TransCanada pipelines.

This is the only evidence so far that the Board has with respect to whether there is or isn't any and the Board can measure its weight in its final determinations.

But we've identified the document as evidence from TransCanada Pipelines.

THE CHAIRPERSON: I think we have to conclude that without having the entire document here and without the ability to cross-examine the authors or those who participated in it, we can only provide it the weight that it is due.

But we understand you're developing a particular perspective and we understand, at the same time, Ms. Murphy's concerns and Mr. Stephens' reluctance in providing it any particular weight.

MR. KRIS SAXBERG: Thank you, Mr. Chairman. The other document which Ms. Murphy will object to is at Tab P and it's the -- an excerpt of evidence provided by an expert hired by TransCanada Pipelines. Is that a fair characterization of the document, Mr. Stephens?

MS. MARLA MURPHY: Again, I don't know that we can actually be commenting on that and my same concerns remain with this. Mr. Murphy is not a relative of mine but this is only a part of his evidence.

THE CHAIRPERSON: I didn't even notice that.

MS. MARLA MURPHY: Again, subject to cross-examination. It's a good name.

CONTINUED BY MR. KRIS SAXBERG:

MR. KRIS SAXBERG: Well, the only reason I'm -- I'm putting these forward is because I understood that Centra was participating in this hearing and so, therefore, would be able to know whether this evidence was presented and how it was treated and whether it was amended; isn't that fair?

MR. HOWARD STEPHENS: Well, you were misinformed in terms of participation. It would depend upon your definition of participation. We were playing a monitoring role with respect to the proceeding.

MR. KRIS SAXBERG: Let me try to get to it this way, do you agree that as a result of competition from other pipelines that the TransCanada Pipelines main line has seen a reduction in volumes?

MR. HOWARD STEPHENS: Well, there's no question that the -- I mean, the development and the introduction of the Alliance Pipeline, from the Western Canadian Sedimentary Basin, had a significant impact on TransCanada's throughput.

MR. KRIS SAXBERG: And that the TransCanada pipeline, as it stands now, is only one (1) of the pipelines that's in receipt of Western Canadian supply basin gas that's moving -- that's moving it out of Alberta; is that right?

MR. HOWARD STEPHENS: Yeah, they are one (1) of many. They are the most significant at last check -- the last time I checked.

MR. KRIS SAXBERG: And part of the reason why there's excess capacity is because of Alliance's success in signing long-term contracts?

MR. HOWARD STEPHENS: Yes. They did sign long-term contracts at essentially fixed tolls so there were -- they were a very attractive option.

MR. KRIS SAXBERG: And that -- that TransCanada Pipelines may also face loss of downstream market share as a result of competition from other pipelines elsewhere?

MR. HOWARD STEPHENS: That's -- there is a fair amount of speculation with respect to that comment. I mean, and I would not propose to predict what's going to happen to TransCanada in the long-term in terms of the eastern markets.

They've been facing that very issue since 2000 when we did intervene with respect to the issue of the Alliance pipeline coming on stream and the impact on TransCanada.

And our perspective at that time, that it wasn't in the public interest, the NEB found it -- found a different solution. So from that perspective, I guess, anything goes, Mr. Saxberg.

I guess the one (1) comment that I would like to make though is, it was -- we talk about the fact that they're becoming decontracted and that at the bottom on -- there is no pages number on it, question 15, they refer to the peak throughput on TransCanadaÆs system at just over 7 million gigajoules a day.

And that they're now only shipping 6 million gigajoules per day. That is the amount of firm capacity that they have contracted. That's not necessarily the amount of capacity that they're actually moving because they move a significant amount of volume under discretionary services.

MR. KRIS SAXBERG: Yesterday, there was some discussion about steps being taken by TransCanada Pipeline to reduce excess capacity.

Do you recall that?

MR. HOWARD STEPHENS: Yes, sir.

MR. KRIS SAXBERG: One of the items mentioned flows from PUB/CENTRA-73 and that is this intention by TCPL to convert one of its natural gas transmission lines to a liquid petroleum line; is that right?

MR. HOWARD STEPHENS: An oil pipeline, yes.

MR. KRIS SAXBERG: That's not something that is a given, it's not a firm plan, it's -- it's a proposal; correct?

MR. HOWARD STEPHENS: That's -- I mean it has a number of approvals that have to be gained and I think I went through the lit -- litany in terms of approvals that they have to go through in terms of having that approved.

MR. KRIS SAXBERG: And it also would come at a fairly considerable capital expense in order to convert the use of the pipe to oil transmission?

MR. HOWARD STEPHENS: I think that remains to be seen. I guess the most significant component of the capital expenditure will be the cost that the oil pipeline pays to the main line for the existing facilities.

MR. KRIS SAXBERG: So anyway, it's -- the upshot is, stayed tuned to find out whether or not TCPL really is going to take a step forward in reducing its excess capacity, it's not -- it's not a given today?

MR. HOWARD STEPHENS: That's correct. And I guess the other point that I would like to make and it is notably absent in this evidence, is that in -- in 2000 in TransCanada's application, they did apply for and received approval to accelerate the depreciation on the pipeline.

I mean, they make reference to the fact that the pipeline is only sixty-seven (67) as -- has only been depreciated to approximately sixty-seven (67) percent of its original cost.

That depreciation rate was accelerated in recognition of the fact that there was a competitive environment.

So, at this -- I'm try -- I make the point because it just illustrates the fact that we don't have everything in front of us here.

MR. KRIS SAXBERG: Okay. Thank you for that.

Are you aware of recent announcements in Ontario that there are going to be an additional, at least two (2), gas fired electric generation statements -- stations, coming on line?

MR. HOWARD STEPHENS: I'm aware that there are proposals. Whether or not they go ahead definitely or not is another matter?

MR. KRIS SAXBERG: How's that going to affect TransCanada Pipelines in excess capacity?

MR. HOWARD STEPHENS: It depends upon which segment of the main line you're talking about.

I mean, certainly down east they're talking about having to expand the pipeline in certain circumstances which, I mean, when you're talking about TransCanada's main line is contrary to logic, given the surplus that they have. But it is -- you're going to see, I think, from -- if TransCanada's forecast comes to pass, you're going to see a division in terms of where the capacity is required, and certainly down East, there is requirement for additional capacity to deal with things like power -- power plants, et cetera.

But there may be less requirement for capacity on the western leg of the system and certainly in the central leg of the system.

MR. KRIS SAXBERG: And just turning back to the Oklahoma situation for a moment. If -- if you were able to -- to make transportation arrangements to get additional western Canadian supplies into storage at the cheaper price, you -- you would be able to sell your excess capacity on ANR that you would have used otherwise; is that correct?

MR. HOWARD STEPHENS: Well, I hate to qualify these answers all the time, sir, but theoretically, yes.

MR. KRIS SAXBERG: And --

MR. HOWARD STEPHENS: But practically, because of the nature of the contractual arrangement that we have, we have discounted tolls associated with those contracts, with those transportation contracts.

We have fixed delivery points associated with them and if we go to secondary points, we go to full tolls, which very often takes the pipeline capacity out of the money.

MR. KRIS SAXBERG: But those types of capacity management sales have been done though; right?

MR. HOWARD STEPHENS: We're doing some right now. They don't generate a lot of revenue is what I'm telling you, because we do go to the max toll and, I mean, it's a function of the basis differential versus the max toll.

MR. KRIS SAXBERG: But at least that would offset some of the additional costs of transporting the western supplies into storage?

MR. HOWARD STEPHENS: Yeah, I guess. I mean, in the long run, yes, that certainly would be -- I mean you could take that of course and then say, yes, I've reduced my Western Canadian supply costs by the amount that I've attracted with respect to the sale of my capacity. It's not a significant amount though, I would suggest.

MR. KRIS SAXBERG: My consultant tells me that he's had a thing for Oklahoma for some time and in view --

MR. HOWARD STEPHENS: More power to him.

MR. KRIS SAXBERG: Or I should say a

thing against Oklahoma gas and he -- he was excited by the response to IR-154 that we're looking at and wanted to know whether it would be reasonable for the Utility to seek expert advice from someone, perhaps IGC, about the feasability of displacing Oklahoma gas injections with additional purchases of Western Canadian gas?

MR. HOWARD STEPHENS: Well, IGC did address this issue in their -- in their report and, indeed, they recommended that we increase the amount of Oklahoma capacity that we hold and that we reduce the amount of TransCanada capacity; that we increase the amount of storage that we hold, reduce the withdrawal capability of the ANR storage to make it a more seasonable type of service and then, finally, the TransGas alternative.

MR. KRIS SAXBERG: But that's in the context of accepting the entire optimized portfolio?

It's part and parcel of a series of recommendations in the optimized portfolio, correct?

MR. HOWARD STEPHENS: That's correct. But there again, it is -- it was a function of having a diversified supply. And what they were looking at was the relative cost of the ANR southeast which is more costly and that's why it's the source of last supply relative to the Oklahoma and minimized the amount of ANR

southeast and recommended more ANR southwest.
MR. KRIS SAXBERG: Centra hasn't filed any new evidence in this proceeding regarding its gas supply portfolio. And when I say "new evidence" I mean vis-a-vis the last hearing in September?
MR. HOWARD STEPHENS: Well, it seems like I was just here, sir, no, but, no, we have not supplied anything different.
MR. KRIS SAXBERG: And with respect to implementation of the IGC recommendations or the internal review, nothing's changed with respect to the status of that matter since the last hearing?
MR. HOWARD STEPHENS: That's correct.
MR. KRIS SAXBERG: And you're still on track for having the report completed August 1st?
MR. HOWARD STEPHENS: That's our evidence and that's our intention.
MR. KRIS SAXBERG: Can you commit on the record that there won't be any change to the portfolio at all without prior approval of the Board?
MR. HOWARD STEPHENS: Insofar as I've been directed by the Board not to change the portfolio without their prior approval I think it's incumbent on me to follow that directive.
MR. KRIS SAXBERG: And do you expect that

the internal review is going to be considered at the next cost of gas hearing which, I think you've indicated, is going to be filed in early January 2006?

MR. HOWARD STEPHENS: All I've suggested is that we will file the report no later than August 1st of this year. What the Board chooses to do with that report is the purview of the Board and I will not presuppose or try to second guess what they will choose to do with it.

MR. KRIS SAXBERG: Have you finalized your recommendation with respect to the -- when I say "your", I mean you as an individual drafting -- working on the report, have you finalized your recommendation?

MR. HOWARD STEPHENS: My individual or personal recommendation I don't think is relevant. It's a corporate decision. There are a variety of factors at play. Certainly I have an opinion but I don't think it's relevant to these proceedings.

(BRIEF PAUSE)

MR. KRIS SAXBERG: With respect to the potential benefits of moving to the optimized portfolio, your evidence yesterday was that the real benefit is security of supply.

MR. HOWARD STEPHENS: Actually I think Mr. Warden led that, I may have followed up with it, but, yes that's the general benefit associated with the recommendation that I do seek.

MR. KRIS SAXBERG: And there has been information on the record that there's also a potential economic benefit of approximately $2 million a year, is that correct?

MR. HOWARD STEPHENS: That's on the basis of the analysis that IGC did, yes.

MR. KRIS SAXBERG: And it's the case that that estimate could be a higher amount of savings or a lower amount, is that right?

MR. HOWARD STEPHENS: It could be either a higher or a lower and as some of the analysis that we're doing right now a sensitivity analysis in terms of what happens if things like TransCanada indeed gets -- becomes de-contracted or their tolls climb significantly.

And what happens if basis differentials move significantly as a result of LNG coming into the marketplace in the south or we have Northern Gas coming on from the north and those necessary requirements, I mean to deal with the broker community.

I mean there's a variety of issues that I've got to address with respect to this portfolio review and make sure that we have the flexibility to accommodate all of them.

So it's taken some time and more time than I had anticipated, but, it has taken some time to try to move through all of those issues and make sure that we're addressing them appropriately.

MR. KRIS SAXBERG: Your analysis is going to go beyond the four (4) corners of the IGC report and it's going to consider current market circumstances?

MR. HOWARD STEPHENS: I mean and there's no question, Mr. Saxton or Saxberg, I'm sorry --

MR. KRIS SAXBERG: That's okay, I've been called worse.

MR. HOWARD STEPHENS: That may be by me in a minute. Excuse me for that, I'm getting warm.

The point I wanted to make was that what we saw, in terms of the recommendation from ICG is not necessarily going to be the be all and the end all and in the final analysis the portfolio that we may ultimately end up with.

Because I mean over the course of the time horizon that they provided, the environment can change so significantly that the solution that they've come to may be not the best fit for Manitoba and Manitoba Hydro.

I think that there are some fundamental

things in their report that are substantive and I would agree with. But, there are other aspects of it that we will look at when we get more closely to the time that the ANR contracts are set to expire.

MR. KRIS SAXBERG: Thank you for that. As we sit here today, your evidence is that the status quo, in terms of the portfolio isn't so bad for now?

MR. HOWARD STEPHENS: We're able to serve our customers, we've had no difficulty serving our customers, we've served the interruptible load. I looked at our overall score card in terms of our utilization factor of the pipeline, our balance and fees and those were all the key indicators of performance, in terms of how we manage our assets.

And from that perspective, I think that the customers -- I have no difficulty, in terms of representing that we are providing good value for our customers.

MR. KRIS SAXBERG: And the internal review is going to propose ways to improve upon the portfolio?

MR. HOWARD STEPHENS: That's correct.

MR. KRIS SAXBERG: The system supply volumes seem to be trending downward, would you agree with that?

MR. HOWARD STEPHENS: Well, only by virtue of the fact that we have had, we have seen an increase in the number of customers that have elected direct purchase option, so the WTS mechanism.

MR. KRIS SAXBERG: That and also I guess there would be a factor for conservation?

MR. HOWARD STEPHENS: Yes, that's -- you're quite correct in that.

MR. KRIS SAXBERG: If that trend continues and accelerates, that definitely does impact the usefulness of the IGC report?

MR. HOWARD STEPHENS: Well, that factor as well as any demand side management program will also have an impact, so I mean those are just another couple of considerations that we have to be mindful of when we're developing what will be ultimately the final portfolio.

MR. KRIS SAXBERG: Would it be useful then, from your perspective, to have all of the various reports that are being undertaken by Centra right now, considered concurrently in one -- by the Board, so that they're looking at the impacts of all the reports together before determining what to do with any one of them?

MR. HOWARD STEPHENS: You're looking to

get me in trouble again, sir.

(BRIEF PAUSE)

MR. DARREN RAINKIE: Mr. Saxberg, I think page 30 of Order 131/04 is instructive and there's only two (2) lines on that page. Perhaps I'll read it:

"Centra require a Board approval before committing to any changes or issuing any calls for proposals. The Board will determine whether a public hearing or some other process is necessary."

I think we should let the reports come in and the conclusions be drawn and then the Board can go about its normal business of deciding what the next step is.

I'm not sure of the value in sitting here and -- and trying to figure out what the process should be at this point.

I mean, we've answered this question, I think, three (3) or four (4) times in the last two (2) days.

MR. KRIS SAXBERG: I just wanted the company's position as to whether all these reports are interrelated; are they?

(BRIEF PAUSE)

MR. HOWARD STEPHENS: Yes, to a great degree there is a strong inter-relationship with respect to a number of the reports that we are providing to the -- to the regulator.

MR. KRIS SAXBERG: Will the reports provide commentary on that inter-relation and how each report impacts on the other?

MR. HOWARD STEPHENS: I can only speak on behalf of the reports that I'm going to prepare and certainly I will try to identify what risks associated with a certain course of action would be.

What the content of the others are, I can't -- I can't speak to them.

MR. KRIS SAXBERG: So would you agree that that would -- that may be helpful to the Board and to -- to stakeholders in looking at these reports, may be helpful to know the company's perspective on how they all relate to one another?

MR. HOWARD STEPHENS: Yes, but I don't think I committed to giving that.

MR. DARREN RAINKIE: Mr. Saxberg, I think that's why it's important to wait and see the reports before we start making conclusions in that regard.

MR. KRIS SAXBERG: And just a couple of quick items. On -- with respect to UFG, has there been any further study of that 45 percent portion which is unknown?

MR. DARREN RAINKIE: Not to my knowledge, Mr. Saxberg, no.

MR. KRIS SAXBERG: And the Board had recommended that there be some further consideration of that -- of that percentage, and that's on page 49 of Board Order 131/04.

Are there any plans underway to do that?

MR. DARREN RAINKIE: Not to my knowledge. I don't think it was a firm directive, I think it indicated that we might want to consider that further.

I think our position has been, and was at the last hearing, that we did a fairly exhaustive study on that and that the nature of unaccounted for gas is -- is such that you can't figure out 100 percent where it goes.

MR. KRIS SAXBERG: There's a reduction afforded to one of the Intervenors at the last year's proceeding and the costs were passed on, the UFG costs were passed on SGS and LGS; correct?

MR. DARREN RAINKIE: Mr. Saxberg, I can't recall exactly where the differential of the percentage went, if it went to all the other customers. Certainly a portion went to SGS and LGS. I can't remember if it was the entire differential or not.

MR. KRIS SAXBERG: My recollection was that the Board ordered that that differential only be picked up by SGS and LGS on the basis that those two (2) classes have the most meters with the lowest accuracy.

MS. MARLA MURPHY: Perhaps, Mr. Chairman, this could be dealt with when Ms. Derksen is present on the third Panel and is able to speak to the allegation that was made.

THE CHAIRPERSON: Makes sense to me.

Mr. Saxberg...?

MR. KRIS SAXBERG: Yeah, that's a good idea.

CONTINUED BY MR. KRIS SAXBERG:

MR. KRIS SAXBERG: With respect to the exchange rate, the original application had an exchange rate calculated at Tab R of my book of documents of one thirty-three (1.33), correct?

MR. BRENT SANDERSON: That's correct.

MR. KRIS SAXBERG: Would you undertake to provide a calculation of how the new exchange rate of one, twenty-three (1.23) was determined in the same form as you have done at my Tab R of the book of documents?

MR. BRENT SANDERSON: Are you referring to the internal process at Manitoba Hydro to determine that forecast?

MR. KRIS SAXBERG: Well, when the application was filed you were using one (1) exchange rate; correct?

MR. BRENT SANDERSON: That's correct.

MR. KRIS SAXBERG: And the Intervenors asked questions about how you came up with that number because it has a significant effect; correct?

MR. BRENT SANDERSON: It's a relevant input to the gas cost forecast.

MR. KRIS SAXBERG: And so now we've got a new number that's been put forward, I think when the application was updated; correct?

MR. BRENT SANDERSON: Yes, that's correct. And if you might just give me a second, there was an IR that the Corporation responded to in that respect explaining the details behind how we arrived at that new forecast figure of one, twenty-three (1.23); if you'd just give me a moment?

(BRIEF PAUSE)

MR. BRENT SANDERSON: CAC/MSOS/Centra/131 enquired into what the updated exchange rate forecast would be in the pre-hearing update to our application and provides some scenarios around what different exchange rates would have resulted in terms of an overall annual gas cost impact and identifies the exchange rate used in the updated forecast.

Are you looking for something beyond that?

MR. KRIS SAXBERG: I'm just looking for Centra -- CAC/Centra/61 to be updated -- the second page table?

MR. BRENT SANDERSON: We can undertake to provide that.

MR. KRIS SAXBERG: Great.

--- UNDERTAKING NO. 4: Centra to provide CAC/MSOS the updated second page table of CAC/MSOS/Centra-61.

CONTINUED BY MR. KRIS SAXBERG:

MR. KRIS SAXBERG: And, finally, Mr. Stephens, with respect to TCPL tolls, because of the interim tolls approved there's a reduction of $1.8 million to the benefit of consumers; correct?

MR. HOWARD STEPHENS: Relative to our

original application, yes.

MR. KRIS SAXBERG: And then the -- there was an award -- an increased equity portion for TCPL and that's going to have what you said was a relatively minor impact on this proceeding; correct?

MR. HOWARD STEPHENS: Yes, because as a part and parcel of setting the new July 1st, 2005 interim tolls -- or they're going to be filed, I've lost track, there is an offsetting amount with respect to the discretionary revenues that they've incurred -- or generated that will somewhat offset the impact, if not fully impact the offset.

MR. KRIS SAXBERG: Right. And that's -- that's all I wanted to know was, you hadn't indicated whether that $1.8 million is going to be somewhat lower or somewhat higher as a result?

MR. HOWARD STEPHENS: Assuming the NEB approves what is being proposed, it would actually be a reduction from the tolls that are currently in our application. Very small reduction, but a reduction nonetheless.

MR. KRIS SAXBERG: Okay. And any difference is going to be reflected in deferral account anyway?

MR. HOWARD STEPHENS: That's correct.

MR. KRIS SAXBERG: Okay. Thank you very much. Those are all my questions.

THE CHAIRPERSON: Thank you Mr. Saxberg.

Ms. Melnychuk do you have any questions?

MS. KAREN MELNYCHUK: No, we do not.

THE CHAIRPERSON: Thank you. I notice Mr. Miller's not here.

Ms. Murphy, do you have any re-examination?

MS. MARLA MURPHY: No I do not. However, I do have one (1) housekeeping matter, Mr. Chairman. I circulated just after the break a discussion paper entitled, Advantages and Disadvantages of Centra Offering Multiple Services Products.

And just before we break, I'd like to have that marked as an Exhibit if I could. By my list it would be Centra Exhibit 9.

THE CHAIRPERSON: Subject to check, Exhibit 9. Thank you.

--- EXHIBIT NO. CENTRA-9: Discussion paper entitled, Advantages and Disadvantages of Centra Offering Multiple Services Products

MR. BOB PETERS: Speaking of Exhibits, Mr. Chairman, Mr. Saxberg may want to address with Ms. Murphy whether the Book of Documents that CAC/MSOS prepared is marked -- left marked as Exhibit 'A' or does it -- for identification or be provided with an Exhibit number in the proceedings and we should tidy that up before lunch as well.

THE CHAIRPERSON: Ms. Murphy, have you changed your view?

MS. MARLA MURPHY: Not really, Mr. Chairman, I think I've made my views on that fairly clear. I guess as a suggestion, perhaps those two (2) tabs could be removed from the book and it could be marked or I'll leave it to the Board to decide, in terms of the weight that's accorded to those items.

THE CHAIRPERSON: I think we'll leave it to the Board to give it its proper weight. We'll mark it, I think it's number 3, Mr. Saxberg?

--- EXHIBIT NO CAC/MSOS-3: Book of documents, previously marked as CAC/MSOS-A

MR. KRIS SAXBERG: Yes, I believe.

THE CHAIRPERSON: And the Board will note those two (2) particular items, I think it's 'N' and 'P', okay, will be provided to the Board that the weight comes to the conclusion it deserves.

Thank you very much.

MS. MARLA MURPHY: I just have one (1) final matter, I'm sorry --

THE CHAIRPERSON: Yes --

MS. MARLA MURPHY: -- I was handed a response to Undertaking number 3, so if you're prepared to have it, we could have it filed now.

THE CHAIRPERSON: Let's do that.

MS. MARLA MURPHY: It would be, I believe, Exhibit number 10, Centra's Exhibits.

THE CHAIRPERSON: Mr. Singh?

--- EXHIBIT NO. CENTRA-10: Response to Undertaking No. 3

THE CHAIRPERSON: Mr. Peters, while we're waiting for that to be distributed, do we have anything else to deal with today?

MR. BOB PETERS: We do not, Mr. Chairman, I'll just remind the parties that we will convene Monday next, 9:00 a.m., commence with the Revenue Requirement Panel.

I should also perhaps put on the record

that Ms. Ruzycki indicated to me at the break that she'd be slipping away just a few minutes before noon and she's done that.

But, indicated that the questions that she had of this Panel had already been asked and answered. And therefore she appreciated the opportunity to make earlier travel arrangements in light of the schedule.

THE CHAIRPERSON: Thank you, Mr. Peters. I believe that number 10 has now been circulated to all the parties. So we will stand adjourned until next Monday morning, thank you.

(PANEL STANDS DOWN)

--- Upon adjourning at 12:00 p.m.

Certified Correct,

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Carol Wilkinson, Ms.