MANITOBA PUBLIC UTILITIES BOARD

Re: CENTRA GAS
COST OF GAS APPLICATION

Before Board Panel:

Graham Lane	- Board Chairman
Monica Girouard	- Board Member
Mario Santos	- Board Member

HELD AT:

Public Utilities Board
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APPEARANCES

R.F. Peters	)Board Counsel
Marla Murphy	)Centra
Kris Saxberg	)Canadian Association of Consumers, Manitoba Society of Seniors (CAC/MSOS)
Bill Carroll	)MacDon Industries Ltd.
David Brown Karen Melnychuk	)Municipal Gas/Direct Energy
Carol Wilkinson	)Court Reporter

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--- Upon commencing at 8:03 a.m.

THE CHAIRPERSON: Good morning everyone. I hope everyone enjoyed the hockey game last night.

The -- today we have another busy day. To begin with we'll be introducing Centra's Witness Panel Number 2. Ms. Murphy, do you want to introduce them and then I'll have Mr. Singh provide the oath, or the affirmation.

MS. MARLA MURPHY: Certainly. Good morning, Mr. Chairman, members of the Board, ladies and gentlemen. A couple of the faces have changed on our panel, Mr. Stevens and Ms. Stewart having been excused.

We now have joining our panel, Ms. Kelly Derksen, who is the Senior Analyst of gas rates and Mr. Greg Barnland, who is the Senior Consultant, gas rates and policy. Just running down the roster from start to end, Mr. Warden is on my immediate right, Vice President, Finance and Administration and Chief Financial Officer.

And on Mr. Barnlund's right is Greg Sanderson -- sorry, Brent Sanderson, Senior Gas Cost and Hedging Analyst. And Mr. Dan Rainkie, who is the Manager of Gas Rates Regulatory Services.

The Panel has, for the most part, been sworn other than Ms. Derksen and Mr. Barnlund. Our intention on the Board's process, was to have Ms. Derksen give her direct evidence this morning, which relates to cost allocation matters and rate design, the 'H' -- the 'F' issues.

Mr. Barnlund and Ms. Derksen, will give direct evidence tomorrow, as it relates to the unaccounted for gas issues.

And if I might, I just have one (1) more housekeeping matter. You would have found on your chair this morning, an attachment PUB/CENTRA 8(a), Attachment 4, this is the most recent minutes of the gas supply risk management committee, which were approved and would form an attachment to the response to IR-PUB/CENTRA 8(a).

That IR has been given an Exhibit number PUB-5-8 and I might suggest that this simply be attached to that IR and form part of that exhibit.

THE CHAIRPERSON: That's fine. Thank you. Mr. Singh?

KELLY DERKSEN, Sworn;
GREG BARNLAND, Sworn;

THE CHAIRPERSON: Thank you and welcome. Ms. Murphy...?

EXAMINATION IN-CHIEF BY MS. MARLA MURPHY:

MS. MARLA MURPHY: Thank you. Ms. Derksen, would you please outline your areas of responsibility with respect to this Application?

MS. KELLY DERKSEN: Good morning, Mr. Chairman, Members of the Public Utilities Board, ladies and gentlemen. In my testimony, I will be providing evidence related to the 2004/'05 Cost Allocation Study and the allocation of the non-primary PGVA and gas cost deferral account balances as at March the 31st of 2004.

I will also be providing evidence with respect to the allocation of unaccounted for gas and the billing of high volume firm demand charges and the proposed changes to the terms and conditions of service.

MS. MARLA MURPHY: Ms. Derksen, could you please outline for the Board the rate impacts of Centra's Application on customers?

MS. KELLY DERKSEN: The billed rates that are proposed for November 1st, 2004 result in a typical residential customer's bill decreasing by approximately 3.9 percent or fifty-two dollars ($52) per year.

The annual bill impacts for the LGS class range from decrease of 2.8 percent to 3.4 percent. The high volume firm class impacts, which were revised on September the 2nd, now range from a decrease of 7.2 percent to 8.5 percent.

The main line customer class will experience a decrease of 4.2 to 6.3 percent. And the interruptible class will experience an increase of 1.2 to 1.4 percent. The special contract customer will experience a rate decrease of 19.3 percent and the power stations will experience an increase of 13.2 percent. The annual bill comparisons are relative to the approved August 1st, 2004 billed rates.

MS. MARLA MURPHY: Ms. Derksen, could you please describe the purpose and process of a cost allocation study?

MS. KELLY DERKSEN: A cost allocation study is designed to estimate the cost to provide a specific service to a particular customer or class of customers. The cost allocation process is a three (3) step sequential process consisting of functionalizing the costs into broad -- broadly defined groups, which describe the purpose or the function of those costs, classifying the costs on the basis of their variability and finally allocating the costs to the various customer classes.

The cost allocation study also provides information on the nature of the costs, whether those costs are fixed or variable and the factors that affect the variability of costs.

This information is beneficial in terms of determining an appropriate rate design, again assuming that rates reflect the costs incurred.

As such, the cost allocation study provides the basic data upon which rates are based.

MS. MARLA MURPHY: Ms. Derksen, is the cost allocation methodology used in connection with this Rate Application consistent with that used in previous Applications?

MS. KELLY DERKSEN: Yes. Centra is not proposing any substantial changes in its approach to cost allocation in this Application. Centra has completed a review of unaccounted-for gas which will impact its allocation in the Cost Allocation Study.

MS. MARLA MURPHY: And would you please outline the rate riders that Centra's proposing in this Application?

MS. KELLY DERKSEN: Centra proposes to refund approximately $16.5 million in rate riders to customers in this Application. Schedule 8.4.0 updated, summarizes the allocation of the non-primary PGVA and gas cost deferral accounts as at March the 31st of 2004, with carrying costs to October 31st of 2004 to the various customer classes.

As a result of the timing of this gas cost proceeding, Centra anticipates new rates be approved for November the 1st, 2004.

Centra is therefore proposing to refund the approximate $16.5 million over a nine (9) month period, ending July the 31st of 2005. This allows the expiry of the proposed rate riders to coin -- to coincide with the customary implementation of annual non-primary gas rate changes on August the 1st of 2005.

MS. MARLA MURPHY: Ms. Derksen, can you please explain Centra's proposal for the refund of the supplemental gas PGVA?

MS. KELLY DERKSEN: Centra is proposing to refund the supplemental PGVA balance through the distribution to customer charge for all customer classes except the mainline class.

Centra is proposing a separate line item on the bill for the four (4) mainline customers who receive supplemental gas from Centra, because refunding the supplemental PGVA in their distribution to customer charge results in a negative billed rate.

Centra has proposed this change to deal with the volatility in the supplemental gas rate that results from the large refund that has accumulated in the supplemental gas PGVA.

Centra's concerns with respect to the volatility in the supplemental gas rate were discussed in the update to the Application filed with the PUB on August the 9th.

Refunding the supplemental PGVA in the

distribution to customer charge allows for a more correct price signal to customers on the cost of supplemental supply, while ensuring that the refund is provided to the appropriate customers. As well, the supplemental PGVA will be refunded over total sales volumes in the distribution to customer charge, thus allowing for a smoother refund of the supplemental PGVA.

MS. MARLA MURPHY: Ms. Derksen, what is Centra seeking with respect to amendments to the terms and conditions of service?

MS. KELLY DERKSEN: Centra is proposing amendments to the terms and conditions of service as outlined in Tab 9 of the Application. A number of these changes are made to ensure consistency of the Board Orders and the letters with the actual terms and conditions of service, including amendment to the service territory, WTS and ABC terms and conditions, standard pressure and temperature and removal of references to the buy/cell service.

In addition, Centra is proposing amendments with respect to the company labour rate, such that the terms and conditions of service would specify cost based rates, depending on the nature of the work performed, rather than specifying a rate with -- which is no longer representative of the services rendered.

This will bring Centra’s labour rates in line with those charged by Manitoba Hydro and reflect the integrated cost allocation -- cost accounting methodology incorporating the labour activity rates which included -- includes wages, benefits, vehicles and tools.

The customer will be advised of the cost through an estimate that is provided to them prior to the commencement of any work performed.

Centra is also seeking amendments with respect to the temporary disconnection charge which is currently stated as two hundred and twenty dollars ($220) in the miscellaneous charges for service.

Because the cost to temporarily disconnect and then subsequently re-establish service can vary depending on the size of equipment -- equipment reinstalled, Centra proposes to amend the two hundred and twenty dollar ($220) rate to be a cost based fee for re-establishing the natural gas service.

This fee is expected to range from a hundred and twenty-five (125) to three hundred dollars ($300) for typical residential customer. Centra has also seeking to amend the miscellaneous charges for service to clarify that there are a number of situations in which customers request both relocations and alterations of the meters, regulators and service lines.

Centra is adding alterations to this part of the terms and conditions of service. This change ensure that terms and conditions of service are consistent with Centra’s practices and allows Centra the ability the charge customers for the cost of requested work, such that other ratepayers are not absorbing the cost of these changes.

Finally, Centra is seeking to amend the miscellaneous charge for service, which relate to service reinstallation policy. When a service re -- when a service abandonment request is received, Centra will remove the meter, regulator and in some cases, the service line.

Centra wishes to charge the customer for the full cost of installation of the new service line meter and regulator, should the same customer request re-installation within five (5) years.

The proposed amendments includes reference to the service line which has not been included in the past. And as noted in the response to PUB/Centra 35, Centra’s no longer proposing to amend the cost of labour for the SGS non-residential customers related to safety services.

MS. MARLA MURPHY: Ms. Derksen, what is Centra proposing in this Application with respect to the high volume firm billing demand?

MS. KELLY DERKSEN: What Centra is proposing in this Application with respect to the high volume firm demand is that Centra is requesting PUB approval to bill high volume firm demand charges on the basis of actual peak day, commencing on November the 1st of 2004.

And we have incorporated actual peak day billing units as part of the dem -- the demand rates determination.

MS. MARLA MURPHY: Ms. Derksen, can you please explain how the demand ratchet is determined?

MS. KELLY DERKSEN: Demand for the purposes of set -- of billing is set only during the winter months of November to March. No demand is set during the summer months of April to October.

Demand is billed to customers based on the highest daily consumption between November and March, except for the high volume firm class who is currently billed on the average of the daily consumptions of the peak months.

Once demand is set a customer will be billed demand on this consumption level for the next eleven (11) months unless a customers daily consumption is exceeded during a winter period.

If demand is not exceeded during the next eleven (11) months, Centra will re-establish demand for a customer on the basis of the prior highest daily consumption of the past eleven (11) months, so long as it is a winter month.

MS. MARLA MURPHY: Can you explain Centra’s proposal for the implementation of billing demand for the high volume firm class on November 1st, 2004?

MS. KELLY DERKSEN: Yes. Centra's proposing a slightly different implementation of billing demand compared to how a ratchet -- a demand ratchet is typically set and as how I previously described.

If Centra's proposal is accepted, rather than setting demand on the basis of the 2003/'04 peak that was set last year, Centra will continue billing each customer based on the average of the peak month for this class, until the customer exceeds the average peak.

Last year 60 percent of customers in the high volume class exceeded their peak in November. This implementation proposal allows high volume firm customers to make changes to their load profile if they wish to avoid being billed on their actual 2003/'04 peak.

Centra has proposed this implementation solely to ease the transition for the high volume firm of customers.

MS. MARLA MURPHY: Ms. Derksen, why does Centra believe that billing demand on the basis of actual peak day is an appropriate billing methodology?

MS. KELLY DERKSEN: The cost that Centra incurs to provide service to customers are classified into three (3) broad categories; customer related, capacity related and commodity related.

The capacity related costs include the costs of providing upstream transportation and downstream transmission and distribution capacity to serve the peak load. These costs are fixed in nature as they are a function of the size of the peak load that must be served and do not vary with the changes in the total volume of natural gas consumed by a customer.

Capacity related costs are recovered largely through the monthly demand charges. It is appropriate to bill and recover the capacity costs that have been allocated to the high volume from class from each of the individual customers in that class on the basis of actual peak day for the following reasons.

The first is to encourage high load factory usage of Centra’s system. Number two (2) is to reflect the nature of costs incurred to provide service to customers, to have actual peaks that are observable and directly controllable by the customer and to have demand that is consistently charged for all customers with three (3) part rates.

The use of actual peak day to bill and recover capacity costs is superior to the use of average demand as it more accurately measures the maximum draw of the customer on the system which is consistent with how those capacity costs are incurred.

Average demand is a function of the total usage during the month, rather than peak usage on the system. This is the reason that actual peak is used as the basis of billing of demand costs in the other high volume -- high volume customer classes and is the reason that it should be used for the high volume firm class as well.

Centra wishes to remedy this situation by moving to billing the high volume firm demand costs on the basis of actual demand on November 1st of 2004.

MS. MARLA MURPHY: Ms. Derksen, what is Centra's proposal to deal with the billing difference that arose from August 1st, 2003 to February 29th, 2004?

MS. KELLY DERKSEN: The PUB indicated in Order 16/04 that the implementation of actual demand billing methodology and associated demand rate should be delayed until after the winter demand seasons of 2003/'04 that ended on March the 31st of 2004.

Therefore, implementation of actual demand billing and the associated rate was to occur on or after April the 1st of 2004.

The demand rate that was put on play -- in place last August of 2003 was in effect for seven (7) months until the end of February of 2004. Under Centra's implementation proposal, the revised demand rate will be in effect until October the 31st of 2004 and as such, the revised demand rate will be in effect for seven (7) months after April the 1st of 2004.

It is Centra’s position that the demand rate differential from August the 1st of 2003 until February the 29th of 2004 for the most part is offset by the further delay in the implementation of actual demand billing and the associ -- the associated rate to November 1st of 2004 and as such, there is no need to revise the high volume firm demand billings for the earlier period.

This would mitigate against the potentially severe negative customer response resulting from issuing a retroactive bill to more than forty (40) customers in the high volume firm class for the period of August the 1st of 2003 until February the 29th of 2004.

MS. MARLA MURPHY: Thank you, Ms. Derksen. Mr. Chairman, that concludes the direct evidence of this Panel, apart from the UFG evidence that will be heard later.

THE CHAIRPERSON: Thank you, Ms. Murphy. Rather than going on now to Board Counsel to begin the cross-examination, we’re scheduled to receive a presentation from Mr. MacDonald of MacDon Industries. Is Mr. MacDonald ready?

MR. BILL CARROLL: Yes.

THE CHAIRPERSON: Welcome and please proceed.

MR. ALLAN MACDONALD: Thank you sir. I would like to thank the PUB for the opportunity to attend here today. You have previously received our comments and questions in the form of a letter.

I must say that this has been a very frustrating experience for our small company, it started out by simply questioning the timing of a proposed change to the status quo last fall. In the intervening months it grew into a much larger topic. The questions beget more questions and in particular as to the process.

There is no way that we could have stayed the course and still be here today without help. That assistance came in the form of a consultant, as you are aware, Mr. Bill Carroll, on my right. I know that he will have his own comments and questions later today.

I cannot believe that some of the information and data that eventually is used to make rulings can be suspect. Surely there should be no debate as to how a set of numbers was calculated. One might not agree with the conclusion, but the process should be clear and concise and correct.

Our frustration is compounded, when the general impression in the public domain is fuzzy, like a bear. The notice in regards to this set of Public Hearings, suggests to the casual reader, that we are looking at a reduction. We know from a recent set of proceedings, that the PUB very well may decide to increase the request from

Centra.

We could once again be blind sided by an even larger increase than that which we believe we are already facing at this time. To us, the lines between the Utility providers and the PUB are blurred.

Our faith in the system is shaken, and I cannot tell my brothers and/or employees, that all is well on this topic.

We are already in an industry that is reeling from the BSC or Mad Cow Disease. We now have a late wet harvest on the prairies, we employed several additional people this spring, and have some exciting new products coming out of engineering.

Whether we build the increased volumes and the jobs that they will bring here in Winnipeg, or somewhere else, is now suspect. We will need to review our options as to any future plant expansions as to location.

When we added on to our production facilities in the year 2000, we felt that with the cost of energy in Manitoba, we made a good choice. We spent approximately $20 million on that expansion, to increase our capacity and introduce newer and friendlier technology.

We recently added another facility to help bring potential customers to Winnipeg. We are proud to be Winnipeg and Manitoba based, and wish to remain so. This process that we're going through makes it harder to do so. Thank you for your time.

THE CHAIRPERSON: Thank you, Mr. MacDonald. Now, following our normal process we'll return to Mr. Peters.

MR. BOB PETERS: Yes, thank you. Good morning, Mr. Chairman and Board Members.

I'd also like to thank Mr. Carroll and his client, Mr. MacDonald, for coming forward with their presentation.

As the Board is aware on August the 31st, Mr. Carroll submitted a written presentation on behalf of his client, and that has been copied to registered Intervenors and the Board has -- has a copy as well.

My suggestion, Mr. Chairman, similar to what we did in previous presentations in this Hearing, is that we ask our court reporting service to embed that presentation in the transcript of proceedings today, so that we have the presentation in the transcript.

THE CHAIRPERSON: That's fine.

MR. BOB PETERS: All right, thank you. With that, Mr. Chairman, I'll turn to the Panel this morning.

CROSS-EXAMINATION BY MR. BOB PETERS:

MR. BOB PETERS: And perhaps, Ms. Derksen, I'll begin with you. Good morning and welcome.

As I understood what you told your lawyer this morning, the principle goal of rate setting is to establish rates that are -- you consider fair and equitable and not unduly discriminatory?

MS. KELLY DERKSEN: That's true.

MR. BOB PETERS: And that's why you use a cost allocation study is to further that goal?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: Would a -- would the Board be correct in understanding that Centra considers the rates to be fair when they reflect the costs that are incurred to provide the service?

MS. KELLY DERKSEN: Yes, I would agree that that's been established as the -- the defined definition of fair.

MR. BOB PETERS: So, if rates reflect the costs incurred to provide the service, that in general terms is considered to be fair in regulatory parlance?

MS. KELLY DERKSEN: Yes. Certainly in -- as part of Centra Manitoba and in this jurisdiction.

MR. BOB PETERS: And you agree with me that rates can be different if there is a reasonable and rational basis for those differences?

MS. KELLY DERKSEN: Yes, I agree with that.

MR. BOB PETERS: And -- and one (1) of the reasons rates could be different would be the nature of the service provided?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And additionally, there could be a difference in rates if the costs in providing that similar service is also different between customer classes?

MS. KELLY DERKSEN: Yes, that's true.

MR. BOB PETERS: Now the cost allocation study that you perform, is it correct that that is to estimate the cost to provide specific service to specific customer classes?

MS. KELLY DERKSEN: Yes, that's what we do.

MR. BOB PETERS: And from your answers to Ms. Murphy earlier this morning, I take it that the significant change in your Cost Allocation Study over previous years is that you have a proposal related to unaccounted for gas and that's a matter that will be addressed tomorrow?

MS. KELLY DERKSEN: Yes, that's the major change this -- this go round.

MR. BOB PETERS: All right. And when you say the "major change", you're telling the Board that there aren't any other significant changes in the methodology or process; is that correct?

MS. KELLY DERKSEN: Yes, that's true.

MR. BOB PETERS: But of course the -- the numbers change from year to year, correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And in the updating filing that the Board received on August the 9th, I believe Mr. Sanderson told the Board that the non-primary gas costs were approximately $83.4 million. Is that where you started from in your cost allocation?

MS. KELLY DERKSEN: I don't -- $83.4 million is the amount that we are discussing as part of this Application. That's not necessarily where I start from. I look at all of the costs that make up that $83.4 million and ultimately I need to allocate costs to each of the customer classes that total $83.4 million.

MR. BOB PETERS: Ms. Derksen, in this Application you are not allocating any primary gas costs, are you?

MS. KELLY DERKSEN: We are not, Mr. Peters.

MR. BOB PETERS: And you are also not allocating what has been called non-gas costs?

MS. KELLY DERKSEN: That's true as well.

MR. BOB PETERS: And those non-gas costs are generally the matters that are subject of a General Rate Application. Would you agree with that?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: In the update that you

provided, Ms. Derksen, there was an update to your cost allocation and I take it that update was really just a correction or revision of some of the errors or mistakes that may have been seen from the first filing. Would you agree with that?

MS. KELLY DERKSEN: The information that we filed with the PUB on September 2nd; I would agree with that. The information that we filed on August the 9th was simply an update with respect to gas costs.

And so that's what the cost allocation incorporated as well.

MR. BOB PETERS: All right, thank you for that. And one of the revisions that was made was a volume adjustment for the special contract class; is that correct?

MS. KELLY DERKSEN: For the August the 9th updated filing, yes, I would agree.

MR. BOB PETERS: That August the 9th update to the special contract class does not impact the method of allocation, does it?

MS. KELLY DERKSEN: It does not affect what we have allocated in terms of a percentage of UFG to each of the customer classes; that's correct.

MR. BOB PETERS: And so while it doesn't impact the methodology that you used, for the particular class for which the volume was updated, that would impact on the numbers, in that class, correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And what I understand then to be that revision, is that the volumes in essence, increased and therefore the unit rates would have decreased?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And that's only for unaccounted for gas for the special contract class?

MS. KELLY DERKSEN: That the unit rate decreased as a result of unaccounted for gas costs, yes.

MR. BOB PETERS: Now, when the Board reviews the cost allocation, Ms. Derksen, the end result is that you provide the Board with a base rate and that's what you've included in these filings; is that correct?

MS. KELLY DERKSEN: Yes, that's true.

MR. BOB PETERS: And from your evidence the base rate that you have forecast, is to go into effect on November 1st of 2004, and it is to recover non-primary gas costs for a twelve (12) month period?

MS. KELLY DERKSEN: Yes, that's correct, with respect to the base rates.

MR. BOB PETERS: And when we say, base rates, Ms. Derksen, you're telling the Board that those are the base rates for supplemental gas, as well as, the transportation to Centra rate and the distribution to customer rate that will be set November the 1st?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And collectively, Ms. Derksen, the base rates that you are setting are approximately $3.4 million less or lower, on an annual basis, than the existing base rates; is that also correct?

MS. KELLY DERKSEN: Mr. Peters, I believe the number was $3.2 million less, but, we're very close.

MR. BOB PETERS: If I didn't say 3.2 million, Ms. Derksen, I apologize. I mis-spoke. In my notes here, I have $3.2 million as the -- as the amount of the -- the base rates are lower on an annual basis?

MS. KELLY DERKSEN: Yes, 3.2 million.

MR. BOB PETERS: In addition to the base rates being lower by $3.2 million on an annual basis, Ms. Derksen, you've also now told the Board that you have purchase gas and variance account balances and deferral account balances of approximately $16.5 million to refund to customers; is that correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And that $16.5 million refund relates to non-primary gas costs?

MS. KELLY DERKSEN: Yes, that's true.

MR. BOB PETERS: There's no inclusion in that $16.5 million of any monies on account of the primary gas?

MS. KELLY DERKSEN: That's correct.

MR. BOB PETERS: Would it be correct to say then that the $16.5 million that you are proposing to refund, is in essence an over collection of monies relative to the costs that were forecast and built into the rates from last year?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: Ms. Derksen, when it comes times to refund the $16.5 million, is it your goal to refund it to the customer classes that created the surplus of $16.5 million?

MS. KELLY DERKSEN: Yes, that's my goal.

MR. BOB PETERS: And can you tell the Board how you do that?

MS. KELLY DERKSEN: I've provided information on all of the deferral account balances as -- as at a certain date. In this case, it's March the 31st of 2004. And I then take that information and I reallocate that PGVA -- those PGVA balances to each of the customer classes, similar to how I allocate the base rate component.

So, I would start at functionalizing each of the costs that make up the PGVA. I would then classify those costs consistent with how I would classify the base component. And then I allocate it to each of the customer classes.

So, the PGVA balances are really treated very consistently with how the rates are established for the base components.

MR. BOB PETERS: I take from that answer, Ms. Derksen, that you use the same methodology to create the base rate as you do to refund the PGVA balances?

MS. KELLY DERKSEN: That's what I attempted to say, yes.

MR. BOB PETERS: Can the Board then take some comfort in that the customer class that created a certain dollar amount of that over collection of money will receive a refund of that amount that they've over collected?

MS. KELLY DERKSEN: That's what I attend to do, yes, Mr. Peters.

MR. BOB PETERS: All right. So, if the residential class ends up overpaying on account of some of the purchased gas variance accounts that are created, and there is cert -- a positive balance reflecting moneys owing to consumers, you then will refund that in the same proportion that the class created it back to the class?

MS. KELLY DERKSEN: That's true.

MR. BOB PETERS: Would you agree with me, Ms. Derksen, that there is a certain level of imprecision in that methodology, in the sense that there may be customers that helped create the PGVA, but they are no longer on the system?

MS. KELLY DERKSEN: Yes, sir, and what I think you're referring to is what I would typically call inter-generational issues, where certain -- certain sets of customers caused for those balances to be incurred, or to be accumulated on their behalf, but it's not necessarily those same customers that benefit or have to pay back for those balances.

MR. BOB PETERS: Would you agree though, that it also works from the perspective of -- it works from both directions. That is if the balance ends up being one that has to be recovered from consumers, it works just in the -- in the same -- in the same methodology?

MS. KELLY DERKSEN: Yes, if we owe monies to customers, we have the same problem, although I wouldn't -- I don't know if I'd call it a problem. It sounds like we have this huge issue on our hands; we -- we really don't.

But for sake of argument, we would have the same problem if we owed monies to customers or if customers owed us money.

MR. BOB PETERS: The net cause of that, what we've talked about is a -- a problem or a concern then, Ms. Derksen, is that you have on a regular basis, customers attaching to the system as well as customers leaving the system?

MS. KELLY DERKSEN: That's true, Mr. Peters.

MR. BOB PETERS: And if customers leave the system there's no attempt made to find them or follow them or track them, for the purposes of either refunding them money or collecting money from them?

MS. KELLY DERKSEN: That's correct.

MR. BOB PETERS: And you only refund or collect from customers attached to your system, as of the time that the refunds or collections go into affect?

MS. KELLY DERKSEN: That's correct.

MR. BOB PETERS: Ms. Derksen, when we talk about base rates, it is not always the case that consumers will see on their monthly bills the base rates that the Utility is charging, would that be correct?

MS. KELLY DERKSEN: That is correct. What the consumer sees on the bills is a combination of the base rate, which sets -- is based on the forecasted, in this case, the cost of gas for the upcoming '04/'05 year, and added to that would be the rider component.

So, at the end of the day what the customer sees is a billed rate rather than just the base component.

MR. BOB PETERS: All right. From that answer you're telling the Board then that the billed rate is made up of generally two (2) parts; that is the billed rate is made up of the base rate, plus the rate riders that are attached to it.

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And those rate riders can be either recovering moneys from consumers or refunding moneys to consumers; is that also correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And I think Mr. Rainkie told us that in -- in his short experience or maybe long experience, we are currently under a situation where the rates in Manitoba to gas consumers, that is where the billed rate is actually equal to the -- to the base rate, because there's no rate rider attached currently?

MS. KELLY DERKSEN: Effective August 1st, 2004, Mr. Peters, we removed all of the rate riders off of the -- of all of the rate components, and so the answer to the question is yes.

MR. BOB PETERS: And you're now telling the Board you want to put another rate rider on and include it in the billed rates and that is to refund the $16.5 million that you have in surplus position on the PGVAs?

MS. KELLY DERKSEN: Yes, I would. I would call them rate riders, because there are a number of them, but yes.

MR. BOB PETERS: The distinction you just made, Ms. Derksen, is you're telling the Board that there's not just one (1) rate rider, but there will be multiple rate riders for the various components of the non-primary gas costs?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: Ms. Derksen, I heard you to tell Ms. Murphy that you wanted these rate riders refunding the $16.5 million to refund that money by July 31st of 2005.

MS. KELLY DERKSEN: Yes, Mr. Peters, that's correct and I just wanted to make a clarification of my last answer. Recognizing that there are some PGVA accounts as part of this Application that we have due -- owe --owing to customers, some of them though, are amounts owed to the company, so on the net amount -- the net accumulation of all of the PGVAs is $16.5 recognizing that there are some pluses and minuses within that balance.

MR. BOB PETERS: And -- and the detail of that was provided, I think you told us, on Schedule 8.4.0 updated.

MS. KELLY DERKSEN: I think it's both on 8.4.0 and 8.5.0, Mr. Peters.

MR. BOB PETERS: All right, thank you. We have that, Ms. Derksen. But I just want to take you -- and explain to the Board, what's going to happen on August the 1st of next year, because under your proposal and let's assume that all things are being equal, Ms. Derksen, would the Board then -- well, explain to the Board what would happen on July 1st from your perspective.

MS. KELLY DERKSEN: What would happen on --

MR. BOB PETERS: Sorry, August 1st, 2005.

MS. KELLY DERKSEN: What would happen on August the 1st of 2005, all things being equal, would be similar to what happened this year on August the 1st of 2004 and that is all of the riders would be -- would be removed off of -- out of the base -- or out of the billed rate and we would be just billing the base component as of -- as at that date.

Presumably, though, there would be some kind of gas cost application or filing that we would be undergoing at -- at that point that may include put -- putting new riders on for the -- for the next upcoming year.

MR. BOB PETERS: And you told me all things are equal, then you changed it. You -- you didn't keep all things equal for me, Ms. Derksen. But, let's just cover your last point first, that you -- you told Ms. Murphy that you expect for next August the 1st that you will have had an Application before this Board and you will be asking this Board to put new August 1st rates in effect for non-primary gas costs?

MS. KELLY DERKSEN: I can't guarantee it, but that's likely what's -- what's been happening over the course of the last number of years, so, yes.

MR. BOB PETERS: All right. Now back to my scenario where all things are, in fact, equal. You've told the Board that you would remove the rate riders and you would be left then with only base rates on August the 1st of '05. Would that be correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And if the consumer is sitting in their home and getting your -- your bills monthly, the consumer would not have in their billed rates any more rate riders that are refunding them money, so in essence to the consumer, it would appear as though the billed rate would increase. Would that be correct?

MS. KELLY DERKSEN: That would be the perception, again, keeping in mind that there would be some negative riders to come off and some positive riders to come off. On balance, the overall impact would be an increase to the customer at that time.

MR. BOB PETERS: On an annualized basis, Ms. Derksen, that increase to your consumers would equate to a net basis of $16.5 million; is that correct?

MS. KELLY DERKSEN: All -- all things being equal, yes.

MR. BOB PETERS: And -- and again, with all things being equal, which means no more gas applications along the way, that $16.5 million increase equates to approximately a 3 percent increase to a consumer’s bill --

MS. KELLY DERKSEN: Yeah --

MR. BOB PETERS: -- in rough numbers?

MS. KELLY DERKSEN: Yes, assuming next year on August the 1st of 2005, all of the riders that would come off the bill there would be a 3.2 percent increase, roughly speaking, to a typical residential customer on August the 1st of next year.

MR. BOB PETERS: And while you’ve called it an increase, Ms. Derksen, just so the record is clear, it would simply be reverting to the base rates that you’re asking this Board to approve today; is that correct?

MS. KELLY DERKSEN: Yes, but, we’re talking from the perception of the customer, what the customer would see.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, I’d like to take you to a book of documents that I circulated last week in your absence, but, I hope your colleagues were considerate enough to provide you with a copy.

And if they haven’t maybe Ms. Murphy, can bring to your attention Tab 14 in the Book of Documents. And Tab 14 in the Book of Documents that was prepared for my questions of the Centra panel has in it, Schedule 7.1.0, updated on August the 9th, of 2004. That's a document that you're familiar with, Ms. Derksen?

MS. KELLY DERKSEN: Yes, sir, I am.

MR. BOB PETERS: And if I go down to line 14 on Schedule 7.1.0, I note that in the far right-hand column, the costs for non-primary gas matters are $83.357 million, correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And if I follow along the line 14, Ms. Derksen, through the various columns, is it your evidence to the Board that based on your cost allocation, you have allocated that $83.4 million to the customer classes as shown on line 14?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: In the same Tab 14, Ms. Derksen, there's a second page which was taken from Tab 1 of your August 9th update, page 10 of 21, and the Centra column called pre-update, the pre-hearing update, really is the class by class, listing of the dollars that you have determined through cost allocation as to what each class is responsible for in this case -- in this Application before the Board?

MS. KELLY DERKSEN: Yes, that's true.

MR. BOB PETERS: And when the Board looks at these classes, Ms. Derksen, they're going to be familiar with -- with many of the ones that you've listed on Tab 1 page 10 of 21, but, when we come down to supplemental firm and supplemental interruptible, can you explain what those are to the Board?

MS. KELLY DERKSEN: As part of the implementation of unbundled rates that occurred in 1999, we essentially created three (3) new customer classes. And they're really -- they're really not customer classes per se, but for purposes of dealing with the Cost Allocation Study, we have included them as customer classes. Those three (3) classes would be the primary gas class, which is not part of this Application, in terms of costs.

And then the other two (2) are supplemental firm and supplemental interruptible. The supplemental firm and the supplemental interruptible that you see on this page are the supplemental gas costs that appear on the bill for each customer who takes that particular service.

(BRIEF PAUSE)

MR. BOB PETERS: Can you explain, Ms. Derksen, how those costs get allocated to the specific customer classes?

MS. KELLY DERKSEN: Mr. Peters, there are only two (2) classes, so if you're a firm customer you would pay the supplemental firm rate. And most of our -- other than the interruptible class, you're a firm customer.

The interruptible class would pay the supplemental interruptible rate and the split between the firm customers and the interruptible customers are based on the daily load curves that Mr. Sanderson prepares. And he is able to tell me, on a daily basis, how we anticipate to meet our firm requirements, in terms of supplemental gas, and how we're able to meet our interruptibles requirements, in terms of supplemental gas.

And based on those daily load curves then, I -- I simply assigned those costs that he provides me to the -- the firm customer class and the interruptible customer class. And the unitized rate that's developed out of that, is simply taking the total dollar amount that -- that is in that account and dividing by the total volumes that you expect to supply to a firm or an interruptible customer class for the forecast year.

MR. BOB PETERS: Can the Board take from your last answer, Ms. Derksen, that every firm customer on your system pays the same unit rate for the supplemental gas?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And likewise, every interruptible customer pays the same unit rate for their interruptible supplemental supply.

MS. KELLY DERKSEN: Yes.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, once you have decided as you did on Schedule 7.1.0, as to the cost to be allocated to the customer class, you now have to determine through a rate design mechanism how you're going to recover that amount of money; have I got that correct?

MS. KELLY DERKSEN: Yes, sir, you do.

MR. BOB PETERS: And so the net result of your cost allocation is to provide a revenue amount that you now want to recover from each of the customer classes?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: Ms. Derksen, is it correct that back in approximately 1997, the revenue to cost ratio was set at one point zero (1.0) for the various classes?

MS. KELLY DERKSEN: Yes, sir. As part of our cost allocation rate design review that occurred in -- before this Board, certainly in October of 1996, it was approved that all customer classes would be moved to unity, which means that whatever the -- the revenues are for the costs that we allocate to that class, would be exactly what we recover.

MR. BOB PETERS: You're referring to unity as being a ratio of one point zero (1.0)?
MS. KELLY DERKSEN: Yes, sir.
MR. BOB PETERS: And when you hit a ratio of one point zero (1.0), you're telling the Board that the -- that the revenue you recover through your rates, equals the costs that the Board has approved, and therefore, your books balance?
MS. KELLY DERKSEN: Yes.
MR. BOB PETERS: There's no deliberate effort made by the Utility for cross-subsidization between classes is there?
MS. KELLY DERKSEN: There is not, no.
MR. BOB PETERS: In terms of rate design changes -- I noted two (2) rate design changes, Ms. Derksen, and you can perhaps correct me if I'm incorrect, but one (1) of them dealt with the high volume firm demand rate determination; that was one (1) of them was it not?
MS. KELLY DERKSEN: Yes, sir.
MR. BOB PETERS: And the other was how you deal with the supplementary gas PGVA rate rider?
MS. KELLY DERKSEN: Yes.
MR. BOB PETERS: I'm not sure, do you see that as a rate design issue as well?
MS. KELLY DERKSEN: I think you could call it

that, yes.

MR. BOB PETERS: All right. In looking at the customer classes that you have, and I'll come to those two (2) rate design changes, Ms. Derksen, but in looking at your customer classes and designing the rates, the material demonstrates that you have what you call two (2) part rates for your SGS and your LGS class; is that correct?

MS. KELLY DERKSEN: Yes, that is.

MR. BOB PETERS: And when we say two (2) part rates, the first part is a basic monthly charge, and the second is a volumetric charge; is that correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: You told Ms. Murphy, in your answers to her this morning, that the Corporation can determine the costs by class to meet the demand or the capacity requirements, and you measure that for the SGS class and the LGS class, do you not?

MS. KELLY DERKSEN: We allocate demand costs to the SGS and LGS classes, however we do not have an explicit demand rate as part of their rate structure.

MR. BOB PETERS: Can -- and can you explain to the Board why you don't have a specific demand rate for -- for those two (2) classes?

MS. KELLY DERKSEN: There's actually a couple of reasons why, at this point, that we do not have a demand rate for the SGS and LGS class.

First, I think, and foremost, is the understandability that come -- or lack thereof, that comes with implementing a demand rate. It's a fairly complex issue to understand, particularly for residential customers.

So, it would be -- it's -- we've had a very difficult time with the basic monthly charge and understanding the concept of it. Demand charge would be that complicated and more, and so from that perspective, from a customer understandability and acceptability perspective, we do not employ a demand rate for that -- for those classes.

In addition, in order to implement demand rates for those customer classes, we would also need to have some kind of demand meter on their property or some kind of metering device that would allow us to read customers' consumption on a daily basis, and the cost to implement or install that kind of equipment on two hundred and fifty thousand (250,000), let's say, customers, would be fairly -- a fairly onerous cost.

MR. BOB PETERS: Recognizing those two (2) reasons -- in terms of the measurability reason, Ms. Derksen, is it Centra's assumption that the SGS customers have similar load characteristics and therefore they're treated the same?

MS. KELLY DERKSEN: I think generally speaking, they do have similar load characteristics, yes.

MR. BOB PETERS: But Centra does acknowledge that, within the SGS class, there can be and there will be different load usages by different customers that you have?

MS. KELLY DERKSEN: Sure, that's true.

MR. BOB PETERS: And the way you've told the Board that you recover your demand charges for the LGS and the SGS customers, is that you embed that in the volumetric charge. Would that be correct?

MS. KELLY DERKSEN: That's correct.

MR. BOB PETERS: And that assumes that those customers who use more volume will pay more of the what otherwise would be known as the demand costs?

MS. KELLY DERKSEN: That's true.

MR. BOB PETERS: All right. Turning on your -- and I'm just looking at Schedule 7.1.0 as an example, you have a list of your rates. That's at Tab 14, and also in Schedule 8 in the materials; Schedule 8.2.0 which I didn't put in the Book of Documents.

But in the customer class known as the special contract customer class, there is only one (1) customer in that class, correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And would it be correct to tell the Board that this is a rather unique rate structure for this particular customer class?

MS. KELLY DERKSEN: Yes, that’s true.

MR. BOB PETERS: And whereas the SGS customer or the SGC customer pays a ten dollar ($10) a month, monthly charge, the special contract customer pays about ninety-three thousand dollars ($93,000) a month as a basic monthly charge; is that correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: Can you explain to the Board why it’s structured in that fashion?

MS. KELLY DERKSEN: A number of years ago, probably in the early 1990’s, the special contract customer was given the option of the type of rate design that it preferred and in discussions and negotiations of their special contract, it was agreed upon that not only would we recover all of the customer related costs that you typically recover in a basic monthly charge.

Those costs generally are on-site costs, are costs that are specific to a customer, like a meter and a service line and a reg -- and a regulator.

So, in addition to recovering the customer related costs in the basic monthly charge, it was decided that they would also -- we would also embed in the basic monthly charge the fixed capacity related costs or costs associated with providing transmission type service to those -- to that particular customer. So, both of those types of costs are included in the basic monthly charge.

And even at that, the full amount of customer related costs are not recovered from a residential customer. On average, it’s about -- represents about twenty-three dollars ($23) a month that it would work out to be for a basic monthly charge for a residential customer.

The difference between what we bill today at ten dollars ($10) and the twenty-three dollars ($23) that in actuality it is, that -- that thirteen dollar ($13) difference is also embedded in their volumetric charge.

MR. BOB PETERS: From that answer, Ms. Derksen, do I take it that there was a negotiation with a special contract customer as to a rate structure and that rate structure has remained in effect since then?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And have been no requests to change the rate structure?

MS. KELLY DERKSEN: No.

MR. BOB PETERS: And I note on your rate schedules, there is a small volumetric charge to the special contract customer; can you explain what that -- what that’s for?

MS. KELLY DERKSEN: The small volumetric charge that appears on the special contracts bill, is the variable downstream cost that they would be responsible for.

In this particular case, it’s primarily unaccounted for gas, for that particular class.

MR. BOB PETERS: The Board will hear more about that tomorrow, according to the schedule, correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: All right. A relatively new customer class in your classes, Ms. Derksen, is the power station class, correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And this is for the power stations of your parent company in Selkirk, Manitoba and one in Brandon, Manitoba?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: This was also a matter that was raised by way of a contract and -- and brought to the Board by way of a contract last year?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: Can you explain why the basic monthly charge for this customer class is approximately twelve thousand dollars ($12,000) a month?

MS. KELLY DERKSEN: This -- this customer, as well, was given through the negotiations that we went through, in terms of determining a contract for these two (2) customers, it was decided that they preferred a more -- a three (3) part rate that we would see, typically in our larger volume customers.

So, that the only cost that we recover through their basic multi-charge, are -- is what is reflective or what is known as the customer or on-site costs of -- of the two (2) properties, one (1) in Brandon and the other in Selkirk.

MR. BOB PETERS: The power station class then has a three (3) part rate because they pay a demand charge, as well as a volumetric charge, on top of the basic monthly charge?

MS. KELLY DERKSEN: Yes.

(BRIEF PAUSE)

MR. BOB PETERS: Can you explain to the Board, why this is a more advantageous rate structure than -- than perhaps one (1) that was used -- by the special contract customer?

(BRIEF PAUSE)

MS. KELLY DERKSEN: Trying to recall some of this information from last year and I believe, it has to do with the variable -- the variable nature of the use of the two (2) plants. It's anticipated that the use of those system -- those two (2) systems will be -- will fluctuate to -- to a significant degree and hence they have both a very poor load factor.

And those are a couple of the reasons why they preferred a three (3) part rate because particularly for the demand component of the bill, the demand gets set in -- in any given winter. And once it's set, you pay that same amount for twelve (12) years -- sorry for twelve (12) months.

And once that's -- once that's set, they would be able to establish what they would pay for -- for the upcoming year, certainly in terms of demand costs.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, in terms of your power station class, that matter -- the provision of service to the customer at the two (2) power stations was done following a feasibility test; is that your understanding?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And is it also your understanding that the gas supplied by this -- to this customer class is not system supplied gas?

MS. KELLY DERKSEN: That's correct.

MR. BOB PETERS: And do you have an understanding as to why that is the case?

(BRIEF PAUSE)

THE CHAIRPERSON: Mr. Peters, we'll have a break at some point. You can pick it when you wish.

MS. KELLY DERKSEN: Perhaps I could back to you on -- on the implications of the fact that the -- both the power stations are supplied gas by -- by a third party.

MR. BOB PETERS: Mr. Chairman, this might be an appropriate time, and I'll move to a new area after the break.

THE CHAIRPERSON: Okay, we'll be back at 10:25.

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

THE CHAIRPERSON: Mr. Peters, you can resume.

MR. BOB PETERS: Thank you, yes.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Ms. Derksen, I recall your evidence of before the break, indicating that in terms of the basic monthly charge, the SGS class and the LGS class don't have a 100 percent of their customer related costs included in that; have I got that correct?

MS. KELLY DERKSEN: Yes, you do.
MR. BOB PETERS: And by contrast, the high volume firm, the mainline customer and the interruptible customer class; there you do embed a 100 percent of the customer related costs in the basic monthly charge?
MS. KELLY DERKSEN: Yes.
MR. BOB PETERS: If we turn, Ms. Derksen, and the Board, to Tab 15 of the Book of Documents that I've circulated, I want to check with you, Ms. Derksen, and understand the structure.
Tab 15 of the Book of Documents, Ms. Derksen, has a copy of PUB/Centra-100(a), attachment included as the first page. Have you that page, ma'am?
MS. KELLY DERKSEN: Yes.
MR. BOB PETERS: And looking at that page on line 5 for the SGS class, for a consumer who's using twenty-eight hundred (2,800) cubic metres a year, the basic monthly charge you show is a hundred and twenty dollars ($120) a year, correct?
MS. KELLY DERKSEN: Yes.
MR. BOB PETERS: Would it also -- and then you -- based on the volumetric charge to that same consumer, they'd pay approximately a thousand and thirty-one dollars ($1,031) for a total annual bill of about eleven hundred and fifty-one dollars ($1,151)?

MS. KELLY DERKSEN: Yes.
MR. BOB PETERS: And in this Interrogatory, you were asked to then revise that methodology and assume that you recovered all customer related costs in the basic monthly charge, and that’s what you’ve attempted to do under lines 14 to 21 under Part A of the answer, correct?
MS. KELLY DERKSEN: Yes, sir.
MR. BOB PETERS: And would it also be correct, Ms. Derksen, that the customer who is shown at twenty-eight hundred (2,800) cubic metres on line 5 would be the same customer as shown on line 17 of PUB/Centra-100(a)?
MS. KELLY DERKSEN: Yes.
MR. BOB PETERS: And that would also be the same customer who then will be shown on line 28 of this same attachment?
MS. KELLY DERKSEN: Yes, sir.
MR. BOB PETERS: And when -- when the -- when the Board looks to see the total bill, the total bill varies somewhat. Can you explain why that total bill would vary or is it -- is it supposed to be, in a perfect world, the same number? Can you explain that to the Board?
MS. KELLY DERKSEN: It does vary and there’s -- there’s reason that it does vary and it has to do with the recovering of the -- the fixed costs through the volumetric charge.

In the first situation, where we're recovering ten dollars ($10) per month or a hundred and twenty dollars ($120) per year, in the basic monthly charge, we also have a volumetric cost of -- just a little over a thousand dollars ($1,000).

What happens is because the total cost in providing customer related services to the -- to a residential customer is more than ten dollars ($10) a month, we recover the difference between the ten dollars ($10) that they pay and the twenty-three dollars ($23) that it actually costs.

That thirteen dollar ($13) difference is then recovered through a volumetric charge and the more consumption that a customer uses, the more that they're going to pay toward those fixed costs.

And as you start re-shaping that rate structure, as you'll see in Part A and -- or the -- the second set of rows and then the third section as well, you'll see that as we start including more of the fixed costs and recovering them in a fixed way, the volumetric charge is going to be reduced but that's really re-shaping who is paying for the fixed costs and who is contributing to the variable costs.

Those customers typically who consume less than average for a typical -- for a residential customer which, on average is thirty-two hundred (3,200) cubic metres of year -- a year, those customers who consume less than that amount will generally pay less than their fair share on an annual basis, as a result of the current rate structure.

MR. BOB PETERS: And so the typical residential consumer consuming three thousand two hundred (3,200) cubic metres, the total bill for that customer is, in essence, the same amount under -- under any of these scenarios?

MS. KELLY DERKSEN: Right. It’s virtually unchanged.

MR. BOB PETERS: All right. And so what we’ve shown -- what you’re showing the Board, then, in -- at the top of the page is that a hundred and twenty dollars ($120) a month is your ten dollar ($10) a month basic monthly charge, with the balance recovered through the volumetric charge, correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And you -- on line 17 or -- and eighteen (18), for example, the basic monthly charge of two hundred and seventy-six dollars ($276) is the twenty-three dollar ($23) a month number that you’ve put on the record, both before and after the break?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And what you’re telling the

Board there is if the basic monthly charge was increased, the volumetric unit cost would be adjusted downward and the total volumetric cost would be lower, but for the typical residential consumer, it would amount to the same amount on an annual basis?

MS. KELLY DERKSEN: The total bill would be unchanged, yes.

(BRIEF PAUSE)

MR. BOB PETERS: And if we look at the highest consumption that you show on lines 7, on lines 19 and on lines 30 for the residential customer, that's using the highest consumption of eleven thousand three hundred (11,300) cubic metres -- I suppose that's heating the pool as well -- that customer would expect their annual bill to decrease because those costs, the fixed costs and the -- sorry, the customer related costs and the capacity related costs in your examples are recovered through the basic monthly charge?

MS. KELLY DERKSEN: Yes, sir, that's true.

MR. BOB PETERS: Okay. And then in terms of the difference between the customer on line 17 and the customer on line 28, what you've attempted to do there is include on line 28, not only the customer related costs, but, the demand related costs that you can identify, is that correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: Would you agree with me, Ms. Derksen, that because you're only charging a hundred and twenty dollars ($120) a year or ten dollars ($10) a month for a basic monthly charge, there are customers in the class that are subsidizing other customers within the class, with respect to those customer and demand related costs?

MS. KELLY DERKSEN: Yes, that's exactly what this particular schedule shows.

MR. BOB PETERS: And what it does show, is that the large volume customers are typically subsidizing the low volume customers within this class?

MS. KELLY DERKSEN: Yes, that's true.

(BRIEF PAUSE)

MR. BOB PETERS: In terms of the amount of money that you recover from the SGS class, Ms. Derksen, does it change under any of your scenarios?

MS. KELLY DERKSEN: Can you clarify what you're asking, please?

MR. BOB PETERS: You've agreed with me, Ms. Derksen, that within the class, the high volume consumers currently cross subsidize to some extent, some low volume consumers, correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: Would you -- is there any cross subsidization between the SGS class and the LGS class, in your example?

(BRIEF PAUSE)

MS. KELLY DERKSEN: For the class, Mr. Peters, we're looking at just restructuring who pays it. So, the class, in essence, should be recovering the same amount of revenue requirement regardless of who that you're collecting those revenues from. So, the answer to your question, is no.

MR. BOB PETERS: So, there's no cross subsidization between classes in your rate structure, but, there may be cross subsidization within a particular customer class?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: Ms. Derksen...?

(BRIEF PAUSE)

MR. BOB PETERS: Before I leave Tab 15 and PUB/CENTRA 100(a), Ms. Derksen, I look at the LGS customers and you've given two (2) examples in your --in your answer.

The LGS customer is shown here, there’s a greater amount of cross subsidization that appears relative to these two (2) customers in the class. Would that -- would you agree with me?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And so when the Board looks at line 9, for example, and sees the LGS customer having an annual bill of two hundred and nineteen thousand dollars ($219,000), and then at the line 32, the same consumption level for this customer, the bill would go down to one hundred and eighty-two thousand dollars ($182,000) if all customer and capacity related costs were embedded into a basic monthly charge?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: Has the Utility thought about whether or not, because of that cross subsidization issue, the LGS customer class should go from a two (2) part rate to a three (3) part rate?

MS. KELLY DERKSEN: We have certainly discussed it internally. We’re not prepared, of course, at this point to make any proposal but we would -- I would expect that as part of the next general rate application that we may be wanting to make a proposal with respect to three (3) part rates for the LGS class.

MR. BOB PETERS: Can you tell the Board, at the next general rate application, which Mr. Warden said is, I believe, forecast for possibly this fall depending on the -- on the Hydro Board's decision, would you be looking at changing the basic monthly charge within the LGS and the SGS class?

MS. KELLY DERKSEN: Certainly not for the SGS class. As I discussed before, there's a fair amount of customer acceptability and understandability issues that revolve around the issue of the basic monthly charge for residential customers.

So, I'm not sure that we would be prepared to move off the ten dollars ($10) that we currently charge those types of customers.

For the LGS class, it would be something that we would want to look at. I would -- I would hazard a guess though, that we would probably look toward more of upping the basic monthly charge to be reflective of the -- the cost related -- the customer related costs that we incur, rather than incorporating both the demand and the customer related costs, in the basic monthly charge, because I don't believe that there is a correlation to the way that demand costs are incurred and recovering them by the number of customers.

MR. BOB PETERS: Sticking with the SGS class, and that includes the -- the residential consumers, correct?

MS. KELLY DERKSEN: Mr. Peters, it actually includes both the residential and some small commercial.

MR. BOB PETERS: In the SGS class, you indicate that the company has. Do you know for how many years you've had the ten dollar ($10) basic monthly charge for that class?

MS. KELLY DERKSEN: Probably since the late 1980s, I'm guessing.

MR. BOB PETERS: And you indicated that the Corporation is reluctant to change that, because the Corporation understands that there may be understandability issues with customers in that class?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: What you're telling the Board is that customers don't understand why they pay ten dollars ($10) a month, even if no molecules of gas flow down the line?

MS. KELLY DERKSEN: Yeah, I think it's particularly a concern in the summertime when customers aren't consuming necessarily any consumption, and yet they're still receiving a fixed monthly bill from -- from the Corporation. The customer probably does not understand, you know, that there are fixed ongoing costs that the company incurs in providing that service, and that they need to pay for. They don't see those links, so, yes, I would agree with your statement.

MR. BOB PETERS: And the concern then that I'm reading into your answer, and you can correct me if I'm wrong, Ms. Derksen, is that you would have a lot of upset customers if you tinkered with that, in my words, tinkered with that basic monthly charge?

MS. KELLY DERKSEN: I would hazard a guess, yes.

MR. BOB PETERS: And why is it when you adjust or consider adjusting the basic monthly charge to other customer classes, you don't feel you have the same concerns, or the same customer issues?

MS. KELLY DERKSEN: I think some of the larger volume customers have perhaps a better awareness of the types of costs, certainly for businesses -- businesses can understand the types of costs that they would incur, and so that they could liken that or at least acknowledge that Centra, as a utility, would incur similar types of -- of costs in providing service to its customer.

So, I think there's just a better awareness of the types of costs that companies incur in providing service to customers.

MR. BOB PETERS: The long and the short of it is, Ms. Derksen, Centra recovers a 100 percent of its costs from the SGS class, under its existing rate design, and you see no reason at this point in time to alter that?

MS. KELLY DERKSEN: The long and the short of it is that this is not a revenue requirement issue, it's a rate design issue. And, yes, for the SGS class, I think that we probably will leave that unchanged for the foreseeable future.

MR. BOB PETERS: All right. I want to turn with you, Ms. Derksen, to demand related costs. And this might be just a precursor to some questions that I'll have later for you today on the high volume firm issue, specifically.

But back at Tab 14 of the Book of Documents, which is -- includes a copy of Schedule 7.1.0, dated August the 9th of 2004, I go down to line 24 -- sorry, Ms. Derksen, I'll give you a minute to catch up to me.

Have you Schedule 7.1.0, either in your Application or in Tab 14 of the Book of Documents that I've circulated, Ms. Derksen?

MS. KELLY DERKSEN: I do.

MR. BOB PETERS: Looking at line 24 on that Schedule 7.1.0, I note under the SGS and LGS columns, there is no percent of demand recovered in a demand cost, is that what that's showing?

MS. KELLY DERKSEN: Yes, that's true.

MR. BOB PETERS: And you've told the Board that those kind of costs are included mostly in the volumetric charge for those customer classes?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: When we go to the co-op class, the mainline class, the special contract class and the power station class, 100 percent of the demand costs are recovered in the demand component of the three (3) part rates. Is that also correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And when I look to the high volume firm, and the interruptible customer classes, only 65 percent of demand costs are recovered in the demand component of rates; is that also correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: Can you tell the Board where is the other 35 percent of the demand costs recovered?

MS. KELLY DERKSEN: Similar to the rate structure for the SGS and LGS class where we don't recover all of the fixed customer costs in the basic monthly charge, the remaining amount is recovered through the volumetric charge.

The same as for these two (2) particular customer classes, the high volume firm and interruptible customers have demand rates, but we recover only 65 percent of the fixed capacity costs in that demand rate. The remaining 35 percent is recovered through their variable transportation and distribution charge.

MR. BOB PETERS: Would it be correct again, Ms. Derksen, that there would be no cross-subsidization between the classes on account of demand charge, but there may be cross-subsidization within the class?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: Ms. Derksen, Tab 15 of the Book of Documents that was circulated has a copy of PUB/Centra-100(b) attachment dated June 18th, 2004; have you that, at hand?

MS. KELLY DERKSEN: Yes, I do.

MR. BOB PETERS: And just for the benefit of the Board and to refresh our memories, Ms. Derksen, the demand component in rates for the three (3) part customer classes is not uniform as you've told us and, in fact, for the high volume firm customer and the interruptible customer, it was at one point only 50 percent of demand costs being recovered in demand rates; is that also right?

MS. KELLY DERKSEN: That's true, Mr. Peters.

MR. BOB PETERS: And when did the Board approve an increase from 50 percent demand related costs being recovered to 65 percent recovery in the demand rate?

MS. KELLY DERKSEN: It was approved through Centra -- Centra's 2003/'04 General Rate Application and the Board Order was 118/03.

MR. BOB PETERS: And this has a history to it, as well, Ms. Derksen, in that you can may be explain to the Board why only 50 percent of demand related costs were even in the demand component of rates back in 2003.

MS. KELLY DERKSEN: This issue does have history tagged along with it. It results or it stems from our 1996 cost allocation and rate design study and review and we had, at that time, implemented three (3) part rates for our larger volume customers or were proposing to do so.

At that time, the larger volume customers had a -- a two (2) part rate and we were -- we were wanting to move to having a basic monthly charge, a volumetric charge and a demand charge.

Because of the impacts that moving to the three (3) part rates were --- was going to have on some of the customers, particularly in the high volume firm and the interruptible customer classes, we introduced a concept that I will refer to as gradualism and that is we wanted to only implement part of the charge in demand costs in the demand rate to the high volume firm customer and also the interruptible customer because of the significant impacts that there were going -- that there was going to be on several of the customers within those classes.

MR. BOB PETERS: And that gradualism resulted in your starting at 50 percent?

MS. KELLY DERKSEN: Yes, Mr. Peters.
MR. BOB PETERS: And between fifty (50) and the move to 65 percent last year, has there been any other incremental move?
MS. KELLY DERKSEN: Not in the proportion of demand costs that we recover in the demand rate, no.
MR. BOB PETERS: Let’s just have a look, then, at PUB/Centra-100(b), Ms. Derksen, and I have that in Tab 15 of the Book of Documents that hopefully you have in front of you.
Looking at the -- Line 1, under existing rate structure, you’re showing a 65 percent recovery of demand costs through the demand rate, correct?
MS. KELLY DERKSEN: Yes, sir.
MR. BOB PETERS: And at line 20, the recovery of 50 percent of demand related costs, that’s the way it used to be as late as the General Rate Application last year in 2003?
MS. KELLY DERKSEN: Yes.
MR. BOB PETERS: And at line 40, you’re showing what would be the impact if 100 percent of the demand related costs were recovered in the demand component of the three (3) part rates?
MS. KELLY DERKSEN: Yes, sir.
MR. BOB PETERS: And the 100 percent recovery

of the demand related costs is the current situation for the mainline customers and the interruptible customers, correct? I'm sorry, for the -- the mainline customers?

MS. KELLY DERKSEN: Yes, for the mainline customers, the power station and the co-op class, yes.

MR. BOB PETERS: All right. In looking at the information you've presented here, and let's pick a customer -- maybe you can explain to the Board, what you mean by load factor, which is one (1) of your columns in your chart?

MS. KELLY DERKSEN: Load factor is essentially how efficiently that a customer uses Centra's system. It's basically calculated by taking a total annual consumption of a customer divided by three hundred and sixty-five (364) days which tells you what a customer uses on average, per day. And you would then divide by a customer's peak requirements, or that consumption in the year in which a customer uses the most amount of consumption.

So, that tells you how efficiently the customer uses gas on Centra's system.

MR. BOB PETERS: You recognize in that answer, Ms. Derksen, that it -- it doesn't necessarily mean the customer has an inefficient business or process, it's just that the difference between their peak and their average use results in them having some unutilized ability on the system?

MS. KELLY DERKSEN: Yes, I don't mean to be offensive to any -- any particular business, I'm just talking from a strictly a cost allocation and a Centra system point of view, only.

MR. BOB PETERS: Would it be correct to say, for a 40 percent load factor customer, Ms. Derksen, that on average, they're only utilizing 40 percent of the infrastructure that you have in place for that customer class, or -- or for that customer?

MS. KELLY DERKSEN: Yeah, I think you could look at it that way.

MR. BOB PETERS: But, you still have to have 100 percent of the infrastructure in place, for the peak day?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: All right. Can you tell the Board, whether there are any, in fact, customers that you have in the high volume firm class, who have load factors outside of the range that is shown on PUB/CENTRA 100(b)?

(BRIEF PAUSE)

MS. KELLY DERKSEN: I don't believe we have any customer class in the high volume firm class, particularly that would have a load factor in excess of 75 percent. I'm not sure about the interruptible class, however.

MR. BOB PETERS: Just to re-phrase that answer, Ms. Derksen, to the best of your knowledge as you're here, all of your high volume firm customers, have load factors somewhere between 40 percent and 75 percent?

MS. KELLY DERKSEN: Sorry, I should have been clearer with that. There are no customers in the high volume firm class whose load factor exceeds 75 percent, but, we have a number of customers in the high volume -- high volume firm class, whose load factor is less than the 40 percent.

MR. BOB PETERS: Do you know how low of a load factor you have for customers in that high volume firm class?

(BRIEF PAUSE)

MS. KELLY DERKSEN: Mr. Peters, based on the information I have that is based on data from August 1st, of 2003, until approximately July the 31st, of 2004, I have one (1) customer who has a load factor of 17 percent in that class.

MR. BOB PETERS: And not to get too specific here, Ms. Derksen, but, is that the only customer below 40 percent load factor?

MS. KELLY DERKSEN: No, we have a number of customers lower than 40 percent.

MR. BOB PETERS: All right. And that's the lowest one at 17 percent?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: All right, thank you. When we look at the specifics of this PUB/Centra-100(b), Ms. Derksen, as I understand it, for a customer on line 4, the high volume firm customer at a 40 percent load factor, with a consumption of eight hundred and fifty (850) ten (10) cubed, M cubed, they would have an annual bill of approximately two hundred and ninety-one thousand dollars ($291,000)?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And included in that bill would be a demand cost of forty-seven thousand dollars ($47,000)?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And what you're showing the Board is that the former situation for that customer, down on line 24, when only 50 percent of the demand costs were recovered, that the total bill was two hundred and eighty-nine thousand dollars ($289,000) and of that approximately thirty-nine thousand (39,000) was the demand costs?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: All right, and just to complete that, if -- does the Utility have any plans to move from a 65 percent recovery of demand costs through the demand rate to a 100 percent recovery of demand costs through the demand rate?

MS. KELLY DERKSEN: Something again that of course we've talked about internally, but we haven't concluded on. We have a bit of a concern with the customers in the interruptible class, not so much with the customers in the high volume firm class, as I sit here today.

But with the interruptible customers, we have a number of customers who are very seasonal; they only consume gas between the months of April and generally October. It could be an asphalt plant or a similar customer to that. And because they only consume gas during those periods, if we move to recovering a 100 percent of the demand costs in the demand rate, because the demand ratchet is not set in the summer months, they would not incur any demand related or capacity related costs on Centra's system.

So, we have to really look at that issue versus which is really a non-cost causal issue, versus you know, a cost responsibility in that class.

MR. BOB PETERS: Do you have a similar concern for the high volume firm customers that you have, in terms of the seasonality of their business?

MS. KELLY DERKSEN: We don't see nearly that type of customer in that class, so that's not an issue that would be affected by the customers in the high volume firm class, no.

MR. BOB PETERS: But that -- but you'd acknowledge, and I don't want to get too far ahead of ourselves here today, but customers in the high volume firm class could set their peak, their annual peak, in the summer months, as opposed to the winter months?

MS. KELLY DERKSEN: You could set -- you could set a peak, but you would not be billed on that peak, no matter what customer class that you're in. You would be billed demand costs only, based on the peak that you establish between the months of November and March of any given year.

MR. BOB PETERS: And can you explain to the Board why you pick the winter months to determine the -- the peak for billing -- determine it?

MS. KELLY DERKSEN: Most gas utilities operate -- it's basically because of the winter coincident peak nature of our business, that we establish demand ratchets during the winter months only.

MR. BOB PETERS: But what you're saying then, Ms. Derksen, is that it's in those winter months that you have to put all the infrastructure in place so that you can meet the peak day in the winter, which is generally higher -- a higher peak than what you would occur -- that would occur in the summer months?

MS. KELLY DERKSEN: Generally speaking that's true, yes.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, in looking at PUB/Centra-100(b), is it again correct that the -- the amount of demand costs not being recovered through the demand charge end up in the volumetric cost?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And therefore, you would agree that within the high volume firm customer class, there would be cross-subsidization between customers, based on the fact that the demand cost is not 100 percent recoverable for each customer?

MS. KELLY DERKSEN: Yes, Mr. Peters. We encounter this exact same issue with respect to demand costs and the demand rate for the high volume firm and interruptible customers as -- it’s the same issue as the one that we talked about with respect to the basic monthly charge being recovered, partly through the basic monthly charge and partly through the -- the volumetric charge for the SGS and LGS customers. It’s the same issue.

MR. BOB PETERS: And would it be correct that the higher the load factor customer you are in the high volume firm class, the more you are cross-subsidizing the lower load factor when a 100 percent of the demand costs are not recovered in the demand rates?

MS. KELLY DERKSEN: I think that's a fair statement, Mr. Peters.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, just take me back to first principles on your cost allocation of -- of demand related costs. Can you -- can you tell me some examples what kind of costs would be demand related costs?

MS. KELLY DERKSEN: We have a couple of demand -- types of demand related costs. We have demand costs that we incur upstream of Centra's system, or basically costs that we incur in providing in transporting natural gas from the Alberta border to man -- to the Manitoba border.

So those would be costs that we incur essentially -- sorry, fixed capacity related costs that we incur from Trans Canada Pipelines. So, that would be one (1) type of demand cost that we incur.

The second -- and not all customers take that particular service, so not -- not everyone would have to pay that particular rate.

The downstream demand type costs that we incur would include things like the cost of our transmission pipe and the revenue requirement associated with it -- the cost of our distribution mains. And those are the types of demand or capacity related costs that we incur on Centra's system.

MR. BOB PETERS: Are those costs that you've just talked about of the nature that you can directly assign them to certain customer classes?

MS. KELLY DERKSEN: No, Mr. Peters. Those are very much shared costs. We have -- you know, two hundred and fifty thousand (250,000) customers on Centra's system. Each of those customers take access or use Centra's transmission system, for example. So, it's definitely not a cost that we can directly assign. It's a shared cost that needs to be allocated on -- on some reasonable basis.

MR. BOB PETERS: So a 100 percent of those costs are then allocated as opposed to assigned?

(BRIEF PAUSE)

MS. KELLY DERKSEN: I think the response generally is yes, recognizing that we have some customers on our system who only use our transmission system as opposed to our transmission and distribution system.

And so to that extent we have several customers who would not be assigned or allocated any of our distribution main costs.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, when we talk about cost allocation of these demand related costs, would you agree with me that in that area of -- of your work, it is the allocation of such costs that perhaps leads to the greatest controversy?

MS. KELLY DERKSEN: I would agree, Mr. Peters, yes.

MR. BOB PETERS: And whereas other costs that you incur are more readily shareable on a -- on a basis, this is one (1) in which you have to use certain principles and make certain judgments?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: Ms. Derksen, when you showed us on PUB/Centra-100(b) found in Attachment 15 that there were -- there's a customer -- at least one (1) customer that may have a load factor as low as 17 percent, are you able to re-do PUB/CENTRA 100(b) and include information for a 17 percent load factor customer; have you that readily available?

MS. KELLY DERKSEN: I've not calculated that myself, but, it's not something that's difficult to calculate. So, it could be done.

MR. BOB PETERS: Could I then ask for that as an undertaking from you, through your counsel to provide that to the Board, when it's completed?

MS. KELLY DERKSEN: Yes, sir.

--- UNDERTAKING NO. 9: Re-de PUB/CENTRA 100(b) with a 17 percent load factor.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: All right. Thank you. When we talk about the interruptible customer class on these same schedules, Ms. Derksen, does the load factor range, you said you weren't sure if it's -- if it's all within forty (40) to 75 percent; there maybe customers outside of it?

MS. KELLY DERKSEN: Mr. Peters, I don't know offhand, I'd have to check on that.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, if you find when you're checking that there are interruptible customers who have a load factor significantly less than 40 percent, or significantly above 75 percent, could you also re-calculate PUB/CENTRA 100(b) attachment to reflect those examples?

MS. KELLY DERKSEN: I could do that, yes.

MR. BOB PETERS: All right, we'll take that as an undertaking, as well. Thank you.

--- UNDERTAKING NO. 10: Re-calculate PUB/CENTRA 100(b) for interruptible customers.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Ms. Derksen, you were telling me a few minutes ago that the -- the areas of controversy and cost allocation often arise related to the allocation of the capacity or demand related costs, correct?

MS. KELLY DERKSEN: Yes, I think so, that’s true.

MR. BOB PETERS: And in terms of your cost allocation and rate design methodology, when is the last time that the overall methodology was reviewed by this Board?

MS. KELLY DERKSEN: As part of the cost allocation and rate design study that occurred in 1996.

MR. BOB PETERS: And when that was reviewed in 1996, did Centra bring in an expert or a consultant to assist with the development of the cost allocation methodology?

MS. KELLY DERKSEN: Yes, sir, we did.

MR. BOB PETERS: Do you recall who that was?

MS. KELLY DERKSEN: It was Resource Management Inc., RMI.

MR. BOB PETERS: Since 1996, would you agree with me that any changes to your cost allocation methodology have been relatively minor in nature?

(BRIEF PAUSE)

MS. KELLY DERKSEN: Mr. Peters, I think outside of the unbundling of rates that would be true and the unbundling rates was a significant endeavour by the Corporation.

MR. BOB PETERS: Have you had any consultant review your cost allocation methodology since 1996, Ms. Derksen?

(BRIEF PAUSE)

MS. KELLY DERKSEN: Mr. Peters, Centra Gas hired Navigant Consulting, as part of its 2003/’04 general rate application and through that particular review, Navigant, of course, had a look at the study and helped the Corporation deal with the changes that were occurring as a result of the costing structures between Manitoba Hydro and Centra Gas. So, that was the last time it has been reviewed.

MR. BOB PETERS: Refresh my memory, Ms. Derksen, was that a review that was filed with the Public Utilities Board as part of that hearing?

MS. KELLY DERKSEN: To the extent that we file the actual cost allocation model and all of the output information, yes, it was filed.

MR. BOB PETERS: And was the principle of Navigant, was that the same principle of the RMI organization that you utilized in 1996?

MR. DERRY MILLAR: Yes, sir.

MR. BOB PETERS: And perhaps you can remind me of his name?

MS. KELLY DERKSEN: John Little.

(BRIEF PAUSE)

MR. BOB PETERS: Other than filing the cost allocation methodology and the results at the 2004/'04 GRA, Ms. Derksen, was there a specific report prepared by Mr. Little of Navigant or when he was with a different company, relative to your Cost Allocation Study, post 1996?

MS. KELLY DERKSEN: No, sir.

MR. BOB PETERS: Is that something that the Corporation doesn't consider it needs review on, on a regular basis, Ms. Derksen? Is that something that -- at this point in time there's no plan to review it?

(BRIEF PAUSE)

MS. KELLY DERKSEN: There's nothing in that Cost Allocation Study that causes us significant concern that would lead for us to have a formal review of the cost allocation and rate design methodologies and principles, no.

MR. BOB PETERS: Are you able to estimate for the Board, Ms. Derksen, an approximate cost to have a consultant go through your cost allocation process, and provide a -- a report?

(BRIEF PAUSE)

MS. KELLY DERKSEN: Mr. Peters, it really depends upon the scope of -- of the review, so it will be highly variable, dependent on that.

MR. BOB PETERS: That's a polite way of telling me you -- you can't put a ballpark around that; is that what you're saying?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: Okay. Just so I don't lose focus on this, Ms. Derksen, you can help me, that the Cost Allocation Study, and you've shown the Board on Tab 14 of the Book of Documents, that's the end result of it in terms of how the costs are allocated by class, correct?

MS. KELLY DERKSEN: I'm going to answer, yes, that is the ultimate result of the Cost Allocation Study, just keeping in mind that the way that I allocate costs as part of a gas cost hearing is done using the same principles and methodologies of course, as what we would undergo through a full general rate application, but we have a much smaller model that we use to drive this information. It essentially does not include any of the non-gas cost portions of the rates.

MR. BOB PETERS: All right, I -- I accept that qualification, Ms. Derksen, but would we then talk about in terms of how do you recover by customer class, the amounts for the non-gas costs, that enters into the realm that you've told the Board is under a rate design?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: It's a separate area of -- of study and art, perhaps?

MS. KELLY DERKSEN: Perhaps, yes.

MR. BOB PETERS: All right. And in terms of rate design, is that essentially done internally by Centra and its parent company, or is there any outside consultants used on the rate design side of things?

MS. KELLY DERKSEN: Typically in our gas cost proceedings, we don't have a consultant review the rate design portion of our Cost Allocation Study.

Of course as part of the '03/'04 General Rate Application, in which Navigant did some work for us, they too have reviewed and looked at the rate design portion of our study.

MR. BOB PETERS: Was it the recommendation back in 1996 by RMI, that the Utility move to three (3) part rates, Ms. Derksen?

(BRIEF PAUSE)

MS. KELLY DERKSEN: Subject to check, Mr. Peters, I believe that's true.

MR. BOB PETERS: I'm just trying to find out, or get a recollection from the Board as to whether that was the -- the Utility's idea, or was it that was a recommendation from the consultant?

(BRIEF PAUSE)

MS. KELLY DERKSEN: Subject to check, Mr. Peters, I think it was RMI's proposal that Centra ultimately adopted.

(BRIEF PAUSE)

MR. BOB PETERS: I want to turn with you, Ms. Derksen, to the customer impacts, and you've given some evidence through Ms. Murphy on that already, but if you could turn in Tab 15 of the Book of Documents to the third page that I have in there -- the fourth page.

The third page I have is Tab 1 of August 9, 2004, page 14 of 21. Do you have that?

MS. KELLY DERKSEN: Yes, I do.

(BRIEF PAUSE)

MR. BOB PETERS: When I look at the -- Tab 1, page 14 of 21 that we have in the filing, Ms. Derksen, this one has not been updated for the -- for the September 2nd revisions made by the Corporation, has it?

MS. KELLY DERKSEN: It has not, no.

MR. BOB PETERS: And if I heard your testimony through Ms. Murphy, the only revision that's needed on this yellow Tab 1, page 14 of 21 is under the high volume firm customer and that is that the change was a decrease in annual bills, somewhere between 7.2 percent and 8.5 percent.

(BRIEF PAUSE)

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: All other customer class impacts would stay the same?

MS. KELLY DERKSEN: Yes, sir.

(BRIEF PAUSE)

MR. BOB PETERS: Specifically, Ms. Derksen, if we turn to Schedule 8.1.0, that's in Tab 15; it's the last page in Tab 15 of the Book of Documents. That's a -- that's a Schedule 8.1.0 from the August 9th update, correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And since then, you have filed on -- on green paper a revised -- further revised Schedule 8.1.0; is that also correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And again the -- the revision that has been made on September the 2nd affects only the high volume firm customer class and the proposed -- the proposed billed rates for the demand as well as the bill impacts. Would that be correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And, Ms. Derksen, when I look at Schedule 8.1.0 and it doesn't matter which colour at this point, when I look to the high volume firm customer class, what this schedule doesn't show is that there are some customers who have a lower load --load factor that are not depicted on this schedule.

MS. KELLY DERKSEN: That’s true, Mr. Peters.
MR. BOB PETERS: And subject to your checking, there may even be interruptible customers that do not fit within the load factor profile of 40 percent to 75 percent depicted on this schedule?
MS. KELLY DERKSEN: Yes, sir.
MR. BOB PETERS: When you file and -- file the answers to the undertakings that you’ve given me a few minutes ago, Ms. Derksen, would it be possible to get a further revised Schedule 8.1.0 to reflect the ends of the spectrum for the high volume firm as well as the interruptible customer class?
MS. KELLY DERKSEN: Yes, we could prepare that.
MR. BOB PETERS: Thank you.

--- UNDERTAKING NO. 11: Ms. Derksen to prepare and submit further revised Schedule 8.l.0.

CONTINUED BY MR. BOB PETERS:
MR. BOB PETERS: A point I just want to make sure is clear on the record, Ms. Derksen, is that what you are attempting to show the Board in Schedule 8.1.0 as well as on Tab 1, page 14 of 21, is you are trying to show the Board the comparison between twelve (12) months at the rates this

Board approve on August the 1st as well as -- compared to twelve (12) months under the rates that you propose go in effect on November the 1st of '04.

MS. KELLY DERKSEN: Yes. Schedule 8.1.0 is a prospective look, assuming the current rates are in place for the next twelve (12) months, versus the proposed rates that would be in place for the next twelve (12) months.

(BRIEF PAUSE)

MR. BOB PETERS: I wish you wouldn't have said that, but, in terms of the next twelve (12) months, we do know that in nine (9) months' time, there will be an adjustment made.

Do you -- do you agree with that, Ms. Derksen?

MS. KELLY DERKSEN: I thought about the same thing seeing as that came out of my mouth so, yes, recognizing of course that the rider component of the rates would only be in effect for nine (9) months. So, there's a couple of things happening here.

(BRIEF PAUSE)

MR. BOB PETERS: I don't want to repeat that discussion we've had, Ms. Derksen, but, that's just bringing to mind that in approximately nine (9) months time from when you propose these rates go in effect, the rate rider would be removed by the Utility and you would revert back to billed rates unless there was some reason not to by that time?

MS. KELLY DERKSEN: That --

MR. BOB PETERS: Sorry, I believe, I mis-spoke. You would revert to the base rates because the rate riders would be removed?

MS. KELLY DERKSEN: Yes, that's true and recognizing that these calculations on this page, are annualized calculations.

(BRIEF PAUSE)

MR. BOB PETERS: You've shown us now, the rate impacts that you're proposing as a result of your cost allocation and rate design, Ms. Derksen, but I want to go back on one area that we were talking about and that was the demand charges again.

You've I think told me that they are really 100 percent allocated through your cost allocation model, because they're not capable of being directly assigned to specific customers or customer classes; have I that correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And because of their shared nature of those costs, are those costs relatively constant year over year, or do they fluctuate considerably?

(BRIEF PAUSE)

MS. KELLY DERKSEN: I've had to think about this a little bit further, we -- like I had advised before, we incur different types of demand costs, we have upstream demand costs, or those costs that we will incur from Trans-Canada pipeline.

Generally, speaking they don't tend to fluctuate a significant amount from year to year. Generally speaking, I think it probably demands on your point of view, as well and I think there's a number of considerations, like US exchange, and so forth. And Mr. Sanderson may want to add something -- may want to comment on that.

In addition, on Centra's system we don't have a whole lot of change on our transmission related system. We have a fair degree, I guess you could say, of movement on our distribution system, as it relates to customers adding.

There's a significant amount of housing starts in our province and in our service territory. So, of course, that would cause you to have to upgrade your system and so forth. So, I guess generally speaking, you could say there's not a whole lot of movement.

MR. BRENT SANDERSON: If -- if I might just take this opportunity to give some perspective as to the variability of the upstream demand costs.

The upstream demand costs related to our storage assets in Michigan and -- would be subject to the $14.7 million annual revenue cap that Mr. Stevens discussed last week.

So, in US dollars, those upstream demand costs aren't subject to any variation, at all. They would, however, be subject to variation related with changes in the Canada/US exchange rate applied to those US dollar tolls.

Normally, we don't -- we haven't seen a lot of variation, but in a situation like the past two (2) years where we've seen a thirty cent (.30) plus move in the US Canadian exchange rate, to that extent you would see a similar fluctuation in those upstream demand related costs.

In terms of the TCPL costs, they would only be subject to variation related to the toll applications that TCPL would file and seek subsequent approval for from the NEB from year to year.

They've filed some applications over the past number of years, seeking from a historical perspective, relatively large increases, but to give you an idea of what that means in terms of variability in those upstream demand tolls relative to the market price for natural gas, for instance, they're an order of magnitude lower, as compared to what we'd see in terms of variability of the market price for the commodity itself.

MR. BOB PETERS: Thank you for that, Mr. Sanderson, and Ms. Derksen.

If I take from those answers that the -- the demand charges are relatively constant year over year, you then have to allocate those to the various customer classes, correct, Ms. Derksen?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And when you allocate those to the various customer classes, do you find on an annual basis, there is great variability or is it again relatively constant?

MS. KELLY DERKSEN: Mr. Peters, between 1998 and 2003/'04, we didn't have any change in our -- in our allocation of demand costs, because we never went through a general rate application, so between 1998 and our Application in 2003/'04, we did see a little bit more movement than I think we would see on a year over year basis, because it's such a length of time in between our applications, from year to year on -- with respect to our Gas Cost Applications, which are just upstream demand component would be subject to like other than what Mr. Brent -- Mr. Sanderson has indicated, there's not a whole lot of movement on the upstream demand component.

MR. BOB PETERS: Would a similar answer apply to the downstream costs, Ms. Derksen?

MS. KELLY DERKSEN: I would agree if we were talking year over year, yes.

MR. BOB PETERS: And in terms of how those costs then get allocated, specifically in the customer class, can you explain for the Board, for example, looking at your Schedule 7.1.0, you show on line 4, the upstream demand costs of about $26.5 million, and then on line 9 you have downstream demand costs of about I guess seventy-eight thousand dollars ($78,000)?

MS. KELLY DERKSEN: I -- I can clarify that for you, Mr. Peters. It looks a bit odd at first glance.

The -- the seventy-eight thousand dollars ($78,000) that you see on line -- I’m not sure what line it is, I don’t have numbers on my mine line -- on line 9, is only with respect to Monell (phonetic) Pipelines, because don’t forget that this particular Application only deals with the gas cost portion of our rates. It’s not a compilation of all of our costs that Centra incurs in providing demand related services to its customers.

The upstream component, the $26 million that we were speaking of, is allocated to customer classes on the basis of our peak and average methodology, which assigns a weighting to each customer class, based on that class' contribution to both peak day and contribution based on total volumes, compared to total volumes of total system.

(BRIEF PAUSE)

MR. BOB PETERS: From that answer, Ms. Derksen, would it be correct to say that based on the number of customers and the volumes and the other factors that you utilize, the dollar amounts allocated by classes relative to each other, will vary year over year?

MS. KELLY DERKSEN: They will vary year over year, yes.

MR. BOB PETERS: All right. And that variance was based on -- on what factors?

MS. KELLY DERKSEN: To the extent that customer numbers change, customer volumes change, peak day information changes; all of those factors contribute to the allocation of demand costs and that's what would cause it to fluctuate from year to year.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, has the Corporation ever reviewed how much the demand costs fluctuate year over year, attributable to new customers that are added on to the system?

(BRIEF PAUSE)

MS. KELLY DERKSEN: Mr. Peters, not since I've been here, no.

(BRIEF PAUSE)

MS. KELLY DERKSEN: Which I would say is, probably in the last five (5) years we have not done such a study.

MR. BOB PETERS: You assume, though, that to add new residential customers, the -- the demand costs for those residential customers that you add to the system will be comparable to the demand costs of those customers already on the system?

MS. KELLY DERKSEN: Can you repeat your question to me, please?

MR. BOB PETERS: Would it be a reasonable assumption that, when you add new residential customers to the system, that the demand related customers are equated to what the demand related costs are for those customers already on the system?

(BRIEF PAUSE)

MS. KELLY DERKSEN: If you look at it from a very pure point of view and that is you need to add pipe every -- in the ground as it relates to, say, distribution mains every time that you add a customer, I would not agree with your -- your premise because what we include in terms of demand costs or distribution main costs is a historical cost and when you bring in an updated current value of -- of demand related costs into your study, of course that's going to be vastly different than what your books are showing at historical value.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, how does the company deal with the -- with plant closures or expansions that occur, in terms of allocating demand costs?

(BRIEF PAUSE)

MS. KELLY DERKSEN: We don't look at those things in isolation. It's a -- a compilation of customers on our system and all costs that Centra incurs in providing that service. So, it’s -- it’s not viewed as a discrete allocation, it’s a compilation of all of your customers and all of your costs.

(BRIEF PAUSE)

MR. BOB PETERS: To provide these numbers that you have for the Board, you’ve -- you’ve forecast them forward for the ’04/’05 fiscal year. Would that be correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And in that situation, if you become aware of a plant closure in one of the customer classes, do you remove from that customer class the costs that were associated with that customer that’s closing, or do those costs remain?

MS. KELLY DERKSEN: There is some plant that would obviously be removed if a customer closed. The on-site plant, for example, would be likely removed; not in all circumstances, but in many circumstances.

The actual pipe in the ground, the -- the pipe that connects the customer from the distribution main to -- to the meter, that may or may not be removed, of course dependant on the -- the sit -- the circumstance.

The distribution pipe that serves that customer would not be removed. It would -- it would remain constant and remain on -- on Centra’s books.

MR. BOB PETERS: So, the remaining customers in the class would be expected to pay a portion of that cost?

MS. KELLY DERKSEN: Right. That’s true.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, I want to turn with you to the supplemental gas issue and looking back in the materials, the supplemental gas portion of the --of your filing was quantified and I -- I have it in my notes here as $19.7 million but I wonder if you can just verify that.

(BRIEF PAUSE)

MS. KELLY DERKSEN: That’s not the correct amount. I -- I could find the correct amount for you though.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, maybe we can do it this way. If I turn to tab 10 of the Book of Documents and your Schedule 6.2.4, updated to August the 9th. I took a number of $19.7 million ...

(BRIEF PAUSE)

MS. KELLY DERKSEN: Mr. Peters, perhaps you were correct. I come up with a number of perhaps 19.67 million or 19.7 million.

MR. BOB PETERS: All right --

MS. KELLY DERKSEN: And we're talking about the forecast of the '04/'05 year?

MR. BOB PETERS: That is correct in my question, so we'll -- we can -- we can use 19.7 as the approximate number, Ms. Derksen?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: All right. And the Board has heard that that represents the forecast costs for storage and the costs related to the US supply, correct?

MS. KELLY DERKSEN: Storage as it relates to supplemental gas. We also have storage -- primary gas that's put into storage, so that would not be included in that component.

MR. BOB PETERS: And you provide the supplemental gas for all of your sales customers, as well as the WTS customers?

MS. KELLY DERKSEN: Yes, we do.

MR. BOB PETERS: And I think we understood from the first panel that the quantity of supplemental gas

that’s needed will vary, largely dependant on the weather?
MS. KELLY DERKSEN: Yes, sir, that’s true.
MR. BOB PETERS: And I think you told me this morning, that the supplemental gas rates that you charge through to your customers, are the same for all firm customers; they all pay the same supplemental gas rate?
MS. KELLY DERKSEN: Yes, true.
MR. BOB PETERS: And they -- that supplemental gas rate for firm customers, is different from the supplemental gas rate paid by interruptible customers?
MS. KELLY DERKSEN: Yes, sir.
MR. BOB PETERS: Speaking of interruptible customers, Ms. Derksen, were there actual interruptions of those customers in 2003/’04?
MS. KELLY DERKSEN: Yes, sir, there were.
MR. BOB PETERS: And what were the you -- the primary reasons for interruption?

(BRIEF PAUSE)

MR. BRENT SANDERSON: The curtailments that took place during 2003/2004 were all for upstream supply related reasons and all of those customers were offered supply under an alternate service arrangement. So, no customers who wanted gas were denied system gas.

MR. BOB PETERS: It may be that they just had to pay a greater amount for it, if they wanted it?

MR. BRENT SANDERSON: It was on the prevailing market price that we could acquire the supply on the given day.

MR. BOB PETERS: In terms of the supplemental gas that was supplied, the firm customers were served first with the primary and supplemental gas and then what was left over would end up flowing to the interruptible customers?

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

MR. BOB PETERS: Do you recall the billing percentages, Mr. Sanderson, or Ms. Derksen, as to what firm customers were supplied with, in terms of, supplemental gas?

MS. KELLY DERKSEN: Yes, there were a number of changes through the year. We started at 96 percent and 4 percent supplied to firm customers and that was on November 1st of 2003.

On February 1st of 2004, we moved to billing at 100 percent and zero for the firm customers and, and -- and that billing percentage still exists for the firm customers. It's anticipated that it will change effective November 1st of this upcoming year.

MR. BOB PETERS: Did the billing percentage for interruptible customers change as well?

MS. KELLY DERKSEN: Yes, sir, it changed also a number of times.

MR. BOB PETERS: And do you have those numbers at hand?

MS. KELLY DERKSEN: On November 1st of 2003, the interruptibles were billed at 92 percent and 8 percent primary, versus supplemental, that changed to ninety-eight (98) and 2 percent on February 1st of 2004, and we changed it to sixty-three (63) and 38 percent on August 1st of 2004. Sorry, sixty-two (62) and 38 percent, do the math, it needs to add to a hundred (100).

MR. BOB PETERS: Can you explain to the Board in dealing with your firm customers, why the billing percentage between primary gas and supplemental gas changed?

MR. BRENT SANDERSON: Load requirements for the firm customers during the winter were such that we were able to supply their load requirements during the peaking season with a higher percentage of primary gas than was forecast. And as a result, in order to balance overall billings with underlying purchases by the end of the gas year on October 31st, 2004, the shift in their billing percentage to 100 percent primary and zero percent supplemental was required at February 1st.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Sanderson, from that last answer are you telling the Board that in a -- in a particular year, if you're able to meet all of your load requirements with primary gas, the percentage of supplemental gas will be zero?

MR. BRENT SANDERSON: We haven't encountered such a year, but, yes, that would be the case. The -- the shift in the billing percentages for the firm customers to a 100 percent primary and zero percent supplemental at February 1st, shouldn't be taken to indicate that we were able to supply a 100 percent of the load during the entire year with primary gas.

It's just that that was the adjustment and the percentages required to balance over the course of the entire gas year to the underlying split of purchases between primary and supplemental.

If you'll remember during the November 2003 to January 2004 period, they were being billed at 96 percent primary and 4 percent supplemental, so they will -- the average -- we'll average it out. And I don't have the number in front of me, but there will be a portion of their load during the course of the year that was supplied with supplemental gas.

MR. BOB PETERS: Is it correct that in that answer, Mr. Sanderson, that you by July -- sorry, by October

31, you want to have your -- your load balanced out in terms of what you require from primary gas suppliers as well as supplemental gas suppliers?

MR. BRENT SANDERSON: What we're trying to achieve is a balance between how we've billed customers for primary and supplemental gas. We would like those overall percentage splits in the billings to balance to the underlying percentage split in the purchase requirement that we incurred in order to serve those customers.

MR. BOB PETERS: In Ms. Derksen's answer to me on similar questions for the interruptible customer class, Mr. Sanderson, she indicated that relatively recently you have moved to a significant percentage of supplemental gas, as opposed to primary gas.

And if I did the math and heard the numbers, it was 62 percent primary gas, 38 percent supplemental gas for the interruptibles?

MR. BRENT SANDERSON: Yes, for the period from August 1st, 2004 to October 31st, 2004.

MR. BOB PETERS: Can you explain why this -- this large adjustment was needed?

MR. BRENT SANDERSON: Well, in order to -- to illustrate why we needed to make the change of that magnitude we need to go back to the adjustment on February 1st, 2004.

We -- we want to, if at all possible, we want to restrict our adjustments in the billing percentages to the beginning of each gas quarter, in order to minimize customer confusion on the bills and so forth.

So, in order to determine whether we needed to make a billing percentage adjustment on February 1st, at that point, we had actual results up to -- the end of December 2004, pardon me, December 2003.

Combining those actual results with forecast results for the remainder of the year indicated the required adjustments to the billing percentages in terms of increasing the interruptibles primary gas. Percentage and decreasing the supplemental percentage because, to that point in the winter, we had been able to supply interruptible customers' requirements with the greater percentage primary gas than was indicated in the original forecast due to the nature of their actual loads.

Weather being what it will, we had no sooner low -- increased their primary gas percentage and lowered their supplemental percentage, we were faced with an extremely cold January and such that there is a much greater supplemental requirement for the -- in order to serve the interruptibles than was forecast.

So it's throwing our results the opposite way to what we were looking at, at the end of December.

So, incorporating those actual results and looking ahead to the next commencement of the next gas quarter beginning May 1st, 2004, we combined our actual results to the end of April 2004 with forecast results to the end of the gas year, to October 31st. And a reduction in the interruptible customers' primary gas percentage was indicated along with an increase in their supplemental gas percentage, but not nearly to the magnitude of what we were looking at as of August 1st, if we were to delay the adjustment.

There is special consideration this year in that the interruptible customer supplemental billed rate was significantly higher than their base rate due to a collection rate rider that was in place to recover past under-collected costs related to supplemental gas in prior period.

So, in order to increase their supplemental billing percentage at May 1st, in order to balance their billings and their underlying purchases, we felt that it would have placed a -- an onerous burden on the interruptible customers due to the fact that their supplemental gas billed rate was on the order of twice what their primary gas billed rate was at the time.

So we looked at what the adjustment and the percentages would be if we delayed or deferred the adjustment and the billing percentages to October 1st and balanced over a three (3) month period, as opposed to the six (6) month period beginning May 1st. Because the commencement of the gas quarter beginning August 1st, 2004, our expectation was that these -- this collection rate rider on their supplemental rate was going to drop off July 31st as per the Board's Order last year.

The -- these collection rate riders were to expire July 31st, resulting in a -- roughly a neutral bill impact for the interruptible customers because at that point, commencing August 1st, the primary gas billed rate and the supplemental billed rate would be roughly equal.

So it was a -- a judgment between undertaking a smaller magnitude of a billing percentage adjustment on May 1st which would translate into a material financial impact for the interruptible customers. Or we had the option of delaying that adjustment to August 1st which would give the appearance of a -- a much larger adjustment because we were adjusting, or balancing, over a smaller three (3) month period and a very low load period, I might add as well.

This is mostly summer months we're balancing over and the loads are very low. So, the magnitude of the adjustment would be correspondingly larger. But we felt that was the superior course of action because minimizing the financial impact on the interruptible customers.

MR. BOB PETERS: Do I take from that answer, Mr. Sanderson, that over the course of the gas year, the annual percentage split that you've used, will equal the purchase percentage of each of those two (2) categories of gas?

MR. BRENT SANDERSON: Based on actual results we have to date, yes, we're on track to balance purchases and billing splits by the end of the gas year, yes.

MR. BOB PETERS: And even though you will balance on the annual basis, the supplemental gas PGVA has accumulated approximately $11 million owing to customers?

MR. BRENT SANDERSON: Yes, that's correct. That is partially affected due to the fact that our PGVA accounts are managed on a fiscal year basis on the period running from April 1st of one (1) year until March 31st of the following year. Yet we're forced for operational requirements to manage billing percentages on the gas year basis, that being November 1st to October 31st, so there's some disconnect between the way in which we're forced to manage deferral accounts for internal purposes and the way we manage our billing percentages for operational purposes.

MR. BOB PETERS: But if it's cyclical like that, Mr. Sanderson, why wouldn't you be able to correct that over the course of a -- over a cycle?

MR. BRENT SANDERSON: I'm not sure I understand the question.

MR. BOB PETERS: Well, let me -- maybe I didn't understand your answer to me before. But the -- are you saying that the reason that the PGVA for the supplemental gas becomes as large as it does, is because of the time period in which you have to calculate the balance?

MR. BRENT SANDERSON: No, I wouldn't say that. I would say that the reason for the lion's share of the balance is in the supplemental PGVA account, has to do with the fact that we incur the vast majority of our supplemental gas costs, during the winter period, yet we collect those costs from customers over the entire annual period.

So, to the extent that we don't incur the expected level of supplemental gas costs during a winter period due to loads being lower than normal, due to warmer weather and the like, we've collected a lot of those costs already in the year leading up to that point.

And so very quickly, a large deferral balance can be generated if weather is dramatically warmer than normal or colder than normal, with a corresponding change in customers requirements.

MR. BOB PETERS: When we talk about the impact it has on customers, Ms. Derksen and Mr. Sanderson, I've heard from your answers that there is a considerable disparity between what would be the base rate and the billed rate, as we move forward?

MS. KELLY DERKSEN: In our Application today, yes, there is.

MR. BOB PETERS: And the billed rate has in it the volatility issues that Mr. Sanderson just told the Board about, that arise dependant significantly on -- on weather?

MS. KELLY DERKSEN: There's two (2) components to the rate Mr. -- Mr. Peters, as I'm sure that you know. There's the base component and then the rider component.

The portion of the rate that Mr. Sanderson was referring to, with respect to the extreme volatility had to do with the base component. The rider has already been established and is known with a fair amount of accuracy at the time it was set.

So, there's also influences on it but, specifically related to Mr. Sanderson's discussions with you, it had to do with the base component.

(BRIEF PAUSE)

MR. BOB PETERS: But the price signals you're sending to -- to the customer, in terms of the volatility of the rates itself, is due to the rate rider and not the base rate, would you agree with that, Ms. Derksen?

MS. KELLY DERKSEN: Yes, I think it's the much greater contributor to the -- the issue.

MR. BOB PETERS: And in terms of that -- the volatility, I took weather as being a significant factor that would lead to a large balance in the PGVA, either positive or negative, you'd agree with that?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And to a limited extent, Mr. Sanderson has told the Board last week, that he's forecasting what it's going to cost him for supplementary supply out of Oklahoma and Louisiana, but there will be some price fluctuation in his forecast as well, that will lead to volatility?

MS. KELLY DERKSEN: I think that the much greater contributor to the problem is -- is whether price volatility certain is a -- is a consideration, but again, I think weather is the much bigger factor.

MR. BOB PETERS: Is there any contribution to this volatility on account of your changing the billing percentages?

MS. KELLY DERKSEN: The changes in the billing percentages affect the recovery or the refund of the rate rider that's attached to the base component of the supplemental gas rate.

And so to the extent that we change our billing percentages, say on February 1st, to 100 percent primary and zero percent supplemental, of -- of course, that's going to contribute to the fact that we don't completely recover a refund, the PGVA or the rate rider that’s currently attached to the base rate.

(BRIEF PAUSE)

MR. DARREN RAINKIE: Mr. Peters, I would add, that’s what’s superior about our new proposal, is recovering those PGVA amounts over total volumes, will help to, with certainty, to refund or recover, or with more certainty refund or recover those amounts. That’s one (1) of the inherent benefits in our proposal.

MR. BOB PETERS: Thank you for that, Mr. Rainkie, for that -- for that sales pitch.

What you’re saying though, Mr. Rainkie, is that to the extent that it’s not fully recovered from Mr. Sanderson’s answer, it would flow into a PGVA account or a deferral account for it to be -- to be recovered or refunded at a later date. And you’re saying you have a way to perhaps be more accurate in your PGVA refund or recovery mechanism?

MR. DARREN RAINKIE: It’s more -- I think it’s we have more certainty over what our distribution volumes will be than the supplemental volumes, because of the weather fluctuations. So, in my view, it’s a superior methodology to refund or recover that money.

MR. BOB PETERS: All right, well let’s turn to the specific problem in the few minutes we have before lunch then. And the specific problem, and it's maybe not a bad problem is that you have $11.1 million that you want to refund on account of supplemental gas rates that were charged to consumers last year, is that correct?

MS. KELLY DERKSEN: The answer is, yes, Mr. Peters. I don't want to get hung up on the $11.2 million or the $11 million that we're speaking of, only from the perspective of what that I do with all of the deferral balances is that I reallocate the costs that we incur, in terms of the deferral balances.

And so to the extent that we have some unrecovered prior period supplemental residuals, that's going to reduce the $11 million to somewhere in the order of magnitude of $9.2 million, and that's the amount that we propose to refund to the distribution to customer charge.

MR. BOB PETERS: Can you turn to Tab 8 of the book of documents, Ms. Derksen, and just show me where you have the -- the supplemental gas PGVA balance from previous years that you want to offset against the $11.1 million that we talked about?

MS. KELLY DERKSEN: You don't see a specific amount related to supplemental gas on this particular schedule. But what I have -- I have information that divvies up the prior period residuals into its -- its component, supplemental gas being one (1) of them.

And if I take you then to Schedule...

(BRIEF PAUSE)

MS. KELLY DERKSEN: To Schedule 8.4.0.

(BRIEF PAUSE)

MS. KELLY DERKSEN: On line 39 of that schedule, you can see the -- the net recovery in the supplemental PGVA for both firm and interruptible customers. For firm customers in this case it's $9.2 million. And that is composed of the 2003/04 PGVA -- supplemental PGVA balance as at March the 31st of 2004, plus carrying costs, plus any unrecovered or unrecovered amounts from prior years, as it relates only to supplemental gas.

MR. BOB PETERS: So the amounts shown on the Schedule 5.1.0 in terms of deferral account balances from prior periods, that's a net number, and -- and you've just now taken out the supplemental gas portion and offset it against the surplus that exists in the PGVA?

MS. KELLY DERKSEN: Yes, sir. Yes.

MR. BOB PETERS: And has the -- has the adjustment that's been made on Schedule 5.1.0, is that now reflecting the refund of the PGVA of about $9.2 million on account of supplemental gas?

(BRIEF PAUSE)

MR. BRENT SANDERSON: I'm hoping that I understand your question correctly, Mr. Peters. If we look at line 5 of updated Schedule 5.1.0, we see the $11.1 million credit balance or amount owing to customers, as a result of amounts owing to customers, relating to supplemental gas for the 2003/2004 fiscal year.

If you'll move up to line 2 above that and there's a $1.7 million credit balance there. Inherent in that balance is a debit amount of -- on the ballpark and Ms. Derksen could correct me, but in the neighbourhood of $2 million related to unrecovered supplemental gas deferral balances from periods before 2003/2004, which are being carried forward.

So, the net of those two (2) will be the $9 million and change, Ms. Derksen referred to on her schedule and -- and she can reiterate the number of that schedule she referred to.

MR. BOB PETERS: I think we have it here. So with that answer, Mr. Chairman and Board Members and recognizing the hour, I would suggest this would be an appropriate time for the lunch break.

THE CHAIRPERSON: Thank you Mr. Peters. Thank you to the Panel. We'll see you all back at 1:30. Thank you.

--- Upon recessing at 12:04 p.m.
--- Upon resuming at 1:34 p.m.

THE CHAIRPERSON: Mr. Peters...?

MR. BOB PETERS: Thank you, good afternoon. Before lunch, Mr. Chairman, and, Board Members, we left off with the enviable issue of how to refund $9.2 million and I think we decided it wasn't going to all come to me, so we were going to look at some alternate method for doing that.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: And to that end, this $9.2 million, Ms. Derksen, arose out of the supplemental gas PGVA account, correct?

MS. KELLY DERKSEN: From different years, yes.

MR. BOB PETERS: And when you say different years, you have netted against it all outstanding PGVA balances that are attributed to supplemental gas and you're left with $9.2 million approximately?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And you are now asking this Board to allow you to prepare a rate rider that will refund monies to the different customer classes, and included in their volumetric charges for all customers, except -- except for the mainline customer?

MS. KELLY DERKSEN: In the volumetric distribution to customer charge, yes, except for the mainline class.

MR. BOB PETERS: All right, you've jumped ahead of me. Whereas normally you would come to this Board and say it was a supplemental gas charge, we've over collected, we would like a supplemental gas rate rider to refund it, that would be the normal fare that this Board has seen in past years?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And you're coming to them this year saying it is a supplemental gas surplus that we have, we want to refund it, but not in the supplemental gas rate, we want to do it through the distribution to customers' volumetric charge?

MS. KELLY DERKSEN: Yes, that's our proposal.

MR. BOB PETERS: And that is the proposal, except for the few customers in the mainline class to -- to which -- to whom are -- who are entitled to a refund of some supplemental gas charges?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: Is this a one (1) time only proposal, or will this be an ongoing request of the Board, Ms. Derksen?

(BRIEF PAUSE)

MR. DARREN RAINKIE: Mr. Peters, maybe I can give Ms. Derksen a rest here, she's been talking quite a long time and my load factor's pretty low in the last few days.

So, I think we think it's a good solution, and it may indeed be a robust solution that will last for a while to come. I don't think we'll -- we'll stop looking at other possible solutions, but I think let's try it this year and see how it pans out, I think it's got a -- as I mentioned before, some good merits to it. And if we come across something else that's better, we might end up proposing that in the future.

MR. BOB PETERS: At this time it's a -- it's a one (1) year Application then, Mr. Rainkie, and if it's going to continue, or it's going to change, the Board would be made aware of that in any future applications?

MR. DARREN RAINKIE: That's right, it directly affects the calculation of rates, so of course the Board would have to approve it, before we implemented anything different.

MR. BOB PETERS: Why, Mr. Rainkie, has the Corporation focused on refunding this supplemental gas surplus as a rate rider through a distribution rate?

MR. DARREN RAINKIE: There's primarily two (2) reasons I think, as we stated in the material.

Number one (1), it allows the supplemental base rate to be a pure rate unaffected by a rate rider. And that will -- that should ensure that the supplemental rate isn't that much different than the primary gas rate. And so it's from a market responsiveness point of view, it provides a good signal to the customer.

If you've looked at some of the material from the past couple of years, that supplemental billed rate has gone all the way from about ten (10) cents to over forty (40) cents. Whereas the underlying cost has been maybe twenty-four (24) to twenty-six (26) cents, which isn't that much different than the primary gas rate. So it provides for a more market responsive supplemental gas base rate.

As well, it can -- it's a better methodology to refund or recover any supplemental gas PGVA, because we have a greater certainty over the distribution volumes that we're going to have in any one (1) particular year, than the supplemental volumes, which we've heard are subject to weather variances.

MR. BOB PETERS: Do you agree with me, Mr. Rainkie, that it -- it does to some extent distort the distribution costs?

MS. KELLY DERKSEN: I would agree that you're adding a cost that is accumulated in a different way into a distribution rate, but I think that the bigger of the issue is that it really distorts the base rate for supplemental.

And so I guess you have to outweigh one (1) versus the other, and in our opinions, putting that supplemental rate rider into the distribution rate is the preferable alternative at this point.

MR. BOB PETERS: If I carry that answer further, Ms. Derksen, would it not then make sense to put the primary gas PGVA into the distribution rate as well?

MS. KELLY DERKSEN: The trouble with the primary gas PGVA, of course, is that that is a rate that is subject to competition by -- by brokers and we would open up a whole can of worms by proposing to include the -- the primary gas PGVA into the distribution rate.

You have one (1) set of customers who pay for the primary gas PGVA and you would distort the -- the customers who are responsible for that, by adding it to the distribution account.

MR. BRENT SANDERSON: I'd also like to add that the primary gas billed rate isn't subject to the same degree of distortion as a result of the rate rider as the supplemental rate would.

Our primary gas purchase volumes are subject to very much less variability in response to weather variances, as compared to the supplemental purchases.

So where we can see a supplemental rider resulting in a supplemental billed rate that is double the underlying base rate or resulting in a negative billed rate, we never see anywhere near to that -- that degree of distortion, for want of a better term, in terms of the primary gas billed rate.

It -- the primary gas rate rider represents a much smaller portion of the overall billed rate.

MR. BOB PETERS: All right. Thank you for that. When -- when you acknowledged, Ms. Derksen, that, to some extent, it does distort the distribution costs, it would be to the same extent then -- it would -- it would mask the impact of the supplemental gas rate rider. You wouldn’t see it at all under your proposal?

MS. KELLY DERKSEN: That’s true, there is -- there would be no transparency in terms of that particular component on the bill. Although I guess it -- one could argue that a customer doesn’t see that particular component on the bill to begin with, so...

MR. BOB PETERS: In terms of other options that might be considered, you considered that for the mainline customer, you would like to show a specific line item on the bill which would be their supplemental gas refund rider in this case?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And how many customers was that again?

MS. KELLY DERKSEN: I believe there's only four (4) customers that would be entitled to that refund.

MR. BOB PETERS: If you can put a separate line item on the -- on the bills for the mainline customer, could you do the same for the other customer classes as well and treat it as a separate line item?

MS. KELLY DERKSEN: Certainly one (1) of the options that we considered when we were looking into this issue further this past year, one (1) of the big drawbacks in doing that is -- you know, we've subjected our residential type customers and other customers on our system to a whole lot of changes in the last five (5) years in terms of what the bill looks like. And trying to educate customers as to the different changes that have transpired in this province since then.

And I think one (1) of the big -- the drawbacks in adding that separate line item on the bill for two hundred and fifty thousand (250,000) customers is trying to explain to customers and help them understand what that might be related to.

And -- and I think that's probably -- maybe more than what customers can -- can handle at this point.

MR. DARREN RAINKIE: I would add, Mr. Peters, that -- let's put some context around this. Out of a 500 million plus revenue requirement, supplemental gas forecast costs might be -- range between fifteen (15) and 18 million. So to have another line item for a very small slice of the bill with the issues that Ms. Derksen has just described, I don't think is -- I think it's just adding more to the aggravation.

The whole reason for this proposal in the first place is -- is because we've had some negative feedback from customers that -- you know, with billing percentages changes -- changing that they're not understanding why supplemental gas is priced so differently than primary gas.

So, I think if we went that route of adding another line, we're simply adding to our customer relation issues for a slice of the rates that's 16 million out of, you know, 520 million.

So I think it's important to have some context in that discussion.

MR. BOB PETERS: I've got your answer, Mr. Rainkie, and Ms. Derksen. I'll come back and talk to you about the -- the bill format when I talk about terms and conditions, but I take it that your answer was you just didn't want to add an additional line item to what's already expected to be on your consumer bills for your customers?

MR. DARREN RAINKIE: That -- that's right. The reason we're proposing a little -- a slightly different from the mainline customer is it's very easy to do. We have a -- a separate system that bills the -- the larger volume customers, so it's much easier to do that than to program our larger billing system for two hundred and fifty thousand (250,000) customers.

MR. BOB PETERS: Is it only Centra's transportation service customers that don't take supplemental gas from the Utility?

MS. KELLY DERKSEN: Yes, that's true.

MR. BOB PETERS: Can you confirm to the Board, Ms. Derksen, that in terms of the net effect, there will be no difference for each and every customer, whether you had this included as a supplemental gas rate rider, or whether you put it through the distribution rate?

MS. KELLY DERKSEN: There is no impact -- any additional or incremental impact associated with this treatment, this is simply a rate design or a bill presentation matter.

MR. BOB PETERS: So, there's no difference between customer classes as to how you're proposing to treat this, that is that the customer classes will have the same amount of money to be refunded. And then when you get down to rate design, each customer themselves will receive, at least theoretically, the same refund under either method?

MS. KELLY DERKSEN: Yes, there is -- there is -- it's actually just taking one (1) amount and one (1) rate and transferring it to another, it's that simple.

MR. BOB PETERS: Does this -- does this proposal that you put forward before the Board have any impact on the broker's ability to market against Centra's gas?

MS. KELLY DERKSEN: No, sir, the supplemental supply is -- is a gas supply that Centra provides to all sales and WTS customers. The only customer type of course that doesn't take supplemental, would be transportation customers. So, it does not impact a broker's ability to compete with Centra's primary gas component.

MR. BOB PETERS: And I'm just going to follow up on something Mr. Rainkie said, but will this change that you're proposing, impact the billing percentage changes that you are now required to make throughout the year?

MS. KELLY DERKSEN: It's not going to impact them in terms of -- I mean, really the billing percentages are an operational issue where we have to balance out our supply requirements.

What it will do is change -- when we make a billing percent change of course, because your supplemental rate and your primary gas rate are closer to one (1) another, in terms of a price, the billing percent change will have less of an impact to the customer at the time the billing percent change is made.

MR. BOB PETERS: Just to conclude in this area on the main line customers. By incorporating the supplemental gas rate rider onto their bill, if you put it into their -- into their supplemental gas rate, did I understand your evidence that you would have in some cases a negative billed rate?

MS. KELLY DERKSEN: If we put the supplemental refund rider in the distribution rate for the main line customers, because their distribution rate is so small, their base and their rate rider together is even smaller than the negative rider from the supplemental gas component. It does result in a negative rate.

So you're either going to have a negative distribution rate for those customers or add a line item called, you know, your supplemental refund, is really going to amount to the same thing.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, I want to turn with you please to your proposal before this Board dealing with the high volume firm customer class in specific, and as I read the Application, you're asking this Board to change the method of determining the demand levels for purposes of billing the high volume firm customers?

MS. KELLY DERKSEN: Yes, that's true.

MR. BOB PETERS: And to understand what you're asking for, I want to make sure I understand what you presently are doing. And would it be correct that presently the demand that you use with respect to high volume firm customers, is determined based on their average monthly demand in the peak month?

MS. KELLY DERKSEN: That's true, in terms of billing demand for the high volume firm class, we take -- we find the customer's peak month, generally speaking it's the month of January for most customers. We add up all the daily consumptions of that month, and we divide by the number of days, in that case it would be thirty-one (31) days.

And that would tell us, on average for that month, what they would consume and we would multiply that volume, that average amount, by the demand rate on the bill and that would tell a customer what their responsibility is for that month for the demand component.

MR. BOB PETERS: And the demand rate that is set in the peak month, it has to be a winter peak month not a summer peak month. Is that correct?

MS. KELLY DERKSEN: That’s true.

(BRIEF PAUSE)

MR. BOB PETERS: The time period in which the demand is -- has been determined that is used presently by the Corporation is from the winter of 2003/04. Is that correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And so that average monthly demand that you charge the high volume firm customers would have been set somewhere between November of 2003 and March of 2004?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: In terms of what you are now asking the Board to change, Ms. Derksen, is that you want new rates effective November 1st of 2004 and that would include a new demand rate for this customer class, correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And the new rate that you are proposing to this Board for November 1st of 2004 has been forecast by the Corporation to be the actual peak for the winter of ’04 and ’05. Am I correct?

MS. KELLY DERKSEN: Yes. Perhaps maybe I -- I should explain what we're proposing. This issue is not about revenue requirement. We -- we have set what the revenue requirement amount for demand should be as part of the 03/04 General Rate Application with the exception of -- of the gas costs that are proposed in this Application.

So that amount is -- is being forecast or is known and it's -- it's a matter of taking that revenue requirement that's ultimately approved through this Application and dividing by billing determinants.

Now, we're proposing that those billing determinants that you divide by, would be the actual -- the billing determinants that are forecast on an actual peak day basis for the 04/05 year. Because that would then allow us to bill demand on the basis of a customer's actual peak day for the 04/05 year, beginning on November the 1st of 2004.

MR. BOB PETERS: And while that helps the Board understand where the -- where the rate has been -- how the rate has been determined, the determinants that you're going to use on November the 1st will remain the -- the old billing determinants, if I can use that. That is, the average monthly demand.

MS. KELLY DERKSEN: No, sir, that's not correct. We are proposing as part -- two (2) things have to happen -- two (2) things have to happen for this issue to take effect.

The first thing that has to happen is that a customer’s actual -- average demand needs to change to their actual demand. So, instead of billing based on an average of the peak month, we need to start billing customers on an actual peak day.

The second thing that needs to happen is that your rate needs to change in order for that to reflect that change, because if I have a hundred dollars ($100) that I need to collect from that customer class, and under an average peak day methodology I had fifty (50) units, I would be charging a two dollar ($2) rate.

If I am billing on an actual peak day basis, I take that same hundred dollars ($100), because it’s not a revenue requirement issue, it’s a -- it’s a rate design issue. I would then divide by the number of actual billing determinants, which might be a hundred (100) units for example. And I’m now going to be collecting a lesser rate, a dollar ($1).

So, what has to happen or what our proposal is on November 1st is that customers have already been billed for the 03/04 year, on the basis of average peak -- average of the peak month.

We are today billing on the basis of average of the peak month. On November 1st, because my rate that I -

- we have incorporated in this Application reflects actual billing determinants, we need to then begin billing on an actual peak day, November 1st. And those actual billing determinants that I've included in this -- in this Application are what we have forecasted the high volume firm demand class to use on an actual peak day basis, for the '04/'05 year.

MR. BOB PETERS: How do you forecast what that actual peak is going to be, Ms. Derksen?

MS. KELLY DERKSEN: I know the name is -- is a bit -- is a bit silly, because we're forecasting an actual billing determinant. But basically what our load forecasting people do, as what I understand, is they look historically to see what every customer in the high volume firm class uses in terms -- or sets in terms of an actual peak day.

And we will use that information to forecast for the '04/'05 year, and make any changes as we are aware, from individual customers, as a result of process changes or anticipated changes to their -- their business operations.

MR. BOB PETERS: Do I take from that answer that while you may forecast what their peak actual will be, you may be wrong?

MS. KELLY DERKSEN: Correct, it's a forecast of what we expect them to use on an actual peak day basis.

MR. BOB PETERS: And when it comes time to determining what the actual peak is based on actual results, will that result in your changing the billing determinants at that time?

MS. KELLY DERKSEN: No, Mr. Peters, this is no different than forecasting the volumes to be used as a billing determinant. When you determine the distribution to customer charge, Centra accepts the fact that we may be out in terms of our forecasting. And so forecasting demand units is no different than any of those -- the other forecasting of loads that -- that we incur or that we provide at the Utility.

MR. BOB PETERS: And what happens to the -- if you're incorrect in your forecast, which I suppose you expect you will be, but you just don't know which way, what will happen to the resulting impacts that customers will pay, that will be either greater or less than what their -- what their forecast peak will be?

MS. KELLY DERKSEN: What occurs as a result of a not a perfect forecast is that the company will either over collect in terms of that particular cost component on the bill, or under collect, depending on, you know, if -- if we've over or under forecasted.

But this is again, no different than forecasting volumes in -- in the SGS class, to the extent that we've over or under collected, we accept that risk, and

-- and that’s how it’s dealt with.

MR. BOB PETERS: When you say we accept that risk, does that risk translate financially into the PGVA?

MS. KELLY DERKSEN: There’s two (2) different cost components that we’re talking about here, one (1) is an upstream demand component, and one (1) is a downstream demand rate.

The upstream demand component is base -- is basically the demand costs that we incur on TCPL and ANR and so forth, and all of those costs do get tracked in a PGVA. So the company and the customer is held harmless to the extent that we have not forecasted load or demand exactly as what happens.

On the downstream side of the business, or the downstream demand component of the bill, those are -- most of those costs, with the exception of Monell Pipeline, which is considered a gas cost, those are not subject to a PGVA. So, to the extent that we over or under forecast that, will directly hit our bottom line.

MR. BOB PETERS: In terms of --

MS. KELLY DERKSEN: I’m sorry, I just wanted to add a comment that -- I mean, that’s no different than what we have under the method that we use for billing today for the high volume firm class, which is on the basis of an average of the peak month.

(BRIEF PAUSE)

MR. BOB PETERS: In dealing with those upstream demand costs that would flow into the PGVA, Ms. Derksen, and capture any differences before forecast and actual, that would keep the class whole, would it not, as opposed to individual customers within the class?

(BRIEF PAUSE)

MS. KELLY DERKSEN: Yes, that's true.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, just want to make sure that I'm clear on the concept of your forecasting the peak for a customer in the high volume firm class. You've acknowledged that your forecast may result in an error when it comes time to determine what is the actual peak, correct?

MS. KELLY DERKSEN: Yes, that's true.

MR. BOB PETERS: And did I hear you say through answers to Ms. Murphy this morning that you will allow customers an opportunity to re-shape their loads and determine what their peak will ultimately be this coming winter?

MS. KELLY DERKSEN: I think what we had intended to say, and maybe we didn't say very clearly is that if the Board accepts our proposal to implement actual peak day billings for the high volume firm class on November the 1st of 2004, we will look prospectively at each customer in that class.

And we will begin billing them on actual peak day only when their actual peak day exceeds their average peak day that was established in the 03/04 winter period. Recognizing that 60 percent of customers will exceed -- their actual peak will exceed the peak that was determined in the oh -- the average peak that was determined in the 03/04 year.

So to the extent that the customer does not want to be billed on an actual peak day basis, based on what they occurred -- incurred last year, they will be able to avoid that and perhaps control what they use for the 04/05 year in terms of setting a peak demand.

MR. BOB PETERS: So you're only going to change when the actual peak exceeds the average from the past year?

MS. KELLY DERKSEN: Correct. If I have a customer, for example, in that class who's average peak is fifty (50) -- is fifty (50) units established in 03/04, and that customer then -- his actual peak in November of 2004 is a hundred (100), he will then be billed at a hundred (100) units in November.

If that -- if his peak is twenty-five (25) in the month of November, on an actual basis, he will not get billed on that actual peak demand. He will continue to be billed on the fifty (50) that he established on an average peak demand from the 03/04 winter period.

MR. BOB PETERS: That'll end up being re-initialized the following year, if you -- if you continue on this methodology, and it's approved by the Board?

MS. KELLY DERKSEN: Once eleven (11) months is passed for each individual customer, we need to re-establish their peak in any regard. So at some point during the 04/05 winter season, a customer will begin being billed on an actual peak day basis.

From -- based on the results of last year, over ninety (90) -- over 90 percent of our customers were billed on an -- on an actual peak day basis by the month of December.

(BRIEF PAUSE)

MR. BOB PETERS: In the examples you've given me, Ms. Derksen, a customer would not be based on an actual peak for the next eleven (11) months, so long as their actual peak is below the average peak. Have I -- do you agree with that?

MS. KELLY DERKSEN: That's precisely what I'm saying, yes.

MR. BOB PETERS: All right. And what happens, then, in a situation where -- in the -- in one (1) month, the customer exceeds the average peak and establishes a new actual peak. You would, at that point in time, revert to the methodology you're proposing before this Board?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: What would happen if in two (2) months time that customer then established a -- a new peak again that in the second month was higher than the peak in the first month, and the peak in the first month was higher than the average peak set last year?

MS. KELLY DERKSEN: That's the same thing as what happens generally today, is if a customer in the second month exceeds their peak of the first month, they would be billed on the higher peak of the second month.

MR. BOB PETERS: When you've said to me, and I will say on more than one (1) occasion, that it's not a revenue requirement issue, what you're telling the Board is that the demand costs do not change because of the method that you are using to bill the demand cots, is that correct?

MS. KELLY DERKSEN: That's what I'm saying, that's correct.

MR. BOB PETERS: And the allocation of demand costs to customer classes does not change with the proposed change in the billing determinants either?

MS. KELLY DERKSEN: That's correct.

MR. BOB PETERS: So this isn't a cost allocation issue, it would be considered a rate design issue, would you agree with that?

MR. BOB PETERS: Yes, I would.

MS. KELLY DERKSEN: And this morning I believe, we looked at Tab 14 of the book of documents, and just so we can focus in on the high volume firm class, maybe you could turn to Tab 14 of the book of documents that was prepared for Board Counsel, Schedule 7.1.0. And we see on line 4, I believe, the upstream demand costs for high volume firm customers is approximately $3.59 million, correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And then if we go down to the downstream costs on line 9, there's an additional thirteen thousand six hundred dollars ($13,600) correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: When you told the Board before that the upstream costs would flow through the PGVA and the customer class would be kept whole, you were referring to the $3.6 million number found on line 4 of

Schedule 7.1.0, is that correct?

MS. KELLY DERKSEN: It's partly correct. The thirteen thousand six hundred dollars ($13,600) that is a result of an allocation of Monell Pipeline costs, that too is subject to a PGVA, and no different than the $3.5 million on the first line.

MR. BOB PETERS: Which amount of money then is at risk, as you put it?

MS. KELLY DERKSEN: Don't forget that this -- what we're showing on this particular Schedule 7.1.0, is an allocation of only gas related costs. To the extent that we have non-gas costs which are not identified on this schedule, those are the costs that would -- would be at risk for a load forecast that deviates from actual.

MR. BOB PETERS: And I won't see those until Mr. Warden brings his General Rate Application before the Board later this fall, is that correct?

MS. KELLY DERKSEN: You won't see those on this schedule, you'll certainly see them in the rate Schedule 8.2.0, because of course the rates encompass all of the costs, both non-gas costs and gas costs.

MR. BOB PETERS: While we're on Schedule 7.1.0, Ms. Derksen, can you explain under line 16, when we look under the high volume firm class, what the allocator is that results in the -- the monthly determinant of ten thousand and fifty-eight (10,058) 10-3-M 3 day?

MS. KELLY DERKSEN: Mr. Peters, those are the billing determinants that we use to divide the total revenue requirement or the total demand costs by. So, as I indicated to you previously, what we do in terms of a forecast, is that we look at each individual customer in that class and we forecast what we anticipate they will set in terms of a peak for the '04/'05 year.

The ten thousand oh fifty-eight (10,058) and then the eleven thousand five forty-one (11,541), that you'll see a couple lines below, those -- those are our forecast of what we expect the peak -- actual peak day consumptions to be, compiled all together for each customer in that class.

MR. BOB PETERS: So that's the forecast peak for -- for high volume firm?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And is it also the forecast peak for say the interruptible class, or the mainline class?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: Don't want to dwell on it, but when I get to the special contract customer, and I know I'm diverting a little bit from the high volume firm here, but I -- I note that the downstream resulting unit charge, how is that equated through to the demand costs for this -- for this customer class?

MS. KELLY DERKSEN: The only cost that's subject to that particular customer, as a result of this type of application is with respect to Monell Pipelines, as it relates to -- to demand costs. And so the twenty-nine thousand three hundred dollars ($29,300) that you'll see in the downstream demand line is the special contracts allocation of Monell pipeline costs.

We would then divide by what we expect that they would use in terms of an actual peak. And we come up with a number, because their rate treatment is slightly different than the other customer classes, we actually just take the twenty-nine thousand three (3) -- three oh four (29,304) and we divide by twelve (12) because they pay it in equal instalments through their basic monthly charge.

MR. BOB PETERS: All right. Thank you for that explanation. Turning back to the high volume firm class, I want to run through some historical information and find out if the Corporation agrees with -- with my research.

But you've already told the Board that back in 1996 the Board held a hearing into the Cost of Service study and the cost allocation methodologies of Centra, correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And that led to Board Order 107/96?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And it's -- is it your recollection that through that Order, two (2) new customer classes were developed including -- which were the high volume firm and the main line customer?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And you've told the Board that the three (3) part rate structure arose from that Hearing and, again, that was based on your recollection that it was recommended by the consultant and ultimately accepted by the Board?

MS. KELLY DERKSEN: I believe that's what happened, yes.

MR. BOB PETERS: And before the three (3) part rate structure was in place, all of those demand costs would have been recovered in the volumetric charges to those customers?

MS. KELLY DERKSEN: To my knowledge, yes.

MR. BOB PETERS: You've told the Board earlier today that you don't have three (3) part rates for the LGS and the SGS classes, because they're relatively homogeneous, is -- is my word, but relatively similar demand and load patterns.

Would you agree with that?

MS. KELLY DERKSEN: I think that's one (1) of the reasons. I think the customer acceptability and understandability issues is another of the reasons. And then, of course, the cost of implementing or installing demand meters or some kind of metering device that allows us to read on an -- on a daily basis.

The cost related to installing that on two hundred and fifty thousand (250,000) customers would be prohibitive. So I think that's another reason.

MR. BOB PETERS: Do I gather that in the high volume firm class, the Corporation has determined that the demand levels are -- are not similar for all customers within the class and therefore you've decided that the three (3) part rate is -- is the more appropriate way to deal with that discrepancy?

(BRIEF PAUSE)

MS. KELLY DERKSEN: I think that's the intent behind the three (3) part rate, yes, is to re-shape your revenue requirement so you're -- you're recovering that revenue requirement from those customers who cause the costs in that class to be incurred.

MR. BOB PETERS: And when we talk about how customers cause the costs to be incurred, you could have a situation where a customer has a constant load, three hundred and sixty-five (365) days a year, and that load would be different than a customer who uses three (3) times as much gas on the peak day, as that customer would on their average day and those would be different load patterns?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And under a two (2) part rate structure, the customer that uses the most gas, or consumes the most volume, would pay more in volumetric charges which would have embedded in them a demand cost under a two (2) part rate structure.

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: So the inequity would be that a customer may not cause most or any of the demand charges, but would end up paying through the volumetric charge, whatever demand charges were embedded in the volume?

MS. KELLY DERKSEN: Certainly they would cause some of the demand costs, but probably not the extent to which that they would be paying for through a two (2) part rate.

MR. BOB PETERS: And under a three (3) part rate structure, the high load factor customer can end up paying less of the demand costs compared to the low load factor customer?

(BRIEF PAUSE)

MS. KELLY DERKSEN: It’s the total -- it’s the unit cost that would be reduced for the high load factor customer. I mean, if a customer uses -- you know, a hundred (100) cubic metres of gas in comparison to another customer who only uses ten (10), their annual bill will be more, because they use more of the system. But their unit rate will be less than what the customer who pays -- who uses ten (10) cubic metres of gas in a year.

MR. BOB PETERS: Okay. Back to Order 107 of ’96: That’s a time when once you recommended and the Board accepted that there be a three (3) part rate structure, you had the concern as to how to implement that in the rates to consumers; was that correct?

MS. KELLY DERKSEN: Certainly we had the concern of how to implement that for the high volume firm class, recognizing that we did not have the appropriate demand metering in place to be able to read their consumption on a daily basis.

MR. BOB PETERS: And back in 1997, these demand meters that you’re talking about, were being installed, and it was the Corporation’s plan to install them for all high volume firm customers?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And was that a cost paid for by the customer, or was that a cost paid for by the Utility and then embedded in the rates?

MS. KELLY DERKSEN: It would have been a cost paid by the Utility, which ultimately would be embedded in the rates.

MR. BOB PETERS: And when the Board saw this matter back in 1997, the Corporation wanted to wait until it had the meters in place, but there was also a concern as to the actual quantum of demand costs that were going to be charged through to consumers; is that your recollection?

(BRIEF PAUSE)

MR. GREG BARNLUND: Perhaps, Mr. Peters, I may just fill in the blanks on that particular question, because I was involved in that aspect of it, and I think there's really two (2) issues that were dealt with, in terms of implementing the three (3) part rates. The first one (1) was the issue of getting the proper metering in place, and that we have just talked about.

The second issue in terms of implementation, was I believe our original proposal, contemplated a demand charge that recovered 100 percent of the capacity costs. And we acknowledge that there was going to be some rate impacts to certain customers as a result of that, so we had modified our proposal to include 50 percent of the demand and the capacity costs, and 50 percent to be recovered in the commodity charge.

MR. BOB PETERS: Thank you for that, Mr. Barnlund. It's perhaps the grey hair that -- that Ms. Derksen doesn't have, that allows you to refresh our memories on that.

But in terms of how that developed, Mr. Barnlund, the Board agreed that a three (3) part rate for high volume firm would be appropriate, but pending the installation of the appropriate telemetry, a proxy was going to be used, and that was going to be the daily average demand of the peak month; is that correct?

MS. KELLY DERKSEN: Yes, I would agree.

MR. BOB PETERS: All right. And -- and that -- that dealt with one (1) of the two (2) issues that Mr. Barnlund raised, and that was how do you measure what is the actual demand, pending the actual meters being installed?

MS. KELLY DERKSEN: Right.

(BRIEF PAUSE)

MR. BOB PETERS: When it came time for the telemetry -- when I -- when I say telemetry, you might have to help me, because I'm not sure I've ever seen one (1) of these, but this is a type of a meter that the company can access remotely?

MR. GREG BARNLUND: That's correct. The meter itself has got a -- essentially it's a computer on top of it that takes the information from the meter itself, and it has got the processing capability to be able to correct the meter reading for the appropriate pressure and temperature compensation. And then it stores that data, and it also is connected through the telephone system to our SCADA system, and we're able to remotely interrogate that meter for data, at least once a day.

MR. BOB PETERS: And other than maybe painting my house and wondering whether or not I can paint my gas meter, would I notice any difference between the -- the residential meter and these types of meters, Mr. Barnlund? Are -- are -- they're -- they're significantly different?

MR. GREG BARNLUND: I'd say they are significantly different. The residential meter is -- is very simple in comparison to the equipment that we were required to install for our large volume customers to be able to meet these requirements.

MR. BOB PETERS: Can you give me the relative -- your guesstimate as to the cost of a residential gas meter compared to one (1) that you would use for a high volume firm customer?

MR. GREG BARNLUND: I'd say that potentially a residential gas meter could be potentially about seventy-five dollars ($75) Canadian to purchase. An industrial -- the meter itself and the flow computer could be anywheres upwards of ten thousand (10,000) to twenty thousand dollars ($20,000).

MR. BOB PETERS: When I asked earlier how the costs of those meters were dealt with, were those costs allocated specifically to the customer class?

MS. KELLY DERKSEN: Yes, sir.

MR. GREG BARNLUND: So, the high volume firm customers and I've forgotten the number already, but seventy-nine (79), eighty (80), eighty-one (81), eighty-two (82), somewhere in that range, all of the cost of those meters would be borne by the customers in that class?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And likewise, the -- the mainline customers, they would pay their costs on an allocated basis for whatever the class requires for -- for meters?

MS. KELLY DERKSEN: Yeah, we have a -- we have a pretty good idea of what customers have what meters and the cost of those meters. So, to the extent that we can directly assign those costs, we do.

MR. BOB PETERS: Just, maybe I'm getting confused on that answer, Ms. Derksen, but when you say directly assign it, you mean directly assign it to the class?

MS. KELLY DERKSEN: Yeah, I should have clarified that. We know with a fair amount of certainty, what meters belong to what class, and the costs of those meters would be directly assigned to the class that causes the costs of those meters.

MR. BOB PETERS: Okay. And so if a brand new high volume firm customer showed up at your doorstep tomorrow, for which you had to install a new ten (10) to twenty thousand dollar ($20,000) meter, would that customer be expected to pay that cost, or would that be a cost that would flow to the entire class?

MS. KELLY DERKSEN: They may be subject to a feasibility study, depending on the circumstance. So, to the extent that there -- the rates today are insufficient to reflect the total costs to install service to that new customer, they may be required to pay a contribution.

But ultimately the cost of that meter would flow to the high volume firm class, for example.

MR. BOB PETERS: And when Mr. Barnlund separated the two (2) issues that are -- that are somehow interrelated in this matter, back in 1999 at your Cost of Gas Hearing, Centra filed a report on where it was with respect to billing demand determinants for the high volume firm class?

MR. DARREN RAINKIE: Mr. Peters, maybe I can help here, I think it was the 2001/'02 Cost of Gas that we filed that report. I think it was at the 1999 Cost of Gas Hearing that the Board directed us to file that report.

MR. BOB PETERS: And, Mr. Rainkie, since your memory is so good, back in 2001 and 2002, at your Cost of Gas Application you had all of your telemetry and your meters in place for the high volume firm class, correct?

MS. KELLY DERKSEN: I think other than maybe one (1) or two (2) customers that I would agree with your statement.

MR. BOB PETERS: All right, and even though you had the meters virtually all in place, Ms. Derksen, you didn't start using actual peak measurements back in 2001 and 2002, because you didn't make an application to the Board until the following year, which was the '03/'04 year?

MS. KELLY DERKSEN: Yes, this is really an issue that's subject to a general rate application, so we propose -- we proposed to postpone the -- the change in how we billed demand for the high volume firm class, until we had a general rate application.

MR. BOB PETERS: And when you had that general rate application, at least a couple of the Board Members may recall that you had two (2) changes before the Board, or two (2) different, separate requests that Mr.

Barnlund perhaps gave me a heads up on, and one (1) of them was to change the recovery from 50 percent of demand costs to 65 percent, in whatever was billed as a demand rate?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And we went through this morning, some schedules that in Tab 15 of the Book of Documents, that showed what would be the impacts of the 50 percent, the sixty-five (65) and the 100 percent inclusion of demand costs for various customers?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: All right. And the second change that you asked the Board to implement back in the 2003/'04 General Rate Application, was to change the billing determinant of the demand costs to be based on actual demand, as opposed to the average demand methodology that had been used in the many years prior to last year?

MS. KELLY DERKSEN: Yes, that's true.

MR. BOB PETERS: And the primary reason for making that request of the Board, Ms. Derksen, is you were in a position to tell the Board that you had the necessary meters installed, and you could now measure with some accuracy what the demand costs were by each of the customers in the high volume firm?

MS. KELLY DERKSEN: We could certainly measure their -- their peak day requirements, which would then allow us to bill appropriately, the demand charge.

MR. BOB PETERS: Once you knew the peak day levels of each of your customers, you could then decide who bore what -- what amount of the costs that that class had to pay?

MS. KELLY DERKSEN: This is not an issue of cost allocation, so I'm not sure if that's what your question was implying, but it's not an issue of allocating the costs -- the demand costs to the -- to the customer classes, but certainly determines which customers will pay for the hundred dollars ($100) of revenue requirement that you need to collect on account of demand costs from that class.

(BRIEF PAUSE)

MR. BOB PETERS: And in terms of the recent history, PUB Order 118/03 that you referenced earlier, Ms. Derksen, it did in fact change the percent of demand costs recovered in the demand rate from fifty (50) to 65 percent, correct?

MS. KELLY DERKSEN: Correct.

MR. BOB PETERS: And I've actually forgotten your answer, I thought you may have addressed this, this morning, but is it the Corporation's intention to move from 65 percent to a higher percentage or maybe ultimately to a

100 percent?

MS. KELLY DERKSEN: I don't think we've concluded on that yet. I mean we certainly need to look at the -- at the issue and make those determinations and if we have -- if we determine that 65 percent is not the appropriate amount, then we would bring forward a proposal to the Public Utilities Board at some subsequent general rate application.

MR. BOB PETERS: Is it because there will be cross-subsidization between customers in the class, that leads you to have concerns about whether the amount of demand costs recovered can be 65 percent or some other number, Ms. Derksen?

(BRIEF PAUSE)

MS. KELLY DERKSEN: I think one (1) of the -- the primary issues for -- for the Corporation with respect to moving off the 65 percent recovery of demand costs in -- in the demand rate is with respect to the interruptible class, we have a number of customers in that class who are seasonal, and would not bear any responsibility for demand costs. So we'd certainly have to look into that issue.

We'd have to also concern ourselves with the high volume firm class, and if it's appropriate to move off to -- off the 65 percent customer acceptability and understandability, obviously being an issue for us, particularly in -- in light of, you know, what's occurred in the last year.

MR. BOB PETERS: Do you -- does the Corporation, Ms. Derksen, feel they have to treat the high volume firm and the interruptible customer class in lock step, or could you treat them as different issues?

MS. KELLY DERKSEN: I certainly see them as different issues, but -- and they would be looked at, at the same time, so we would be making a proposal of how to deal with both of the matters, likely at the same time.

MR. BOB PETERS: All right. And just so we're clear and we don't have to debate this on the record, Ms. Derksen, but in the -- in the Board's Order 118 of '03, there was approval for some change in methodology for calculating the -- the billing determinants for the demand component of the rates. And there was some issue as to the timing as to when that change in methodology was to be implemented. Do you agree with that?

MS. KELLY DERKSEN: I think we received approval for a couple of things, that being one (1) of them is the approval to -- to bill, based on actual peak day.

The second approval that of course that we received is approval of the rate that needs to exactly coincide with the type of methodology that you're employing. So, we saw that we received a couple of approvals on account of this issue.

MR. BOB PETERS: All right. And I'm not debating with you as I promised I wouldn't. Ultimately there was a -- an Order 16 of '04 issued, perhaps by this Panel, if I recall and Centra was then to delay the implementation of the methodology change and that was going to be addressed at this proceeding that we're at today?

MS. KELLY DERKSEN: I would say that we were to discontinue billing on a basis of action peak day in light of the confusion and perhaps misunderstanding surrounding this issue and the implem -- the re-implementation of this issue would occur once that we discussed it in this forum, at some later period.

MR. BOB PETERS: All right. And when that occurred, Centra revised its rates and was asked to recalculate the impacts and to bring those things forward for this Hearing?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: In that Order 45 of '04, which actually approved the new rates, Ms. Derksen, I believe there was a request from the Board that your customers in the high volume firm class be notified of this being an issue that would be coming forward in this cost of gas hearing. Do you recall that, as well?

MS. KELLY DERKSEN: Yes, sir, I do.

MR. BOB PETERS: Can you tell the Board what you did to notify your customers that this issue was coming forward, that is those customers in the high volume firm class?

MS. KELLY DERKSEN: There were a number of pieces of communication that we have had with the customers in the high volume firm class since that -- the issuing of that order. First, we sent out a newsletter, I believe in April of 2004 advising of the move back to average peak day.

Subsequent to that time, we and I personally have met with several high volume firm customers to discuss this issue. We also sent out a letter to each individual customer, I think that was sent out at the beginning of August of 2004, that stated what the issue was and what the impact of this issue would be on their particular business.

So, there's been a number of sources of communication about this issue since that time.

MR. DARREN RAINKIE: I would add, Mr. Peters, that this was in the initial public notice for this Application. And I think it was -- it was published in the newspaper in March of 2004 and in the reminder notice that was published in August of 2004.

And in connection with the Board's

instructions, when we sent out the -- the customer communication on the initial Application also a notice and a timetable was attached to that communication, as well.

That of course is also supplemented by our marketing reps being out there and discussing any issues that our customers have on an ongoing basis.

MR. BOB PETERS: Were your marketing representatives instructed to speak to each of the approximate eighty-one (81) customers Mr. Rainkie, on this specific issue?

MR. DARREN RAINKIE: I'm not sure that they went and addressed that issue specifically. But, they would be out there with the customers after these various communications had -- had been sent out.

And of course, they'd be willing to engage in any issue that the customer wanted to chat about.

MR. BOB PETERS: In terms of the reasons you give your customers for wanting to make this change, is the minimization of the cross subsidization the largest issue, or the largest reason?

(BRIEF PAUSE)

MS. KELLY DERKSEN: I think that's one of the issues. I think the -- there are several issues as to why this is more appropriate -- a more appropriate billing methodology, which we would cite to the customer.

In addition, there would be, you know, the fact that we want to bill consistent with how the costs that we incur. We want to bill them in the same fashion and of course, that would tend to minimize the cross subsid -- cross subsidization. And so I think there's a couple of issues that are important when we move to this type of -- of billing methodology.

MR. BOB PETERS: Well, for a specific customer -- that is -- I mean one of your reasons for wanting to go to this new billing methodology would be to give customers a better signal as to how to manage their -- their load factor perhaps; would you agree with that?

MS. KELLY DERKSEN: Yes, I would agree.

MR. BOB PETERS: Do you also accept that there may be customers on your system that are, for various business reasons, unable to change their load pattern?

MS. KELLY DERKSEN: I agree with that. I don't mean to sound insensitive. You know, obviously there's going to be individual circumstances that would prohibit a particular customer from doing that.

But, one of the benefits from -- from our perspective is that there at least is that possibility because it gives you a signal as to what types of costs that you’re -- that you’re causing on this system, so it gives you a better indication of that type of information.

MR. BOB PETERS: Mr. Rainkie, do you know if your marketing representatives go to these eighty-one (81) customers and ask them -- meet with them and specifically give them ideas as to how they could maximize their -- their load factor?

MR. DARREN RAINKIE: I would say yes, and I would note, I think in the letter that we sent out in August, I think it -- it ended by saying, if you would like to discuss those types of opportunities, give us a -- here’s a number that you can call.

I don’t know -- I can’t remember if it was the marketings reps individual number or a general number, but the number was there, irregardless.

MR. BOB PETERS: In turning to the financial impacts of this proposal that you have before the Board, it is correct for the Board to conclude that this is revenue neutral in respect of Centra Gas Manitoba Inc.; s that correct?

MS. KELLY DERKSEN: With respect to the implementation of -- of moving from average peak day billing to actual peak day billing, it is revenue neutral for Centra, yes.

(BRIEF PAUSE)

MR. BOB PETERS: And would you also agree that it is revenue neutral with respect to the high volume firm class itself? That is, you're not recovering any more or any less than you would otherwise, it's just a different way to recover it?

MS. KELLY DERKSEN: Yes. I made the statement that I specifically did because it's a different situation once you start considering what I've called the back billing piece of it, so that's why I specifically made the response that I did.

MR. BOB PETERS: We'll come to that and give you another chance at that, Ms. Derksen, but before we do, I'd like you to turn to Tab 17 of the Book of Documents that I circulated and, in Tab 17 there is a photocopy of a document entitled "Tab 7, Attachment 3, June 23 of '04".

That would be a document that you're familiar with, Ms. Derksen?

MS. KELLY DERKSEN: Oh yes.

MR. BOB PETERS: And this document is to show the Board the impact on eighty-one (81) unidentified customers of the two (2) different billing methodologies, correct?

MS. KELLY DERKSEN: Correct.

MR. BOB PETERS: And I scanned it, before I turned the microphone on, and I thought Customer Number 3 and Customer Number 18 represented the -- the book ends, if you would, as to which ones had the -- the greatest impact, either positive or negative. Have I missed one?

(BRIEF PAUSE)

MR. DARREN RAINKIE: Mr. -- Mr. Peters, are you operating your calculator on dollars or percentage?

MR. BOB PETERS: Lawyers always use dollars, Mr. Rainkie. Accountants may use a different number. But you're telling me that there's a different percentage impact and that's possible as a result of specific customer information?

MR. DARREN RAINKIE: Everything's relative to your total bill I guess, yes.

(BRIEF PAUSE)

MR. BOB PETERS: Is it your preference, Mr. Rainkie, that we -- that we look at the absolute percentage amount, maybe down to Customer Number 67 as a -- a better proxy for the one that would have the highest increase as a result of the change in methodology.

MR. DARREN RAINKIE: I think generally, yes, we're looking at percentage changes because if you don't divide that by your total bill I think you can -- you can make some misleading interpretations if you just look at the raw -- raw dollars. That's only my perspective.

MR. BOB PETERS: All right. So, what -- what this schedule, then, is showing the Board is that if the -- if the decision to go to actual peak is made and moving off of actual peak for at least the customers who are impacted on a percentage basis as shown in the last column on Tab 7, Attachment 3.

MS. KELLY DERKSEN: I think the -- the response to the question is yes, recognizing that this isolates just the impact of this change. So, to the extent that we have made other proposals in this Application on account of changes in gas costs, that would be incremental to the amount shown on these particular -- on this particular -- this particular schedule.

MR. BOB PETERS: Okay, I just need to understand your last answer to me, Ms. Derksen. If I look at your Schedule 8.1.0 revised, and I included a copy of that schedule under Tab 15 of my Book of Documents, although I don't have, admittedly, the most current one (1), I want to turn to the high volume firm impacts.

And, Ms. Derksen, looking at the far right hand column under the high volume firm customer class, the numbers that are on the yellow sheet are now outdated and incorrect?

MS. KELLY DERKSEN: True.

MR. BOB PETERS: And you've updated those with your green sheet, but the range of impacts on your green sheets for the high volume firm customer is still between a -- a reduced annual bill between the range of 7.2 percent and 8.5 percent?

MS. KELLY DERKSEN: That's the range, yes.

MR. BOB PETERS: Now, does that reduction on the Schedule 8.1.0 take into account and embed in it, the results that you've shown the Board on Tab 7, Attachment 3, found in Tab 17 of the Book of Documents?

MS. KELLY DERKSEN: I'll have to explain a couple of things here, it recognized that Attachment 3 of Tab 7 that you have in your Book of Documents as Tab 17, that's a very individualized customer calculation, as a result of only the change in moving from average peak day to actual peak day.

The Schedule 8.1.0 is a representation of what we expect the class to be impacted by, as a result of all of the changes that are proposed in this Application.

What this Schedule does, 8.1.0, is it takes into consideration the rate change, but because average to actual is a very individual change, it does not contemplate the change in the demand units for a particular customer class, and really you need both of those things to recognize the total impact to an individual customer within that class.

MR. BOB PETERS: Would it be correct then to simply find the customer at the various load factor and volumes used in Schedule 8.1.0, and then look at the percentage change that would result from the change in methodology on Tab 7, Attachment 3, and -- and just do the math?

MS. KELLY DERKSEN: It's not that simple, Mr. Peters. First of all, there is -- there -- we use different information to calculate the average versus actual demand calculations on Attachment 3. We used information of the customer's actual peak and average peak consumption that was established between August the 1st of 2003 and July the 31st of 2004, as the basis of the calculations on Attachment 3.

What we would incorporate in Schedule 8.1.0, would be a forecast of what we expect each customer in that class to use on an actual peak day basis.

So, it's -- it's not going to be as simple as what you suggest.

MR. BOB PETERS: And would I also be correct, Ms. Derksen, that you haven't run, for the eighty-one (81) customers, a -- a calculation of what would be the bill impact as a result of your Application, if it was approved as filed, including the methodology change in determining the high volume firm demand rates?

MS. KELLY DERKSEN: Not an individualized calculation, no.

MR. BOB PETERS: In turning to the specific individual customer impacts -- and turning in Tab 17, Ms. Derksen, to the second document that's there, and that's a copy of your Tab 7, Attachment 4; is that correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And can you explain to the Board what you're trying to demonstrate on this Attachment?

MS. KELLY DERKSEN: Centra implemented actual peak day billing for all customers in the high volume firm class in November of 2003. Subsequent to that the Board issued an order to say stop billing on the basis of actual peak day, until we can iron out some of these issues.

And so what this demonstrates here is, had we not billed based on actual peak day billing effective November 1st of 2003 until February the 29th of 2004. This is what the customers would have actually paid different than what they got billed.

MR. BOB PETERS: Can you explain to the Board why, on a net basis, it doesn't zero out?

MS. KELLY DERKSEN: There's a couple of things happening on this schedule that -- that make things that make things a little bit complicated.

On August the 1st of 2003, our proposal to the Board was that we were going to implement actual peak day billing on November 1st of 2003. The rates that we created on August the 1st, 2003 that were ultimately approved by the Board incorporate both average demand billing and actual demand billing units.

So, it's what I call a blended rate. It incorporated some average units and some actual units. Average units to recognize the period when we would continue billing on an average peak day basis between August the 1st of 2003 and November the 1st of 2003 and actual peak day units to reflect the fact that we would then move to bill on an actual peak day basis on November the 1st.

Remember -- remembering always that two (2) things need to happen for this change to work properly; first your rate needs to change to reflect what you're billing and the second thing that has to happen is that your customers will need to be billed on either an average of the peak month or an actual peak day basis.

So, the rate that we struck on August the 1st of 2003 was a blending of those two concepts because we were implementing it not until November the 1st of 2003. In addition, because we had a blended -- a blended rate we --

there would have been a difference between -- the other -- the reason why the eighty five thousand dollars ($85,000) occurs is primarily because we had a blended rate in place that wasn't a pure rate that wasn't purely average or purely actual and also on the account of weather.

Weather will cause you to deviate. Your rate will be different or how you create your rate will be different than what your billing customers on the basis of, on account of weather.

MR. BOB PETERS: Thank you for that explanation. So, just so the Board then understands this Tab 7, Attachment 7, found at Tab 17 in the Book of Documents that have been prepared for Board Counsel, had the Corporation not changed its billing methodology last August 1st, the customer would have been either better off or paid more as shown in your schedule?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: So, just to take Customer Number 1 as an example, by changing the billing methodology last August 1st, compared to leaving it where it would have been, this customer has paid five hundred and sixty dollars and sixty cents ($560.60) more under the -- under the new methodology that you used then under the previous existing methodology.

(BRIEF PAUSE)

MS. KELLY DERKSEN: Yes, that's correct.

(BRIEF PAUSE)

MR. BOB PETERS: I might have to think with my accounting hat on here, Mr. Rainkie. The five hundred and sixty dollars ($560) from Customer Number 1 would be an amount that would have to be owed to the Utility as a result of the change in methodology; would you agree with that, Ms. Derksen?

MS. KELLY DERKSEN: Yes, that's if we were to back bill the customer to say between August the 1st of 2003 and February the 29th of 2004, because Centra employed a different methodology in terms of billing peak day than what the Board had in mind, this is how much the -- this particular customer, Customer Number 1, would receive in a bill from Centra if we were to implement this piece of the issue.

MR. BOB PETERS: And just the converse of that, then, is that those customers who have a number that's shown in brackets, that would be amount that would have to be refunded by the Utility to put them back in the same position as before the change was made on August 1st of '03?

MS. KELLY DERKSEN: Correct.

MR. BOB PETERS: And I heard you tell your Counsel, Ms. Murphy, this morning that you are asking the Board to not order a back billing or a back refund methodology; have I got that right?

MS. KELLY DERKSEN: That is Centra's position, yes.

MR. BOB PETERS: And as I understood your position, and in my notes, your suggestion is that there was seven (7) months in which the -- the billing irregular -- irregularity, if I may, occurred, and there have now been another seven (7) months or eight (8) months in which it's been reversed and by way of, perhaps, a high level analysis, the two (2) would wash out or equate and there would be no need to either go back to customers with a request for additional payment or a request -- with a cheque for a refund?

(BRIEF PAUSE)

MS. KELLY DERKSEN: I think that's true, Mr. Peters. I think that our position, at least in my mind as well, is that on August the 1st of 2003, Centra received a Board Order that said we agree with the methodology of moving to actual peak day billing for this class and we also agree with the rate and therefore we -- in our minds, we received approval to implement the change.

Subsequent to November 1st of 2004, we received direction from the Board that said, hold on a minute. There's some confusion surrounding this issue. Before we go any further with respect to this issue, let's revert back to average peak day billing. Bill -- and until we sort out these matters, let's continue billing on that basis until we can further review it at the upcoming gas cost application.

So, from those two (2) perspectives, we think that it's our position that the back billing piece do not occur.

MR. BOB PETERS: In my words, Ms. Derksen, the -- the high level balancing that you're proposing to the Board -- have you done any underlying analysis by a specific customer to see if that is roughly correct in terms of balancing out?

MS. KELLY DERKSEN: Yes, I have.

MR. BOB PETERS: For all of the customers within the class?

MS. KELLY DERKSEN: Yes, sir, I have.

MR. BOB PETERS: Would you be prepared to file that analysis so the Board could -- could just see what underpins your recommendation, as an undertaking?

--- UNDERTAKING NO. 12: Ms. Derksen to file analysis customers of actual and average peak day billing.

CONTINUED BY MR. BOB PETERS:

MS. KELLY DERKSEN: The information is compiled. I'd just have to look at -- look at it further before it could be submitted so it could be submitted to the -- as an undertaking. However, it may be a couple of days before that -- that information would be filed.

MR. BOB PETERS: That would be fine, Ms. Derksen.

Last question in this area, is: Does anything turn on there being eighty-one (81) customers on Attachment 3 and ninety-three (93) customers on Attachment 4?

MS. KELLY DERKSEN: Nothing turns on it, Mr. Peters. We had some movement of customers, either into the high volume firm class or out of the high volume firm class, effective November 1st of 2003 and that's the difference that you're seeing.

The -- the one (1) calculation is a prospective looking calculation that says, if we institute or implement this change, here's what we expect customers to be impacted by, so we're only really looking at the customers that currently reside in the high volume firm class.

MR. BOB PETERS: When I said that was my last question, I was just kidding but -- at least in this area. Ms. Derksen, are all of these customers system supplied customers or would any of these be under direct purchase?

MS. KELLY DERKSEN: We have a combination of customers in this class. We have some WTS customers, we have some transportation service only customers and we have some sales customers.

MR. BOB PETERS: Mr. Chairman, I'm going to move on to my final area of terms and conditions with this Panel, and this might be an appropriate time for the afternoon break?

THE CHAIRPERSON: Okay, let's say 3:10.

--- Upon recessing at 2:54 p.m.
--- Upon resuming at 3:12 p.m.

THE CHAIRPERSON: I guess there's no risk of you being dehydrated, Mr. Barnlund.

Well, in an effort to enliven the Proceedings and not to say that Mr. Peters is putting us all to sleep, we're -- we're going to switch to Mr. Carroll. Mr. Carroll, do you want to begin your cross-examination? We'll come back to Mr. Peters later.

MR. BILL CARROLL: Thank you, Mr. Chairman.

Thank you, Mr. Peters, for those questions. I have some questions along the same lines.

I guess I'd like to start by saying that many of the people in this room have sort of made gas hearings their life work. I know the people at that table have made gas hearings their lives' work, especially these rate applications that seem to take on a life of their own.

That's not the case for -- for me or for MacDon Industries, we've only recently become students of utility -- gas utility rates, over the past few months. So, bear with me if some of our questions seem a little dopey, but we're just trying to understand what's going on here. We're still going up the learning curve.

We kind of feel like the biblical David sitting here, I must say, and after Mr. Peters' questions this morning and this afternoon, I'm not sure that I'm not more confused, rather than less confused.

We take our hats off, both Mr. MacDonald and I, to the Board, who last month listened to Hydro rates and this month listened to gas rates and next month listen to license plate rates. So how you take it all in is somewhat beyond us.

CROSS-EXAMINATION BY MR. BILL CARROLL:

MR. BILL CARROLL: In any event, I have a list of questions that we prepared ahead of time.

The first few questions are sort of policy oriented questions, and perhaps Mr. Warden might be the person to address those and then I'm going to get into some of the rate issues, as we understand them and -- and the expert members on the Panel could probably help us with those.

This morning, Ms. Derksen, used the term, "understandable" a couple of times. And it's odd because that's in my first question. And my first question is, do you believe that these hearings would be understandable for the average customer?

MR. VINCE WARDEN: This testimony by this Panel has been so smooth, up until now, that I hate to interrupt that flow. But, Mr. Carroll, it is a very complex area, there's no question.

We tried our very best to make it as understandable, excuse me, as we can. We have numerous bill inserts and energy documents that go out to our customers. We have representatives that visit with out customers, try to explain as best we can, the issues that are -- are effecting their bills.

Having said all that, it is a complex business. And Manitoba Hydro having acquired Centra Gas back in 1999, I think I'm just catching on myself to the business.

And it takes some time, there's no question. But we do our best.

MR. BILL CARROLL: MacDon Industries isn't my only high volume firm customer. I have several other ones. And my next question is, do you believe that the average high volume firm customer understands the recent changes to the demand rate, those being the shift from fifty (50) to 65 percent in cost allocation and the move from average day peak month to peak day and the whole cost allocation process?

MS. MARLA MURPHY: Mr. Chairman, perhaps we could give Mr. Carroll some direction in terms of the line of questioning that this panel is able to answer. Certainly, Ms. Derksen has spoken to the kind of steps that have been taken to inform customers.

But we aren't in a position to speak to what customers may or may not understand.

MR. BILL CARROLL: In response to some of Mr. Peters questions earlier, on residential customers, the Utility in fact, argued that the understandability of what -- of what the residential customers knew was an important element in some of the rate making decisions. So I would argue my question is valid.

THE CHAIRPERSON: I think Mr. Warden is volunteering over here.

(BRIEF PAUSE)

MS. MARLA MURPHY: Maybe he wasn't really volunteering.

(BRIEF PAUSE)

THE CHAIRPERSON: Mr. Warden? Ms. Derksen?

MS. KELLY DERKSEN: I was going to answer it from -- your question from the prospective of the information that I have received to date.

Through the numerous communications that have gone out, thus far with respect to the change in the way that we bill demand for high volume from customers, those being energy market comments. I personally met with several high volume firm customers to -- to help them understand or to see what kinds of questions or concerns they had over this change.

We have sent out letters at the -- at the beginning of August with respect to this issue. And out of all of the communication that we have sent and probably going back the seven (7) years since this issue really surfaced, we have to date received four (4) customer responses on this issue. Providing us information as to the concerns, their concerns about the change in moving to actual peak day billing for high volume firm customers.

Two (2) of those concerns were concerns that we were flip flopping as what they termed it to be between -- moving from average peak day to actual -- to average peak day to actual peak day.

So, four (4) questions or concerns out of all the communications that we have sent out on this issue from our perspective, does not signify a significant misunderstanding or misinterpretation, or however that you want to call it, with respect to this issue.

CONTINUED BY MR. BILL CARROLL:

MR. BILL CARROLL: Thank you. Given that about half of the high volume firm customers are going to see cost increases, some of them are -- are quite substantial.

And given that MacDon Industries is the only industry that's chosen to show up for these Hearings, do you think it's possible that the process has become so complex, that the average industrial customer has sort of given up in trying to understand or be able to change the direction that the Utility has taken?

MR. VINCE WARDEN: Mr. Carroll, you know, I really don't think the -- the fundamentals of what we're doing here are all that complex, some of the mechanics of how we get there -- sometimes can be quite complicated. But we have, you know, an energy rate, a demand rate, I think most customers understand that.

And what we're advocating with this change is one (1) of fairness, we're allocating our costs to a customer class, and we want the customers within that class to pay their fair share, it's a simple as that. And that's what we're achieving with this change.

MR. BILL CARROLL: I sat here last week and I listened to the Utility and to Direct Energy talk about hedging and hedging strategies, and actually it was fascinating, I found it very interesting.

And I was wondering if the Utility has ever considered taking a -- a cooperative approach and going out to their large customer base with somebody like Direct Energy or somebody else, and actually doing a workshop on hedging. As much -- as much as we found Goldilocks and the two (2) bears interesting, perhaps that would be a better way to get information in the hands of people that really need it?

(BRIEF PAUSE)

MR. BRENT SANDERSON: Maybe I can add something that may be of use to you. I am aware of the fact that our direct -- our broker relations representative in gas supply pricing administration which -- who acts as an intermediary between the Utility and the broker community in Manitoba, has on a number of occasions gone out to customer's premises at their request, with representatives of the broker community to discuss these issues.

I can't give you quantification of how many times that's taken place, but I am aware of a number of occasions where that has taken place.

MS. KELLY DERKSEN: And if I could add, Mr. Carroll, please. I had met with a group of high volume firm and interruptible customers in -- sometime in June, just this past June. And the results or the indications from the customers that we met with at that time, I met in conjunction with our marketing folks, that our session, which dealt with you know, this high volume firm issue, and helping customers understand the changes that were proposed to take -- take place.

In addition there were other issues of interest or at least what we think are of interest to customers that were provided to customers at that time. And the reception from all of the customers there, there -- there may have been a dozen or so customers attend, was very positive.

And as a result of that session we had with that particular group of customers, I know that our marketing people are planning on doing those types of communications with customers on a much more frequent basis, and include topics like those that you discussed, related to hedging.

MR. VINCE WARDEN: I also might add before we conclude, if I may, that I personally have spoken with representatives of major industrial customer organizations on subjects specific to hedging and price management and so forth, and rate setting at the request of our key and major account reps.

When the discussion -- when the customer is desirous of a discussion, it gets maybe more technical than the rep's background would allow, it's not unusual for them to contact me and I will either contact the representative of the customer's firm. Or the customer will contact me directly and we will have these discussions at their request and convenience.

MR. BILL CARROLL: Thank you. That's kind of where I was heading with this. I know that Natural Resources Canada puts on workshops for energy management and Environment Canada puts on NPRI workshops. and I've attended at those with -- with other users and I think that what you're proposing now or planning on doing is an -- is an excellent idea.

My next question is: does the Utility care how natural gas is used after it passes through the meter, which is sort of your cash register? And do you believe that there's a difference between gas used for space heat and gas used for -- as a production input?

(BRIEF PAUSE)

MR. VINCE WARDEN: Well, the Utility certainly cares how that gas is used and -- and that's what our demand side management programs are all about, is to ensure to the extent possible that energy in total is being used as efficiently as possible.

So, our interest doesn't stop at the meter.

MR. BILL CARROLL: And what about the use of gas for space heat, versus the use of gas for a production input? Does the Utility see any difference there, or is it just gas use?

MR. VINCE WARDEN: Well, I think we have to look beyond that general statement and gas that's being used in production facilities -- we have to delve into just exactly what process it's being used for.

I know that our -- our representatives, our customer service representatives are -- go out and visit with customers and -- and do their best to understand their processes and advise them as to the most efficient use of -- of the product they're using, both gas and electricity.

MR. BILL CARROLL: The utility has a policy of 1 metre per service address and we think that maybe that penalizes customers with use patterns like MacDon’s. We’re not sure, because we haven’t done the analysis and we need help doing that analysis.

Would the Utility be prepared to change that policy, or at least be willing to look at the policy?

(BRIEF PAUSE)

MR. VINCE WARDEN: You’re probably getting a little bit beyond the expertise of this Panel, Mr. Carroll, though I am aware that there are a number of customers that have multiple service points.

So, if you’re interested in pursuing that, we could perhaps have a representative contact MacDon.

MR. BILL CARROLL: I know that when we did the addition, that Mr. MacDonald spoke about this morning, I was actually the project manager for that addition. And we tried to get two (2) service meters, because we knew that that addition was going to be a huge consumer of gas and it wasn’t allowed, so, that’s how I know what your policy is.

If I could refer you to Exhibit 3 in the document that we filed this morning, or that Mr. Peters asked that be filed this morning. It’s a graph that Hydro supplied us of the MacDon Industries gas use.

And I think -- if you have that in front of you.

MR. VINCE WARDEN: Yes, we have it here.

MR. BILL CARROLL: I think you can sort of see what's going on there, during the five (5) days a week that -- that -- that this company uses or does production. There's a huge peak in the middle and that's the gas that's the production input.

Saturday and Sunday -- Saturday's a little higher than Sunday, because sometimes there's some work done in the plant on Saturdays and Sundays, but that's sort of the space heed load.

This is -- this is a load pattern that's not easily changed. And we thought that if we could use different metering for the space heat versus production heat, we -- we could save some money, perhaps, because the demand charges are being imposed on top of the space heat charges.

And so we don't know how that works, but we think that possibly the Utility could help us out in that.

(BRIEF PAUSE)

MR. VINCE WARDEN: Mr. Carroll, I -- I really think it would take in depth analysis of your operation to determine whether or not it's to your advantage. Remember if you had two (2) meters, you'd be subject to two (2) monthly basic charges, and other costs that might go along with it.

And remember, it's not changing the cost profile of Centra, we still have ex -- a fixed amount of costs that we have to recover from our customer base. So, it -- it becomes -- it could become a fairness issue as well, is it fair to other customers to install one (1) meter for heating and another one (1) for production, without offering that same advantage, if -- if it turned out to be to all customers.

And if it was advantageous on an individual customer basis, we'd still be dealing with the same costs in totality, which we would have to allocate to -- to our customer base. And if every customer opted to separate their heating and their production loads, it seems to me there would be incremental costs that would have to be recovered from those same customers.

So, I think it's something that would require more in depth analysis than what we -- we can provide, in this Panel today.

MR. BILL CARROLL: Thank you, I -- I guess I'm just poking at the issue about how flexible the Utility is in terms of helping this particular client that I'm representing today.

On that same Exhibit 3, it's not hard to visualize how if this company ran an extra shift, on a cold day in February, they would pay for it for the rest of the year. And that's one (1) of the key issues that -- that there is for MacDon Industries, is that now they can't run a double shift, because if they run a double shift, that curve doesn't start coming down at sixteen hundred (1600) hours, that curve goes on, and if you do that on a cold day, suddenly you've incurred a whole lot of costs for a whole year, and that's one (1) of the reasons they're so sensitive to this issue.

MR. VINCE WARDEN: That's true, but it's -- you know, that's a business reality, and I guess it's a business -- a decision that MacDon would have to make, as does every other customer that's faced with that -- with that issue.

MR. BILL CARROLL: I'd like to ask some questions now on Tab 14, in Mr. Peters' Book of Documents, which is Schedule 7.1.0.

(BRIEF PAUSE)

MR. BILL CARROLL: I thought I had a grip on this schedule until Mr. Peters started asking questions today.

I heard the explanation on line 14, in terms of the supplementary firm and supplementary interruptible, and as I understand it, those are the demand related costs that go along with supplementary gas; is that correct?

MS. KELLY DERKSEN: No, there's a little bit of confusion there I think. The costs that you see on line 14, up until the time that you -- you end our traditional customer classes, which would end at the power stations, those are a combination of both demand or fixed capacity costs that we cur -- incur, both upstream in our system, and within our own system, as well as some variable commodity charges like unaccounted for gas costs that we incur on our system to provide a service.

The amounts on line 14 are each class's allocation of those types of costs. The supplemental gas charge that you see at the end of that row for both firm and interruptible customers, is a completely different charge that appears on all sales and WTS customers' bills, for the supply of natural gas that typically comes from -- from the United States.

So, basically at the end of the day, what the high volume firm class will pay is a contribution toward the $4.5 million that you see on line 14, as well as a contribution toward the $17 million number that you see under the supplemental firm column.

So, mapped on -- no different than any other high volume firm class, would be subject to -- would be responsible for both of those types of costs.

MR. BILL CARROLL: Thank you. I think I understand that part. Those two (2) numbers under the supplemental firm and -- and interruptible are about 20 percent of the -- of the 83.4 million.

And as I understand it, the -- the split in firm supplemental gas is ninety-six four (96.4) or one hundred zero (100.0) or slightly different than that in interruptible. The 20 percent to me seems out of line with the split in the other volumes. Can you rationalize that for me?

MS. KELLY DERKSEN: Yes, I'll clarify that for you as well, Mr. Carroll. The billing percentages that we discussed this morning that generally are, say 96 percent primary and 4 percent supplemental, that represents the portion of primary gas that a customer -- a firm customer would pay versus the portion of supplemental gas, say the 4 percent that a customer would pay.

So, on every -- every firm customer's bill what they would see is primary gas at a rate times 96 percent because we supply those types of customers with both -- with a mixture of both primary gas and supplemental gas.

The primary gas is our primary source of supply and hence the name, which comes from Alberta and that represents approximately 96 percent of the total gas requirement or gas supply that a customer pays.

The 20 percent that you're speaking of, which is the difference between the firm and the interruptible, really has to do with how we supply supplemental gas between firm and interruptible customers. And no firm customer would pay for the two point six (2.6) or the $2.7 million that's under the column called supplemental interruptible. That would solely be charted to the interruptible class.

MR. BILL CARROLL: I guess the part that I can't get my mind around is, the -- the large fixed cost here versus the small amount of volume.

(BRIEF PAUSE)

MS. KELLY DERKSEN: I'm -- I guess I'm a little bit confused by it -- by your question, the supplemental gas that you see under the supplemental firm and the supplemental interrupt -- interruptible columns, those are not fixed costs, like we were talking about the demand component on the bill, those are variable charges.

So, we go out and we purchase gas supplies from both Alberta, and in this case, from -- from US sources. And we pay for every volume of gas that we purchase on behalf of the customer.

And we then charge the customer for every unit of gas that they use. So, it’s a variable cost. The fixed costs that we were speaking of earlier today, with respect to demand would be for the high volume firm class, for example, would be on line 4, under the high volume firm class or three point five (3.5) or 3.6 million, let’s say.

And in addition, there’s another thirteen and a half thousand dollars ($13,500) that would be a fixed demand related gas cost, as part of this Application. So that’s what we’re discussing when we’re talking about recovering the fixed demand costs on the basis of actual peak day or average peak day or whatever the methodology is that we’re speaking of.

MR. BILL CARROLL: Okay. So the seventeen point zero (17.0) and the two point six seven (2.67), don’t figure into the demand costs?

MS. KELLY DERKSEN: They do not, no.

MR. BILL CARROLL: Okay. That leads me to my next question then. The total amount of demand costs shown in this table, I think adds up to about 51.1 million when you don’t include those -- those commodity charges you were just talking about.

MS. KELLY DERKSEN: You’re very close, yes, Mr. Carroll.

MR. BILL CARROLL: And the demand costs for the SGS and the LGS total about $44.6 million.

MS. KELLY DERKSEN: That -- that's about correct, keeping in mind, Mr. Carroll, that what we're discussing on this particular table here is only gas cost related. So that would be demand costs that we incur on TCPL and on, say, the ANR pipeline in the United States.

And in addition, we have one (1) small pipeline, I think, in western Manitoba, called Monell pipeline. Those are the demand costs that would be incorporated in the schedule.

There are additional demand costs that are in the demand rates that -- that all customers would ultimately pay. Those demand costs are the demand costs that customers pay on account of Centra's system. And we have not included those in this particular table because this Application only deals with the gas cost portion or changes with respect to gas cost portions of, say, the demand rate and the supplemental charge that we previously spoke of as well.

So this is only part of the picture.

MR. BILL CARROLL: Thank you. I think I understand that. I think it's a -- it's a big chunk of the picture, though. And I guess the -- the one (1) issue that I wanted to point out was that 87.3 percent of the demand costs of this part of the picture, aren't recovered from customers through demand charges.

MS. KELLY DERKSEN: I guess I have a couple of points to make with you, if -- if you don't mind, Mr. Carroll, and that is I -- and it's my opinion that the demand cost component of a customer's bill is relatively small, certainly in comparison to the gas cost portion of a customer's bill.

If you accumulate the primary gas component as well as the supplemental gas component that is charged to a customer on a variable charge -- on a variable basis, it's -- it's my belief or based on -- on what I know today, that that represents a much greater portion of a total customer's -- of a total bill for a customer than the demand component.

For example, a typical residential customer and I'm sure to whom we all can relate, if you are to consume thirty-two hundred (3,200) cubic metres of gas a year, which is an average customer, 60 percent of your bill is primary gas and supplemental gas.

And so that is a much greater portion than the demand cost. In fact, I -- if I recall correctly, of all of our non-gas cost components, I think demand costs represent maybe a third of the costs.

So -- in total of a customer's bill I think the primary and the supplement gas components represent a much larger component.

MR. BILL CARROLL: You're talking about the commodity part of the bill, correct?

MS. KELLY DERKSEN: I'm talking about the commodity part of the bill. With respect to your second question, which was, you know, why are the smaller volume customers recovering -- why are we recovering their demand costs in a variable way and we don't treat the other, larger volume customers in the same way.

And, as we discussed this morning, one (1) of the primary reasons that we don't have a demand rate per se, although we recover those costs from the SGS and LGS classes is that, well, for one (1) it would be very expensive to put demand metering for two hundred and fifty thousand (250,000) customers on the bill.

And, in addition, like we've discussed as well, that I think the complexity of a demand billing for a residential customer may be fairly complex. And I think that's another good reason why we would not want to have a three (3) part rate structure for that type of customer.

MR. BILL CARROLL: I would argue that -- that the way that you do it for high volume firm customers, is also complex and hard to understand. And would the bottom line be that you charge high volume firm and interruptible customers demand charges, is because you can, because you have the metering in place? Whereas you can't with these other ones?

MS. KELLY DERKSEN: First of all, we put the metering in place for the larger volume customers because that we had intended to go to a three (3) part rate design. And I'm not -- I don't agree with your statement that we can do it and so we do.

I think from a cost allocation and rate design perspective the most equitable and fair treatment is a three (3) part rate structure because that minimizes the -- cross subsidy that would otherwise occur, as it does under the two (2) part rate.

So -- and I think that we have a different type of mind-set in some of the smaller volume customers that we just could not employ such -- such a type of charge because of the complexity of it.

MR. BILL CARROLL: I had some more questions along that line, but I think I'll leave them and move onto something else.

Are there options from going to peak day or is it the only possible alternative within the universe of options?

MS. KELLY DERKSEN: I'm aware of a couple of different methodologies that could be employed. I'm -- I'm certain that there are a number of different methodologies that are employed in other jurisdictions.

Other jurisdictions would be a little bit different than Centra because of -- particularly the type of climate that we have in this province, it's unlike most other provinces, certainly in Canada.

The other methodology that we could employ that would be reasonably cost based would be to bill on the basis of -- of a design day. And that would be to recognize all of the consumption in the high volume firm class and other classes on the basis of when -- when customers use the most amount of gas basically in history.

And I think that probably was in January of 1996 and we could recover costs in that way. And that provides a direct link then between how that Centra incurs costs because from a theoretical point of view, we have to put a pipe in the ground to be able to serve customer -- serve customers. No matter how cold it is outside, we have to put that pipe in the ground and we incur that fixed cost.

So, it would -- there would be a direct cost causal link between that recovery mechanism and the billing of it. But through the 1997 or 1996 cost allocation and rate design review, we discounted that particular methodology because a customer has no way then to control it.

They -- they can't observe it, they don't know what they've caused on the system. And although more theoretically correct, based on a design day, there were -- there were other considerations that took precedent. And that’s why we opted toward billing based on an actual peak day methodology.

MR. BILL CARROLL: Earlier it was indicated that the Utility is trying to encourage high load factors and to change customers load profiles, if they -- if they can. But can you understand and appreciate how the chosen option impacts a business like MacDon Industries and I understand, Mr. Warden’s comment that that’s the price of doing business, basically.

But are there options out there that could allow them to continue to do their business and grow their business and at the same time, recover the money that you guys require?

MS. KELLY DERKSEN: I don’t want to leave the impression, Mr. Carroll, that I sit in -- on my chair, at my desk, and just create you know, ways to recover -- to recover our money that -- that is completely unsympathetic toward a customer’s business operations. And in fact, I have conversations with the marketing people who are out there in contact with customers, to -- to better understand what their concerns and their needs are.

So with that preamble, I am sympathetic toward this type of situation. But keeping in mind that I also need to be sympathetic to the other seventy-nine (79) customers in that class, over 50 percent of whom would, you know, are --

are subsidizing customers like MacDon and have been for the last seven (7) years.

So I also have to be sympathetic toward those customers who compete in -- in similar circumstances to what MacDon does.

MR. BILL CARROLL: Thank you. Can you understand why my client is confused when the impact numbers that have -- that they've been given have changed so dramatically and apparently still continue to change?

At one (1) time, they were told the impact would be thirty-nine thousand dollars ($39,000). Then they were told the impact was going to be nine thousand dollars ($9,000). Now a new schedule's come out and we don't know what the impact of that's going to be, because I haven't calculated it yet.

And so, they're confused and they're upset because they keep seeing different numbers. Frankly, they don't believe the impact.

MS. KELLY DERKSEN: I am sorry for some of the -- you know, the information that has gone out and I can -- I can certainly why that there is confusion.

I can assure you that the calculations that we have done which provide the comparison between moving from average peak day to actual peak day are sound calculations.

It -- it is not as important to have the same rates in terms of the calculations that we did for that basis so long as you're doing two (2) things.

First is, that you're keeping all other issues constant, so there is no other impact as a result of any other change when doing the calculation.

The second important issue is that you have a consistency between how your rate is created and how you plan to bill for that rate. And so long as you have those three (3) things constant, you will pro -- you will come up with virtually the same information as what we have done.

And, in fact, when I reviewed the information that we filed with the Public Utilities Board, as part of the 03/04 General Rate Application, MacDon's impact as a result of solely this change was almost identical to what we had calculated back then, even though we used obviously a -- a different set of rates because we had, you know, different types of -- different levels of gas costs and so forth back then.

Unfortunately, the information that our marketing people provided to you that provided the thirty-nine thousand dollar ($39,000) impact, that was only one (1) side of the equation. And like I said, on a number of occasions today, that two (2) things have to happen.

You have to have a rate that reflects the type of billing that you are going -- that you are planning on doing, but you also have to change the demand units for a particular customer.

The calculations that were sent to you via our marketing department last fall only -- they assumed only one (1) part of that equation and you need two (2) parts of that -- that to occur.

And so that would way over estimate what the impact to the customer would ultimately be. And so from -- from that perspective, I understand that there's a number of numbers that have gone out there, but I can assure you that what we've provided provides a level of direction in terms of the impact to your business as a result of this particular change.

MR. BILL CARROLL: Thank you. When the information that Mr. Peters shows in Tab 17 came to MacDon, they asked me to look at and see if these numbers were right. This was the -- the ninety-six hundred dollar ($9,600) number and the forty-three hundred dollar ($4,300) number.

So I attempted to, with my little pea brain, figure out where these numbers came from and I asked you for some supplemental information which you provided in MACDON/CENTRA-12, on how the impact and rebate were calculated.

And I still remain slightly confused as the only rate in Attachment A and B, of MACDON/CENTRA-12 that I can find in any version of schedule 8.1.0, either the first version, the second version or the third version, is the zero point sis one seven (0.617) one, which is the sum of the two (2) demand rates.

That's the only number that's a consistent number. The rest of the numbers, I don't know where they came from. And I guess my question is, is this reasonable? Is this helpful for the customer?

MS. KELLY DERKSEN: At the outset, I'd like to say once again that the rates that you use to make these determinations so long as you have those three (3) constant factors that I discussed earlier, so long as you have those three (3) things included in your rates, you're going to ultimately come up with virtually the same results.

So, the -- the rates that I used in preparation of Attachment Number 3, as well as, sorry -- Attachment Number 3, what I did to come up with those rates is, I said, because I had to do an individual customer calculation as directed by the PUB, I needed information -- specific information from each customer as to their actual peak consumption and their average of the daily peak consumption.

So, we went into our SCADA system which provides us information as to -- on a daily basis of what each customer uses. And I was able to determine between

August the 1st of 2003, and July the 31st of 2004, what all customers in that class used, in terms of -- or set in terms of an actual peak versus an average peak.

And that then became the basis of my rate determination. That will vary from what's included in the Application that's before the Board today, because when we go to set rates, we set them on a forecast basis.

So we are forecasting what we expect each customer in that class to use, in terms of peak day consumption. So that obviously will be different than what they used last year.

And so the rates will vary. Once again though, that's not the bigger of the issues. As long as you have three (3) constant factors, those being that your rate is consistent with how you're billing and that you -- you ensure that no other change, no other gas cost change or non-gas cost change is occurring in your rate.

So long as those three (3) things happen, it's almost and I quote, the word, "almost", irrelevant which rate that you use.

I say, "almost", because we're also taking a percentage of this impact as a result of a total bill. And to the extent that rates increase and total bills increase that will slightly impact the result. But it's almost not worth mentioning, that's how small of an impact that would have.

MR. BILL CARROLL: Thank you. I’m going to ask you to turn to Exhibit 2, in the MacDon letter that was filed earlier.

(BRIEF PAUSE)

MR. BILL CARROLL: And again, it’s sort of my attempt at recreating what Centra had done in Schedule 8.1.0. And not necessarily understanding how you had arrived at 8.1.0, we tried to recreate it.

So, line 1 is the numbers right out of Schedule 8.1.0, the yellow version. And then line 2 is my attempt at recreating that number, and it’s fairly close, but it’s not exact.

Now, I’ve tried to recreate many of your numbers and come fairly close, but not exact, when I absolutely know how they’re calculated. So I assume that this is fairly -- fairly close.

And then I used that same methodology to calculate the impact on Mac -- MacDon, using the Centra method and then using the method that I thought was the right method.

The big difference is the way that the current billed rates is calculated. And it seems to me that what

Centra, and please correct me if I’m wrong, is that they used the peak day to calculate the current demand rate. That’s how I created that number of sixty-four thousand six hundred and eighty-two dollars ($64,682).

Am I right or am I wrong?

MS. KELLY DERKSEN: In preparation of this hearing, Mr. -- Mr. Carroll, I did go through your calculations to see if they were reasonable and I did conclude that what you have done is reasonable.

So you are right from that perspective. So I guess the question is: how is Centra’s rate -- how is Centra’s bill impact proposal for the high volume firm class so -- quite a bit different than the calculations that you have provided here.

First, with respect to lines 1 and 2, lines -- line 1 is what we have done. Line 2 is your re-creation of what we have done and other than, I -- I’ve disagreed a little bit with how that you calculated peak day information, but that’s really a red herring. We’re --we’re pretty -- we’re pretty much in the ballpark, so other than that particular issue, we could say that one (1) and two (2) are -- are pretty -- pretty close.

With respect to three (3), like I discussed with Mr. Peters this morning, what Schedule 8. -- 8.1.0 which outlines or provides a representation of what we expect the bill impacts to be resulting out of this Application. They do exactly what you say and that is, we have calculated those impacts using peak day with the current billed rates and peak day at the proposed billed rates.

On retrospect, I'm -- I may not have done the calculations the same way. But recognizing that, it is extremely difficult to pinpoint under Schedule 8.1.0 which is really trying to give you a representation of where the rates will -- what the bill impacts will be.

It's very difficult to figure out or to get an average change between a customer's average peak day usage and actual peak day usage, because obviously that's going to be very individual.

So for me to pull out a number out of the air and say this is representative of this class, probably wouldn't provide you with meaningful information.

So what I've concluded is that I have been able to derive your minus two point six (2.6) number that you have on line 3. And that, in my mind, would be what your individual impact would be as a result of this change. Except for one (1) thing and that is that we updated our rates on September the 2nd.

And if I do use that same calculation that you have done, I come up with a round -- a minus 4 percent, or a 4 percent decrease to McDon anticipated for November the 1st of 2004.

MR. BILL CARROLL: And do you agree that when you take the rate riders out, that something very different happens to those rates?

MS. KELLY DERKSEN: Sure that is, but you know, I'm not sure what -- why that is a big issue, because that -- that's monies entitled to the customer, and we're providing that -- that money back to the customer through rate riders.

So, you know, we're doing as what we -- what we said we're going to do and refund the money. So, the -- to the extent that customers are entitled to it, we've incorporated the amount that customer's bill -- that customer bills will decrease on account of refunding that money.

MR. BILL CARROLL: I understand and appreciate that, but I guess my client asked me, you know, compare sort of apples with apples, and don't include any of that other stuff. What's my -- what's the real impact that I'm going to see?

And so the last line that I show in here, line 6, is sort of the real impact that they're going to see when the rate riders come off. And I understand from the discussion this morning that many more things could happen between then and I'm with Mr. Peters, you know, what if, what if, what if.

But I guess in our view, the way that the impacts have been done leaves a false impression for the high volume firm customers. And I fully appreciate that you have no way of determining sort of what a typical before situation would look like.

I had to create that for MacDon just using, sort of, what I know about gas usage in -- in that company and other companies. So, for -- for the Board's information I think that the rate impacts show a better picture than there are.

My question is, after all of that, and it came out of a discussion earlier today, the rate riders are on for nine (9) months, I think?

MS. KELLY DERKSEN: Yes, that's -- that's our proposal.

MR. BILL CARROLL: And do the impact statements show twelve (12) month rates sort of nine (9) months with riders and three (3) months without riders, is that how they're calculated?

MS. KELLY DERKSEN: The way that the calculation is done, is that we take a typical residential customer, for example, who over a twelve (12) month period would consume thirty-two hundred (3,200) cubic meters of gas in a year.

We apply the current billed rates to that consumption level and then we would apply the proposed billed rates to that same consumption level. So that would tell us, over the course of the next twelve (12) months what we expect a customer's bill to change by.

MR. BILL CARROLL: Could you maybe re-state that, because I -- I still don't know whether or not, it's with rate riders for nine (9) months and not with rate riders for three (3) months, and then you get a total at the end.

MS. KELLY DERKSEN: The base component of the bill is calculated over a twelve (12) month period. The rider component of the bill is taking the nine (9) months that we expect to be refunding this money and the -- the nine (9) of volume levels and we've applied that nine (9) months in the calculation of bill impact.

So, we have twelve (12) months of base rate impacts and nine (9) months of rate rider impacts in those calculations.

MR. BILL CARROLL: Okay. Thank you.

THE CHAIRPERSON: Mr. Carroll, if I may ask, do you think you'll have much more because we can easily do it again tomorrow morning?

MR. BILL CARROLL: I have two (2) more questions.

THE CHAIRPERSON: Okay.

CONTINUED BY MR. BILL CARROLL:

MR. BILL CARROLL: My second last question is, I think your argument on not making refunds for past over billings or under billings, is that by delaying the increase until November 1st, 2004, users save costs that they would have owed, had the rate increase been put in sooner.

Is that essentially correct?

MS. KELLY DERKSEN: Our statement is, is that the move from actual back to average demand occurred on March the 1st of 2004, which is seven (7) months after that we implemented it.

And we were -- as the Board issued in Order 16/’04, direction to the -- to Centra, in our opinion, that we could begin billing on an actual peak day demand on April -- April the -- the 1st of 2004, which was set -- will be seven (7) months until the -- the new rates go into effect, on November the 1st of 2004.

So, I guess, first of all, there is no rate increase proposed in this Application, we’re proposing a rate decrease.

And secondly, I don’t agree with your premise that or -- or I guess your premise that we should be held accountable for a mistake that the company made.

It’s our position that we -- we made no mistake, we implemented what we were allowed to implement and there was obviously some mis-communication, so we are in a position today to say, there is no back billing, because back billing would imply that the company made a mistake. And we don't agree to that.

MR. BILL CARROLL: I guess MacDon is -- is of a position that they're one (1) of the companies that has brackets around their numbers and they feel like they paid forty-three hundred dollars ($4,300) or whatever too much.

And they believe, that until this Board makes a determination that somehow the rates are going to change, that they were, in fact, charged too much. Is there a flaw in their thinking?

MS. MARLA MURPHY: I think, Mr. Chairman, that would constitute argument and we'll be pleased to address that next Wednesday.

THE CHAIRPERSON: You can see that, Mr. Carroll?

MR. BILL CARROLL: Sure. Thanks. Just an observation that earlier it was said when Ms. Derksen in answer to one of Mr. Peters questions that -- that this Board agreed with the methodology and sort of the implementation strategy went a little astray.

And I guess we're concerned by that, because if that is, in fact, the case, then MacDon has wasted a lot of time, energy and money if this is just a slam-dunk proceeding.

So that's part of that whole issue. I'll ask my last question now and I'm going to try and end on a positive note.

Are you giving serious consideration to implementing a parallel win/win program like PowerSmart for gas users? I know it was brought up last week. MacDon Industries has used the PowerSmart program many, many times. And I think that it is a win/win situation.

And I guess I'd like to know if the Utility is, sort of, heading in that direction for gas?

MR. VINCE WARDEN: We are -- Mr. Carroll, we are definitely heading in that direction, whether it will directly impact MacDon Industries initially is -- is undecided at this point in time.

But, are in the midst of developing a program which we will be bringing forward to Manitoba Hydro's Board for approval initially and then hopefully launching it early next year.

MR. BILL CARROLL: Thank you, Mr. Chairman. Those are my questions.

THE CHAIRPERSON: Thank you Mr. Carroll. And thank you everyone else. And we'll see you back all tomorrow morning.

(PANEL STAND DOWN)

--- Upon adjourning at 4:11 p.m.

Certified Correct

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Carol Wilkinson
Court Reporter