MANITOBA PUBLIC UTILITIES BOARD

Re: CENTRA GAS MANITOBA INC.

2006/07

COST OF GAS APPLICATION

Before Board Panel:

Graham Lane - Board Chairman

Monica Girouard - Board Member

Alan Molgat - Board Member

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

November 27th, 2006

Volume I

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APPEARANCES

R.F. Peters	)Board Counsel
Marla Murphy	)Centra Gas
Brent Czorneki	)
Eric Hoaken	)Direct Energy Marketing
Andrea Gibbs	)Limited/Municipal Gas
Nola Ruzycki	)Energy Saving (Manitoba)
	)Corp.
Kris Saxberg	)CAC/MSOS

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--- Upon commencing at 9:10 a.m.

THE CHAIRPERSON: Good morning, everyone. If I could please have your attention, I'd like to call these proceedings to order.

Welcome to the Public Hearing in respect of Centra Gas Manitoba Inc.'s Annual Cost of Gas matters. I see some familiar faces in the Hearing Room as well as some new faces and welcome all of you. The Board looks forward to your assistance in explaining the various issues that are before this Panel.

I am Graham Lane, Chairman of the Public Utilities Board. I'm joined in the Hearing Panel by Ms. Monica Girouard who has dealt with natural gas issues for several years and Mr. Alan Molgat to my left.

I want to welcome Mr. Molgat to his first cost of gas hearing. I look forward to working with him and Ms. Girouard on the issues that are before the Board. The Board is also assisted by the Executive Director, Mr. Gerry Goudreau, and Associate Secretary Mr. Hollis Singh.

By way of brief background information Centra requires approval from this Board prior to changing rates. Primary gas rates are adjusted quarterly pursuant to Board-established procedures.

Non-primary gas rates which include

supplementary gas, transportation, and unaccounted for gas are usually adjusted on an annual basis through cost of gas hearings such as the present one. Distribution rates and basic monthly charges are adjusted through General Rate Application proceedings which occur approximately every two (2) years according to Centra's current scheduling.

This Hearing has had its genesis in interim application by Centra on June 16th of this year. Centra applied to the Board to reduce non-primary gas base rates by an aggregate amount of 6.6 million. In that interim application Centra also sought Board approval to refund the balances of various non-primary gas deferral accounts and purchased gas variance accounts in the aggregate amount of 13.2 million.

The Board sought comments of past Intervenors including all those registered for this proceeding. After considering Centra's interim application together with the submissions from interested parties the Board Issued Order 116/06.

In Order 116/06 the Board addressed the number of matters related to Centra Gas costs and approved the requested reduced non-primary gas rates as well as the refund, a non-primary gas PGVA and deferral account balances to consumers.

The Board also directed Centra to file an annual cost of gas application to review and finalize the decisions of Order 116/06 rather than wait until the next presently unscheduled GRA which leads us to the present application.

On September 13th, 2006, Centra filed an application with this Board seeking to finalize the rate decisions of the Board as contained in Interim Order 116/06. The Board also wanted Centra to ensure its annual cost of gas filing contained sufficient information as so as to allow the Board to review the usual matters that are considered at a cost of gas hearing.

Some of those usual matters were set out at pages 22 of 32 in Order 116/06 and Centra's application also addresses those issues.

The Board was pleased to grant Intervenor status in Order 136/06 to the Consumers' Association of Canada (Manitoba) Inc., Manitoba Society of Seniors, I see Mr. Saxberg, Direct Energy Marketing Ltd, the parent company Municipal Gas and Energy Savings Manitoba Corp.

As noted in Order 136/06 the Board dispensed with the normally held pre-hearing conference for this cost of gas hearing and the Board regrets any confusion that may have resulted from a lack of pre-hearing conference as to the scope of this Hearing.

Board Order 115/06, dated not that long ago, November 17th, 2006, sought to clarify the scope of this Hearing by indicating the various matters in Direct Energy Marketing Ltd.'s pre-filed evidence, were beyond the contemplated scope of this proceeding.

However, there is a silver lining. Direct Energy has assisted the Board in consideration of some of the issues that need to be explored in determining the appropriate type of competitive marketplace that should be sought in the public interest in Manitoba, including the role of the regulated utility in that marketplace.

Should any party want to provide the Board with a listing of issues that should be considered in a subsequent proceeding, please feel free to do so in your closing submissions. The Board will consider the process to be utilized to permit such a market review.

Back to the application at hand. The Board expects to hear the parties' positions and evidence on the review and finalization of gas cost incurred and the forecast non-primary gas cost to be incurred by Centra.

So I now turn to Mr. Bob Peters, Board counsel, to provide his opening comments. Mr. Peters will also provide an outline of procedures that will assist the Board in this Public Hearing.

MR. BOB PETERS: Thank you and good morning, Mr. Chairman, Board Member Girouard, and a special welcome to Board Member Molgat, ladies and gentlemen. For the record, my name is Bob Peters and I act for the Board as counsel for this proceedings.

Mr. Roger Cathcart, chartered accountant of Price Waterhouse Coopers, seated to my left, is from the Board's accounting advisors. And Messrs. Myron Kostelnyk and Brady Ryle (phonetic), professional engineers of Energy Consultants International, the Board's engineering advisors, are seated to my right; they also assist in this matter.

May I take the liberty of indicating to Board Member Molgat that as you embark on your first cost of gas hearing all counsel and witnesses want to do their best to ensure that all of the issues are adequately explained. And if there are questions of clarification to assist your understanding, please don't hesitate to let us know.

I also want to welcome Mr. Brady Ryle to the advisory team and thank him for his assistance in this matter.

In my introductory comments I intend merely to summarize -- to summarize the case before the

Board without adopting or advocating any particular position on behalf of the Board. My comments will also address the process and the procedures to be followed during the course of this Hearing. And additionally, I will take the liberty of formally entering all exhibits to be filed on behalf of the Board and the parties present.

Ladies and gentlemen, on June the 16th, 2006, as the Chairman indicated, Centra applied to the Board for an interim order approving supplemental gas transportation and distribution rates to be effective for all gas consumed on and after August the 1st, 2006. Those requests included a decrease in the 2006/07 forecast non-primary gas base rates of $6.6 million based on a May 1st, 2006 twelve (12) month forward price strip for natural gas.

Centra also sought permission to refund approximately $13.2 million of the March 31st balances of various non-primary gas, purchased gas variance accounts and gas deferral accounts, together with the carrying cost up to July 31st of '06.

There was also the removal of rate riders that were refunding the March 31, 2005 balances of the various non-primary gas PGVA's and gas cost deferral accounts, together with carrying cost also to July 31st, 2006, and the proposal was to refund those over a twelve (12) month period.

As well, earlier this fall Centra requested the Board to approve primary gas rates effective August 1st on an interim basis, in accordance with the rate setting methodology and process that this Board has approved in its Orders 55 of '00, 99 of '01, 143 of '03 and 69 of '04. The primary gas forecast were based on the July 3rd, 2006 twelve (12) month forward strip.

Following an opportunity for input by the various parties, on July 31st the Board issued Order 116 of '06 that approved both of Centra's requested rate applications as filed and on an interim basis.

The new rates implemented on August 1st resulted in a decrease of approximately 2.9 percent or forty dollars ($40) per year for the typical residential customer related to non-primary gas rates. There was also an additional decrease related to primary gas rates of 4.2 percent or fifty-seven dollars ($57) per year for that typical residential customer. The combined impact of these decreases was approximately 7 percent or ninety-six dollars ($96) a year.

While granting interim approval of Centra's requests, the Board required Centra file additional material in support of its June 16th, 2006/07 non-primary gas cost application and the Board also wanted Centra to respond to and update the Board and the parties on the status of a number of outstanding matters that were raised in prior Board Orders as well as in Order 116 of '06.

Centra filed the requested material on approximately September 13th and in that application that brings us here today, there's -- Centra is seeking final approval of the August 1st, 2006 rates that were given interim approval in Order 116 of '06 and that's based on the forecast of 2006/07 non-primary gas costs which will decrease according to that forecast by approximately $6.6 million.

There's approval for the refund of the deferral account balances of $13.2 million that is sought on final basis.

Centra also asks for final approval of the 2005/06 gas costs which are approximately $389.7 million according to the material. Centra's asking for approval of approximately seven (7) interim orders previously issued by the Board approving primary gas rates, as well as, four (4) other orders dealing with supplemental gas, transportation rates and distribution rates since 2004.

There are four (4) interim order extant in

Manitoba related to new or amended franchise applications and agreements together with the feasibility tests that underpin those and that is for the extension of gas service to customers in three (3) rural municipalities, again for which Centra is now seeking final approval.

And as a catch all, Centra has requested final approval of any other interim orders issued by the Board prior to the conclusion of this Hearing. And in that regard, the parties will be aware that on October 25th of 2006, the Board granted interim approval of Centra's request for primary gas rates effective November 1st, 2006.

That interim order was Order 144 of '06. In that Order primary gas were forecast using an October 2nd, twelve (12) month forward strip and on an annualized basis, the November 1st rates resulted in a 1.1 percent rate decrease which meant approximately fourteen dollars ($14) per year for the typical residential consumer.

In Tab 8 of the application, Centra has also provided updates to the Board and the parties present related to matters that have been previously discussed with the Board and that includes the natural gas storage, the western transportation service, derivatives hedging policy, future gas supply contracts, broker costs, class structure and basic monthly charge, as well as, the 2005/06 audited financial statements that were requested by the Board.

Mr. Chairman, that summarizes the application before you as I presently understand it, but before I turn to matters of procedure, like you, I should also comment on Board Order 155 of '06, which was dated November 17, '06 in which the Board sought to clarify the issues that would be considered in this Hearing, by ruling on a motion by Centra to exclude the evidence of Direct Energy Marketing Limited.

The Board's Order 155 of '06 confirmed the scope of this Hearing is to review and finalize prior years gas costs, as well as, the forecast non-primary gas costs for 2006/07.

The Board also clarified that this Hearing would not examine possible new market structures for Manitoba, including one in which Centra would be a default supplier of natural gas with a single regulated rate offering and in which the sale of natural gas, in all other respects, would be conducted by marketers and brokers.

The Board expressly indicated it is not within the scope of this current proceeding to consider the implementation of a new market structure in which Centra's role in the natural gas market would be under review.

The Board did indicate that it will consider instituting a special proceeding in 2007 which will allow for the thorough examination of the natural gas landscape in Manitoba.

Parties may choose to take you up, Mr. Chairman, on your offer in their closing comments and indicate the types of issues that they suggest the Board should include in the scope of that future hearing.

If I can turn to the procedures for the current proceeding, I have distributed an outline of proceedings on blue paper, just to keep it straight and I'll quickly walk through those.

As you can note, we are in the process of the opening comments and following my opening comments I will suggest to the Chairman that he call on the Intervenors in alphabetical order for introductions and opening comments, followed by asking Centra's counsel for her opening comments.

The Intervenors that have registered, as you've noted, Mr. Chairman, Consumers' Association of Canada Manitoba Inc., and the Manitoba Society of Seniors have a joint intervention. Mr. Kris Saxberg is counsel for them.

Direct Energy Marketing Limited is

represented today, and I welcome to Manitoba Mr. Eric Hoaken. I can say, Mr. Chairman, that Mr. Hoaken and I do disagree on our football matters but we do both agree that the Bombers or the Argonauts would have put up a better fight in the Grey Cup game.

Having said that, Mr. Hoaken is with Ms. Andrea Gibbs, the -- from Direct Energy's, Manager of Government and Regulatory Affairs. And also Mr. Hoaken is with Mr. Gary Newcombe who is Direct's Vice President, Government and Regulatory Affairs for Canada West.

Energy Savings Manitoba Corp., as ESMC is the acronym we've applied, is represented by Nola Ruzycki, and she is also present today.

In terms of the evidence for this proceeding, Mr. Chairman, it is anticipated that Centra will have the five (5) witnesses who are before you today. They will be introduced and sworn to provide their evidence through the leading of their counsel. After their direct evidence is provided they will be cross-examined firstly by myself, then by Intervenors, again in alphabetical order, unless the Intervenors have some agreement amongst themselves that varies that, and then re-examination if requested.

It is dangerous, Mr. Chairman, as you know, and, Mr. Molgat, you will learn that my reputation suffers greatly when I try to project how long these hearings will go. But in discussions with my colleagues I'm anticipating my questions of this Panel to -- to take up the balance of today and spill into tomorrow. Mr. Saxberg will, if not finish his questions tomorrow, will spill into Wednesday morning. And then on Wednesday Direct Energy and Energy Savings Manitoba Corp. expect their questions will be asked and answered. And that will conclude, I believe, the evidence from Centra.

We have scheduled through Mr. Saxberg's office for the evidence of Mr. Ashmead Pringle of GSC Energy to take place on Thursday of this week. And I should alert parties that on Thursday, due to a prior Board commitment, there will be an extended lunch hour from approximately 11:30 until two o'clock, but we still anticipate that Mr. Pringle's evidence will be concluded on Thursday.

The closing submissions, Mr. Chairman and Board Members, have yet to be finalized and I will be seeking confirmation this morning and I will bring it back to the Board for their confirmation of availability. It is anticipated that, as we will finish this week on Thursday, we are targeting perhaps next Wednesday, December the 6th, as the day of argument.

And that argument would start off with my closing comments in summary form. I would be followed by Mr. Saxberg on behalf of CAC/MSOS. And I believe that Mr. Hoaken and possibly also Ms. Ruzycki will be interested in filing written comments with the Board that will be read -- taken as read and put into the transcript of the proceedings.

And then, after that is done, depending on the time it takes, Centra may be prepared to provide its closing submissions later on in the day on Wednesday. So I'll work on that a little further and I'll get back to the Board and the parties with confirmation on that.

I would also like to turn to the exhibits, Mr. Chairman. And on behalf of the parties present an exhibit list has been prepared. I do have a few revisions, so I will ask you to have your pens handy and we'll -- we'll go through the exhibit list.

PUB Exhibit 1 will be the Notice of Hearing.

--- EXHIBIT NO. PUB-1 Notice of Hearing dated September 7, 2006

MR. BOB PETERS: And PUB-2 will be the Procedural Order 136 of '06.

--- EXHIBIT NO. PUB-2 Procedural Order No. 136/06
dated September 29, 2006

MR. BOB PETERS: And PUB-2-1 will be the Order, also procedural in nature, 155 of '06, to which I have already referred.

--- EXHIBIT NO. PUB-2-1 Order No. 155/06 dated
November 17, 2006

MR. BOB PETERS: Then Exhibits PUB/CENTRA-3-1 through 3-68 will be the Information Requests posed on behalf of the Board together with Centra's responses.

--- EXHIBIT NO. PUB/CENTRA-3-1
The Public Utilities Board's Information
Requests and Centra Gas Manitoba Inc.'s
Response. Materials filed on June 16/06
--- EXHIBIT NO. PUB/CENTRA-3-2
The Public Utilities Board's
Information Requests and Centra
Gas Manitoba Inc.'s Response.
Table displaying all primary &
Non-primary gas cost rate changes

for 5 years.
--- EXHIBIT NO. PUB/CENTRA-3-3
The Public Utilities Board's
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Changes to Centra's gas supply
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--- EXHIBIT NO. PUB/CENTRA-3-4
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--- EXHIBIT NO. PUB/CENTRA-3-5
The Public Utilities Board's
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Direct purchase and system
customers by class and quarter
including normalized volumes
--- EXHIBIT NO. PUB/CENTRA-3-6
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Table displaying actual volumes

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--- EXHIBIT NO. PUB/CENTRA-3-7
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--- EXHIBIT NO. PUB/CENTRA-3-8
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--- EXHIBIT NO. PUB/CENTRA-3-9
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--- EXHIBIT NO. PUB/CENTRA-3-10
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--- EXHIBIT NO. PUB/CENTRA-3-11

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response Confirmation of no further changes to 05-06 gas costs, March 31/06 non-primary PGVAs and other gas cost deferral account balances.

--- EXHIBIT NO. PUB/CENTRA-3-12

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response Centra's UFG volumes and related costs for last five years

--- EXHIBIT NO. PUB/CENTRA-3-13

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response Status of Bill 11

--- EXHIBIT NO. PUB/CENTRA-3-14

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response Monthly unutilized demand charges

paid to TCPL, exchange rates,
variance breakdown between forecasts
and actual amounts and hedging impacts,
PGVA inflows reconciliation

--- EXHIBIT NO. PUB/CENTRA-3-15

The Public Utilities Board's
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How estimated capacity management
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10 year historic records and number of
transactions conducted by Centra in 05/06

--- EXHIBIT NO. PUB/CENTRA-3-16

The Public Utilities Board's
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Gas Manitoba Inc.'s Response
2006/07 Gas cost forecast is based
on forecast forward price strips

--- EXHIBIT NO. PUB/CENTRA-3-17

The Public Utilities Board's
Information Requests and Centra
Gas Manitoba Inc.'s Response
Methodological changes initiated
by Centra for forecasting SGS
and LGS customers

--- EXHIBIT NO. PUB/CENTRA-3-18
The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response WTS service historical records for percentage of customers in SGS residential commercial and LGS classes on an annual basis.

--- EXHIBIT NO. PUB/CENTRA-3-19
The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response Determination of normal degree days used by Centra

--- EXHIBIT NO. PUB/CENTRA-3-20
The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response Details of efficiency improvement assumptions, DSM factors that impact average customer use and annual volume determination for SGS and LGS classes.

--- EXHIBIT NO. PUB/CENTRA-3-21
The Public Utilities Board's

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of estimating volumes

--- EXHIBIT NO. PUB/CENTRA-3-22
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Definition of average number of
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--- EXHIBIT NO. PUB/CENTRA-3-23
The Public Utilities Board's
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Derivation of the average inventory
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--- EXHIBIT NO. PUB/CENTRA-3-24
The Public Utilities Board's
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Updates related to any current or
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--- EXHIBIT NO. PUB/CENTRA-3-25

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response Support for calculations resulting in selecting US exchange rate for 06/07

--- EXHIBIT NO. PUB/CENTRA-3-26

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response Explanation why Centra only contracted 50 percent of eligible volumes for Feb 07-Apr 07

--- EXHIBIT NO. PUB/CENTRA-3-27

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response Update of schedule 5.3.1 segregated between settled and unsettled transactions.

--- EXHIBIT NO. PUB/CENTRA-3-28

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response

Confirmation of functionalization of
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--- EXHIBIT NO. PUB/CENTRA-3-29

The Public Utilities Board's
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Changes to GRA since last GRA
related to Customer numbers, annual
volumes, load factors, monthly
billing determinations and
classification and allocation factors

--- EXHIBIT NO. PUB/CENTRA-3-30

The Public Utilities Board's
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Expansion of table in section 6.4
displaying commodity and capacity
components of total cost allocation
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--- EXHIBIT NO. PUB/CENTRA-3-31

The Public Utilities Board's
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Reconciliation of non-primary gas
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--- EXHIBIT NO. PUB/CENTRA-3-32

The Public Utilities Board's
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--- EXHIBIT NO. PUB/CENTRA-3-33

The Public Utilities Board's
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Gas Manitoba Inc.'s Response
Discussion of any differences used
for the allocation of the non-primary
gas and other gas cost deferral
account balances to the customer classes

--- EXHIBIT NO. PUB/CENTRA-3-34

The Public Utilities Board's
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Gas Manitoba Inc.'s Response
Portions of WACOG "paid for" by each
customer class determined through

actual billing information

--- EXHIBIT NO. PUB/CENTRA-3-35

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response Centra's view of Board granting final approval of orders related to primary gas rate changes

--- EXHIBIT NO. PUB/CENTRA-3-36

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response Interim rural expansion orders final readings to the by-laws (4 R.Ms)

--- EXHIBIT NO. PUB/CENTRA-3-37

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response Overview of process and circumstances leading Centra to various methods of storage and transportation arrangements with ANR Pipelines

--- EXHIBIT NO. PUB/CENTRA-3-38

The Public Utilities Board's Information Requests and Centra

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Narrative explanation to effect and changes of any changes to the gas supply portfolio relative to the assumptions and findings in 2001 IGC review.

--- EXHIBIT NO. PUB/CENTRA-3-39

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response.
Table of Economics of Salt Cavern storage

--- EXHIBIT NO. PUB/CENTRA-3-40

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response.
Update WRT further developments in regard to Centra's Aug 3/05 report

--- EXHIBIT NO. PUB/CENTRA-3-41

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response.
EPP and the role it plays.

--- EXHIBIT NO. PUB/CENTRA-3-42

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The Public Utilities Board's
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--- EXHIBIT NO. PUB/CENTRA-3-47

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response.
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--- EXHIBIT NO. PUB/CENTRA-3-55
The Public Utilities Board's
Information Requests and Centra
Gas Manitoba Inc.'s Response.
Derivative Hedging transactions

--- EXHIBIT NO. PUB/CENTRA-3-56
The Public Utilities Board's
Information Requests and Centra
Gas Manitoba Inc.'s Response.
Internal audit

--- EXHIBIT NO. PUB/CENTRA-3-57
The Public Utilities Board's
Information Requests and Centra
Gas Manitoba Inc.'s Response.
Centra's approved counterparites
for transactions

--- EXHIBIT NO. PUB/CENTRA-3-58
The Public Utilities Board's
Information Requests and Centra
Gas Manitoba Inc.'s Response.
Schematic diagram of the structure

including an organization chart of
those involved in derivative hedging
activities

--- EXHIBIT NO. PUB/CENTRA-3-59

The Public Utilities Board's
Information Requests and Centra
Gas Manitoba Inc.'s Response.
Market liquidity

--- EXHIBIT NO. PUB/CENTRA-3-60

The Public Utilities Board's
Information Requests and Centra
Gas Manitoba Inc.'s Response
Centra's policy on reducing
future gas costs

--- EXHIBIT NO. PUB/CENTRA-3-61

The Public Utilities Board's
Information Requests and Centra
Gas Manitoba Inc.'s Response
Centra's comments and observation
in respect to matter in tab 8
attachment 5

--- EXHIBIT NO. PUB/CENTRA-3-62

The Public Utilities Board's
Information Requests and Centra
Gas Manitoba Inc.'s Response

Summary of hedging activities for the past 24 months

--- EXHIBIT NO. PUB/CENTRA-3-63

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response Monthly average AECO prices chart for 03/04, 04/05 and 05/06

--- EXHIBIT NO. PUB/CENTRA-3-64

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response KIODEX Report, its tactics and utilization

--- EXHIBIT NO. PUB/CENTRA-3-65

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response Recommendation related to the appropriate level of BMC

--- EXHIBIT NO. PUB/CENTRA-3-66

The Public Utilities Board's Information Requests and Centra Gas Manitoba Inc.'s Response Overview of history around benefits of acquisition of Centra by Hydro

--- EXHIBIT NO. PUB/CENTRA-3-67

The Public Utilities Board's
Information Requests and Centra
Gas Manitoba Inc.'s Response
Financial statements and integrated
financial forecast CGM

--- EXHIBIT NO. PUB/CENTRA-3-68

The Public Utilities Board's
Information Requests and Centra
Gas Manitoba Inc.'s Response
Financial statements note 13

MR. BOB PETERS: Then PUB/CAC-MSOS 4-1 to 4-10, will be Information Requests posed on behalf of the Board and responded to by the witness being put forward by Consumers Association of Canada Manitoba Inc. and Manitoba Society of Seniors.

--- EXHIBIT NO. PUB/CAC/MSOS-4-1

The Public Utilities Board's
Information Requests and Consumers'
Association of Canada (Manitoba)
Inc./Manitoba Society of Seniors'
Response. Hedging and gas costs
reduction.

--- EXHIBIT NO. PUB/CAC/MSOS-4-2
The Public Utilities Board's Information Requests and Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors' Response. Volatility range

--- EXHIBIT NO. PUB/CAC/MSOS-4-3
The Public Utilities Board's Information Requests and Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors' Response. Hedging strategy

--- EXHIBIT NO. PUB/CAC/MSOS-4-4
The Public Utilities Board's Information Requests and Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors' Response. Exit Fees.

--- EXHIBIT NO. PUB/CAC/MSOS-4-5
The Public Utilities Board's Information Requests and Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors' Response. LDC's and the merchant function

--- EXHIBIT NO. PUB/CAC/MSOS-4-6

The Public Utilities Board's Information Requests and Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors' Response. Hedging, unregulated affiliate and regulations.

--- EXHIBIT NO. PUB/CAC/MSOS-4-7

The Public Utilities Board's Information Requests and Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors' Response. The equal payment plan

--- EXHIBIT NO. PUB/CAC/MSOS-4-8

The Public Utilities Board's Information Requests and Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors' Response. Hedged volumes

--- EXHIBIT NO. PUB/CAC/MSOS-4-9

The Public Utilities Board's Information Requests and Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors' Response. Market price, signals and rate stability.

--- EXHIBIT NO. PUB/CAC/MSOS-4-10
The Public Utilities Board's Information Requests and Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors' Response. Fixed price contract.

MR. BOB PETERS: You will note on pages 6 and 7 of the Exhibit list the exhibits marked 3-6 through 3-10, should actually be 4-6 to 4-10.

In turning to the exhibits for Centra Gas Manitoba, the first exhibit, Central Exhibit 1 would be their application and the correct date should read September 13th, 2006.

--- EXHIBIT NO. CENTRA-1: Centra Gas Manitoba Inc. Application dated September 13, 2006

MR. BOB PETERS: Exhibit Centra 2 will be the affidavit of publication and service of the notice. And that was provided in a letter of November 22nd, 2006 from Centra.

--- EXHIBIT NO. CENTRA-2-1: Affidavit of publication and service of Notice dated November 22/06

MR. BOB PETERS: Centra-CAC/MSOS 3-1 through to 3-30, will represent the questions posed on behalf of Centra Gas and responded to by Mr. Pringle, witness put forward on behalf of CAC/MSOS.

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-1
Centra Gas Manitoba Inc.'s
Information Requests and Consumers'
Association of Canada (Manitoba) Inc.
/Manitoba Society of Seniors' Response
Rate smoothing tools.

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-2
Centra Gas Manitoba Inc.'s
Information Requests and Consumers'
Association of Canada (Manitoba) Inc.
/Manitoba Society of Seniors' Response
Rate smoothing other mechanisms

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-3
Centra Gas Manitoba Inc.'s
Information Requests and Consumers'
Association of Canada (Manitoba) Inc.

/Manitoba Society of Seniors' Response
Rising and falling markets
--- EXHIBIT NO. CENTRA/CAC/MSOS-3-4
Centra Gas Manitoba Inc.'s
Information Requests and Consumers'
Association of Canada (Manitoba) Inc.
/Manitoba Society of Seniors' Response
AECO price fluctuations 2002-2006
--- EXHIBIT NO. CENTRA/CAC/MSOS-3-5
Centra Gas Manitoba Inc.'s
Information Requests and Consumers'
Association of Canada (Manitoba) Inc.
/Manitoba Society of Seniors' Response
Customers and volatility tolerance
--- EXHIBIT NO. CENTRA/CAC/MSOS-3-6
Centra Gas Manitoba Inc.'s
Information Requests and Consumers'
Association of Canada (Manitoba) Inc.
/Manitoba Society of Seniors' Response
Costless collars - basis of choice
--- EXHIBIT NO. CENTRA/CAC/MSOS-3-7
Centra Gas Manitoba Inc.'s
Information Requests and Consumers'
Association of Canada (Manitoba) Inc.
/Manitoba Society of Seniors' Response

Centra goal to reduce price volatility

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-8

Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response Requirement to hedge

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-9

Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response Reduced rate volatility and no hedging

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-10

Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response Costless collars as a reasonable and prudent strategy

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-11

Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response

Hedging and exposure to price increases

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-12

Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response Volatility, low gas prices and market responsiveness

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-13

Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response Volatility and customer protection

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-14

Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response Centra as a hedger

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-15

Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response

Mitigating volatility

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-16

Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response A derived strategy

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-17

Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response Costless collars

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-18

Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response Summer re-fill hedges

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-19

Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response Summer versus winter prices

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-20
Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response Bill Shock

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-21
Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response Eligible volume

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-22
Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response Customers position on hedging

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-23
Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response Gas as a percentage of total bill

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-24

Centra Gas Manitoba Inc.'s
Information Requests and Consumers'
Association of Canada (Manitoba) Inc.
/Manitoba Society of Seniors' Response
Mechanical hedging programs

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-25

Centra Gas Manitoba Inc.'s
Information Requests and Consumers'
Association of Canada (Manitoba) Inc.
/Manitoba Society of Seniors' Response
Normal distributions

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-26

Centra Gas Manitoba Inc.'s
Information Requests and Consumers'
Association of Canada (Manitoba) Inc.
/Manitoba Society of Seniors' Response
Speculative trading

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-27

Centra Gas Manitoba Inc.'s
Information Requests and Consumers'
Association of Canada (Manitoba) Inc.
/Manitoba Society of Seniors' Response
CAC/MSOS exhibit

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-28

Centra Gas Manitoba Inc.'s

Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response CAC/MSOS exhibit 6 2001/02 Cost of Gas hearing

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-29
Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response Exhibit 2 2002/03 Cost of Gas hearing

--- EXHIBIT NO. CENTRA/CAC/MSOS-3-30
Centra Gas Manitoba Inc.'s Information Requests and Consumers' Association of Canada (Manitoba) Inc. /Manitoba Society of Seniors' Response Evidence dated June 3, 2003

MR. BOB PETERS: Notification last week that the rebuttal evidence would not be filed so Centra Exhibit 4 is not rebuttal evidence, but it is replaced by the witness qualifications that have been filed for the witness panel that is before you today.

--- EXHIBIT NO. CENTRA-4 Witness qualifications

MR. BOB PETERS: Exhibit 4-1 will be the witness qualifications for Mr. Vince Warden.

--- EXHIBIT NO. CENTRA-4-1 Witness qualification for Vince Warden

MR. BOB PETERS: 4-2 will be the witness qualifications for Mr. Howard Stevens.

--- EXHIBIT NO. CENTRA-4-2 Witness qualification for Howard Stephens

MR. BOB PETERS: Exhibit Centra 4-3, will be the witness qualifications for Ms. Lori Stewart.

--- EXHIBIT NO. CENTRA-4-3 Witness qualification for Lori Stewart

MR. BOB PETERS: Centra exhibit 4-4 will be the witness qualifications for Mr. Brent Sanderson.

--- EXHIBIT NO. CENTRA-4-4 Witness qualification for Brent Sanderson

MR. BOB PETERS: And Centra exhibit 4-5

will be the witness qualifications for Ms. Kelly Derksen.

--- EXHIBIT NO. CENTRA-4-5 Witness qualification for Kelly Derksen

MR. BOB PETERS: Mr. Chairman, ladies and gentlemen, there is one (1) additional Centra exhibit that will be filed and copies will be made available and I have them -- I have some copies as well if -- I don't believe the parties have all seen this letter.

It is a letter dated November 23rd, 2006 from Centra to the Board and this letter updates the timeline on the gas supply contract and portfolio review that will be talked about later in these proceedings.

It is my summary of the letter that there have been some slight delays in the timeline and to that end, the recommendations that the company, the Utility wants to review will be complete by the end of the calendar year 2006.

There will be internal reviews and approvals scheduled to take place in the month of January, 2007 and the Utility expects to file the documentation on Centra's Gas supply contract review in February 2007 with the Board. I'll have copies of that available for parties at the break.

--- EXHIBIT NO. CENTRA-5   Letter dated November 23/06
from Centra to the Board re
update timelines

MR. BOB PETERS: I then turn to the exhibits on behalf of the Consumer's Association of Canada, Manitoba Inc. and Manitoba Society of Seniors, on page 10 of the exhibit list and CAC/MSOS/Centra Exhibit 1-1 through to 1-67, will be the questions posed by CAC/MSOS and the responses by Centra to those questions.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-1
Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Response to observations and suggestions
WRT gas commodity, costs, pricing,
policy hedging

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-2
Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Derivatives hedging program - internal

administration costs

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-3

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Derivatives hedging program - embedded dealer costs/estimates.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-4

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Derivatives hedging program - measuring reduction in volatility (reduction internal/external costs and value setting for hedges.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-5

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Gas Supply Management Committee & Executive Committee (meeting 05-06, 06-07, hedging information sources, Web

Trader gas system)

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-6

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Hedging program - Exercise of judgment - qualifications, justification for decision making.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-7

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. '06-07 Hedge - positions behind the decisions made.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-8

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Hedging - Caps vs. Collars WRT Centra's retrospective analysis

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-9

Consumers' Association of

Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Hedging - Exercise of Discretion WRT
mechanistic hedging and counter parties

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-10

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Hedging - Exercise of Discretion WRT
mechanistic hedging and counter parties

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-11

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Hedging -information WRT primary gas -
purchasing, total customer bill,
quarterly gas bill rates.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-12

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.

Hedging - Information WRT to price volatility (spikes and declines), Nexen pays for base load volumes.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-13

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Centra's Retrospective review of derivatives hedging program for primary gas.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-14

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Fixed price offerings pricing alternatives to customer classes, fixed price contacts/ offerings.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-15

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Hedging oversight - detail of independent oversight

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-16

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Bill volatility

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-17

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Referenced schedules (Tab 5, schedule 5.2.3a&b) gas forecast costs.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-18

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Application tab 5 and related attachments /schedules - Aug. 1/06 forward strips and ex rates.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-19

Consumers' Association of Canada (Manitoba) Inc. And Manitoba

Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
UFG - update (75b) from last GRA

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-20

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Consumer conservation

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-21

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Exchange rate - forecasts 04-05, 05-06
06-07 with comparisons

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-22

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Customer forecasts - comparisons,
additions, historical comparisons by class

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-23

Consumers' Association of

Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Customer Forecasts - regression equation results, RGDP growth assumption

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-24

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Average Use Forecast - generation method by rate class, actual and normalized historical average.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-25

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. 06-07 Forecast comparison based on 05-06 forecast vs. actual

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-26

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response.

Application Tab 1, attachment 1 - determination of balance at March 31/06 for schedules 3.1.1-3.4.1.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-27

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Application tab 6/7, schedule 7.20. And 7.3.0 Appendix C - detailed cost allocations study of class rates

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-28

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Application tab 8, pp 8-10 (of 10) tab 5 schedule 5.1.1 - 5.1.5 - accuracy and reliance board and stakeholders should place on number of customers and volumes for the two categories of SGS

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-29

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests

and Centra Gas Manitoba Inc.'s Response.
Application tab 8 attachment 6
updated information in executive
study (p.3 & 4) for BMC based on
05-06 Cost Allocation Study

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-30

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Tab 8 attachment 6 - percentage of SGS
residential customers use of EPP
service & associated costs.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-31

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Appendix Centra provides meter plant
costs/customer

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-32

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.

IGC report - criteria for choosing, when it was commissioned, date completed, total cost, agreement and information provided.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-33

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. IGC and tab 8 attachment 1 p.3 - confirmation of Centra's position (Against recommendation of report)

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-34

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. IGC - changes report recommends

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-35

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. IGC - model used for design of portfolio

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-36

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. IGC - relative gas prices used in IGC report as its basis of analysis

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-37

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Salt Cavern Storage - Tab 8, attachment 1 - support for derivation of numerical results.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-38

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Tab 8, Attachment 1 p. 3-4 - security of supply WRT capacity on Western Section for TransCanada Mainline system

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-39

Consumers' Association of

Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Tab 8, Attachment 1 p.4 & 13 - detail explanation of capacity management arrangements and distinction between capacity management arrangement and delivered services.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-40

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Tab 8, attachment 1 p.5 - summer/winter differentials WRT average monthly market price.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-41

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Tab 8, Attachment 1 p.8 - distinctions between peaking and seasonal facilities.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-42

Consumers' Association of

Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Tab 8, Attachment 1 p.8 - benefits and
costs attributed to Salt Cavern report.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-43

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Tab 8, attachment 1 p.10 - regarding
ownership of proposed Sask. Facility

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-44

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Tab 8, attachment 1 p.11-12 -
development costs for MB and
SASK salt cavern storage facilities.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-45

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.

Tab 8, Attachment 1 p.12 - table
displaying annual benefits under 3
operational scenarios.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-46

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Tab 8, Attachment 1 p.13 - annual savings from salt cavern storage under various scenarios.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-47

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Tab 8, attachment 1 p.16 - results of sensitivity analysis.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-48

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Tab 8, Attachment 1 p.17 - effect changes to TransCanada tariff in relation to nomination windows.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-49

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Tab 8, Attachment 1. P. 19-20 - supply source recommendation WRT to shifting, acquiring, and implementation.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-50

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Tab 8, p. 8 - Economic and Environmental Analysis (EEA)

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-51

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Scope of the general enquiry undertaken with EEA - where to purchase gas supply from.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-52

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Gas supply contracting - pros and cons.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-53

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Gas supply - Nexen contract

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-54

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Update Schedules 75 03/04, Centra 13d
of 04/05 Cost of Gas Hearing

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-55

Consumers' Association of
Canada (Manitoba) Inc. And Manitoba
Society of Seniors' Information Requests
and Centra Gas Manitoba Inc.'s Response.
Update Schedules 76 03/04 GRA, 27
04/05 Cost of Gas Hearing (CGH)

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-56
Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Update Schedules 79g 03/04 GRA, 29 04/05 CGH

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-57
Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Update Schedules 81bg 03/04 GRA, 30 04/05 CGH

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-58
Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Update Schedules 85B 03/04 GRA, 32 04/05 CGH

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-59
Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests

and Centra Gas Manitoba Inc.'s Response. Update Schedules 104 03/04 GRA, 33 04/05 CGH

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-60

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Update Schedules 134 03/04 GRA, 34 04/05 CGH

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-61

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Dispatch rules used to determine the assets to be utilized to meet the load on any day.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-62

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Comparison of historical supplement gas supply mix.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-63
Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Peak Day - determination of optimal mix of supply sources.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-64
Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Capacity Management arrangements - tab 4, section 4.3, schedules 4.3.1 and 4.3.2. - references for capacity management revenues for 05/06 at aggregate levels.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-65
Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Tab 4, section 4.3 and schedules 4.3.1 and 4.3.2 - capacity release costs.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-66
Consumers' Association of

Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Finalizing Interim Orders.

--- EXHIBIT NO. CAC/MSOS/CENTRA-1-67

Consumers' Association of Canada (Manitoba) Inc. And Manitoba Society of Seniors' Information Requests and Centra Gas Manitoba Inc.'s Response. Centra's request for final approval of all accumulated gas cost deferral balances.

MR. BOB PETERS: And CAC/MSOS Exhibit 2 will be the evidence of Mr. Ashmead Pringle and again we expect Mr. Pringle's presence on Thursday of this week.

--- EXHIBIT NO. CAC/MSOS-2 Evidence of Ashmead Pringle

MR. BOB PETERS: For Direct Energy Marketing Limited, I have taken the liberty of entering an exhibit DEML-1 to be the letter from counsel for Direct to the Public Utilities Board dated November 22nd, indicating that in light of the clarifications from the Board in Order 155 of '06 as to the scope of the Hearing, Direct will not be filing evidence in this proceeding.

--- EXHIBIT NO. DEML-1 Letter dated November 22, 2006 from Eric Hoaken to The Public Utilities Board.

MR. BOB PETERS: For Energy Savings Manitoba Corp's exhibits, I suggest ESMC/Centra 1-1 through 1-4 be marked as the Information Requests by ESMC and the responses by Centra to those questions.

--- EXHIBIT NO. ESMC/CENTRA-1-1
ESMC's Information Requests and Centra Gas Manitoba Inc.'s Response Update on current status of Salt Cavern Storage.

--- EXHIBIT NO. ESMC/CENTRA-1-2
ESMC's Information Requests and Centra Gas Manitoba Inc.'s Response Fairness and appropriateness of current WTS arrangements

--- EXHIBIT NO. ESMC/CENTRA-1-3
ESMC's Information Requests and Centra Gas Manitoba Inc.'s Response Further research/comments by Centra in response to PUB Hedging Paper, and copies of all

correspondence, surveys, etc. with
CAC/MSOS

--- EXHIBIT NO. ESMC/CENTRA-1-4
ESMC's Information Requests and Centra Gas Manitoba Inc.'s Response Minutes of Gas Supply Committee of August 16, 2006 and subsequent follow-up.

MR. BOB PETERS: Mr. Chairman, Board Members, that completes my opening comments and subject to any questions you may have of me at this time I would suggest you turn to the counsel representing Intervenors who are present today and ask for their opening comments and introductions before turning to Centra's counsel for opening comments, introductions, and the swearing of the Witness Panel and proceeding with the evidence. Thank you, Mr. Chairman.

THE CHAIRPERSON: Thank you, Mr. Peters. Hearing no other questions of you, Mr. Saxberg, do you have opening remarks for CAC/MSOS?

MR. KRIS SAXBERG: Yes, thank you, Mr. Chairman, and good morning to you and good morning to other Board Members. A special welcome to Board Member Molgat.

And good morning to everyone else and it's nice to see familiar faces again. With me is Harry Paine who is the Vice-President of the Manitoba Society of Seniors and he along with Laurie Hunter (phonetic), the President of that organization will be monitoring this proceeding throughout.

Also with us Gloria Desorcy who is the Executive Director of the Consumers' Association of Canada and she as well will be monitoring this Hearing throughout.

I'd like to advise that the level of participation of CAC/MSOS will be full in this proceeding. We will cross-examine and test the evidence of Centra. We, as Mr. Peters indicated, are -- have sponsored a witness in the form of Ashmead Pringle the third, no less, to testify and he's expected to testify on Thursday. And we will then carefully consider all the evidence that's been presented and put our thoughts together so that the Board and Centra are aware of the consumers' views on the application and matters raised in this Hearing at least insofar as advocated by my clients.

And with that I will turn the mic over to whoever's next. Thank you, Mr. Chairman.

THE CHAIRPERSON: Thank you, Mr. Saxberg. Mr. Hoaken...?

MR. ERIC HOAKEN: Yes, thank you. Good morning. I'd like to thank everyone for the welcome that we have received except, of course, for the weather. As I think Mr. Peters mentioned I'm accompanied by Ms. Gibbs who's to my immediate left and Mr. Newcombe.

And just in terms of an opening I'd like to say we welcome the opportunity to participate in this Hearing.

In terms of background I'm sure that all of you know, but Municipal Gas is a division of Direct Energy and it has been an active participant in the market here since October of 1992. And it has an interest in a variety of the issues that are going to be raised at this Hearing.

When it sought Intervenor status it identified a few of those issues in particular that it wanted to focus on and one (1) of the key issues for us was the issue of hedging. And in the Intervenor forum that was submitted we said that we were interested in ensuring that Centra's hedging program and gas contracting proposals are such that they do not hinder or adversely impact the competitive impact -- or, excuse me, the competitive market in Manitoba.

And I quote that because I don't think I myself can put it any better, I didn't write that. But that really in a nutshell is the interest that Direct has in this proceeding and in the issues that are -- that are going to be raised in this proceeding.

And it's clear from the evidence that has been filed and from the interrogatories or Information Requests and responses and from the orders that have been made, that those issues of hedging are going to be part of this Hearing and so we certainly look forward to participating in the discussion and examination of those issues, and we hope to do so by way of cross-examination and ultimately submissions in a way that brings a perspective that otherwise might not be here before the Board and in a way ultimately, hopefully, that is helpful to the Board.

Now, both the Board Chair and My Friend Mr. Peters have made reference to the Board's Order 155/06, and that is an order that we're certainly grateful for in the sense that it clarifies what we are here to talk about. We also see it as a recognition that the issues that we have put forward are of interest to the Board and are considered to be important.

And I thank the Board Chair and Mr. Peters for their invitations to have us in the course of this proceeding and at the conclusion of the proceeding outline the issues that could be addressed in a future hearing that I understand the Board is now going to convene.

So that certainly will be part of the effort that we make to assist the Board in this Hearing. Thank you.

THE CHAIRPERSON: Thank you, Mr. Hoaken, and welcome.

Next up is Energy Savings, Ms. Ruzycki.

MS. NOLA RUZYCKI: Good morning and thank you, Mr. Chair, Board Members, ladies and gentlemen.

And I also would like to thank you for this lovely weather. It's the first snow we've seen this year. We went from I think plus twelve (12) yesterday to arriving at minus fifteen (15). So a little bit of a change in the weather for us.

My name if Nola Ruzycki with Energy Savings Manitoba Corp. And our main areas of interest in this cost of gas hearing includes Centra's derivative hedging program, Centra's natural gas storage, the future natural gas commodity supply contracts and the Board directives that were under Tab 8.

I'd like to thank you for your confirmation that the issues of Centra offering a fixed-price product will not be canvassed or addressed in this Hearing, and that we will provide comments in our closing submissions with respect to the 2007 process.

My participation in this Hearing mainly will be auditing and monitoring, but I will be asking questions if required. And I'm glad to be here.

THE CHAIRPERSON: Thank you.

Ms. Murphy, for Centra?

MS. MARLA MURPHY: Good morning, Mr. Chairman, Board Member Girouard and Board Member Molgat. Good morning, ladies and gentlemen.

I don't have any formal opening comments to make this morning. I would like to take the opportunity though to introduce Centra's Panel to you.

Seated immediately to my right is Mr. Vince Warden. Mr. Warden is the Vice President, Finance and Admin. and Chief Financial Officer for Centra. To his right, Mr. Howard Stephens, who is the Division Manager of Gas Supply. Then we have Ms. Lori Stewart, who's the Manager of Gas Supply, Transport and Storage. Beside Ms. Stewart is Mr. Sanderson, who's the Senior Gas -- sorry -- Senior Cost of Gas and Hedging Analyst, and finally Ms. Kelly Derksen, who is the Manager of Gas Rates and Regulatory.

I'd also like to take the opportunity to introduce those working in support of the people in the front row here, immediately behind us. Immediately behind me and perhaps hidden from some of you is Mr.

Brent Czornecki, who is my co-counsel. Beside him Ms. Carla Arletta, who is the Rate Analyst; Ms. Christine Foulkes, Regulatory Coordinator; Mr. Terrill Sigurdson, who is Gas Cost and Hedging Analyst, and finally Mr. Robin Wiens, who's the Division Manager of Rates and Regulatory for Centra.

Mr. Peters has raised with the Board the fact that the witness qualifications were filed by correspondence on Friday, the 24th. I believe they have now been assigned the exhibit numbers that we had proposed, being Exhibit CENTRA-4-1 through 4-5. I do have hard copies available for anyone who hasn't received them, and they've been left with the Board Secretary for the Board as well.

And subject to any questions you might have of us, the Panel is ready and available for examination.

THE CHAIRPERSON: Thank you, Ms. Murphy. We're quite familiar with the Panel.

Mr. Singh, would you mind swearing in the witnesses.

KELLY DERKSEN, Sworn

BRENT SANDERSON, Sworn

LORI STEWART, Sworn

HOWARD STEPHENS, Sworn

VINCE WARDEN, Sworn

THE CHAIRPERSON: Thank you Mr. Singh. As Jackie Gleason once said, and away we go!

Ms. Murphy...?

EXAMINATION-IN-CHIEF BY MS. MARLA MURPHY:

MS. MARLA MURPHY: Mr. Warden, could you please outline your areas of responsibility with respect to this filing?

MR. VINCE WARDEN: Yes. Good morning Mr. Chairman, Members of the Board, ladies and gentlemen, welcome to Mr. Molgat and to the new Members from Direct Energy for their first appearance here, welcome.

My areas of responsibility with respect to Centra's 2006/07 application to finalize gas costs relate primarily to policy issues and general oversight of the filing.

MS. MARLA MURPHY: Mr. Warden, would you please summarize what Centra's requesting with respect to gas rates in this application?

MR. VINCE WARDEN: Centra's requesting final approval of interim rates approved by the -- by the Board in Order 116/06 dated July the 31st, 2006.

In that Order the PUB approved, on an interim basis, change to Centra's supplemental gas, transportation and distribution to Centra rates, as well as the change to the distribution rate related to unaccounted for gas. In accordance with Order 116/06 Centra's rate were reduced effective August the 1st, 2006 to reflect a decrease in estimated non-primary -- primary gas costs of 6.6 million for fiscal year 2006/07.

The rate changes effective August the 1st -- August the 1st 2006, also reflected the elimination of the then existing rate riders and the introduction of new rate riders to refund to customers the estimated balance of $13.2 million in the non-primary gas PGVA accounts and other gas cost deferral accounts as at March 31st, 2006.

The changes in rates on August the 1st, 2006 resulted in annualized bill decreases to typical residential customers of approximately 2.8 percent or thirty-nine dollars ($39) per year. Non-gas costs were not effected by Order 116/06.

MS. MARLA MURPHY: Mr. Warden, one of the directives in Order 116/06 was that Centra file its updated financial forecast by November 30th of 2006, with an indication as to whether it will file a General Rate Application in early 2007.

Could you please provide an update on the status of this?

MR. VINCE WARDEN: Yes, Centra filed its updated financial forecast with the PUB as part of its response to Information Request PUB/Centra 67. In that financial forecast, non-commodity rate increases of 2.0 percent, effective May the 1st, 2007, and 1.0 percent, effective May the 1st, 2008, are projected.

It is Centra's intention to file a General Rate Application with the PUB early in the new year requesting approval of those projected rate increases. Should the projected rate increases be approved by the PUB, Centra is projecting net income of $6 million in 2007/08 and $7 million in 2008/09.

That level of net income will allow Centra to move gradually towards its debt equity target of 75/25 which is identical to the debt equity target of the electricity side of our business.

I would also like to take this opportunity to update the Board on the financial results of Centra for the current fiscal year. The recent released quarterly report of the Manitoba Hydro Electric Board for the six (6) months ended September the 30th, 2006, indicated that Centra incurred a net loss in operations of 26 million, compared to a net loss of $24 million for the same six months last year.

A loss at this time of the year is due to seasonal variations in the demand for natural gas and it is expected that this loss will be largely recouped over the winter heating season.

The reduction in net income compared to last year is mainly attributable to a quite significant decline in the average use per customer, together with approximately 20 percent warmer -- warmer temperatures compared to the prior year.

Overall, Centra's financial forecast projects a net loss for the current fiscal year of 1.4 million, however, if we have normal weather -- normal winter -- winter weather -- we should do somewhat better than that and Centra's financial results should be close to break even by year end.

The September quarterly report also referenced an average 7 percent annualized natural gas rate decrease for residential customers effective August the 1st, 2006, and annualized rate decreases between 7 percent to 9.3 percent for non-residential customers effective the same date.

Since the release of the quarterly report residential customers have had further annualized primary gas rate decrease of 1.1 percent effective November the 1st, 2006, and non-residential customers had decreases ranging -- ranging from 1.2 percent to 1.9 percent also effective November the 1st, 2006.

MS. MARLA MURPHY: Mr. Warden, in Order 135/05 and in Order 116/06 and further in a discussion paper dated August of 2006, the PUB encouraged Centra to consider other options to its current mechanistic hedging program. Has Centra done this?

MR. VINCE WARDEN: Yes, we certainly considered very carefully the comments of the PUB and others. In fact we did deviate from the purely mechanistic approach to placing derivatives on two (2) occasions in October 2005 and in April 2006. On both of those occasions hedges were placed on only 50 percent of eligible volumes for the applicable forward months.

In so doing, however -- however, we were still working within the parameters of the approved derivates hedging policy, a policy that was approved by both the Manitoba Hydro Board and the Public Utilities Board.

The approved policy allows for the placement of hedges at less than 100 percent of eligible volumes with the specific approval of Manitoba Hydro's executive committee.

MS. MARLA MURPHY: Mr. Warden, you've made reference to two (2) occasions on which the executive committee decided to hedge less than 100 percent of eligible volumes. Could you please comment further on those occasions?

MR. VINCE WARDEN: Like everyone else, in October 2005, Hydro's executive committee was very concerned about the high natural gas prices and the impact that those high prices would have on consumers. Of course we had no knowledge of where prices might go in the future, but we thought it was reason -- it was a reasonable assumption that the high prices may in part be attributable to the aftereffects of hurricanes Katrina and Rita and to the extent that this was the case, prices should moderate in the near term

On that basis Hydro's executive committee, at its meeting of October the 18th, 2005, decided to hedge 50 percent of eligible volumes for the months of August 2006 through October 2006.

By the time of the next quarterly hedging session, in January 2006, prices had not moderated. This was now five (5) months after Katrina and prices remained persistently high. There were predictions of oil going to a hundred dollars ($100) per barrel. Clearly there remained upside potential in natural gas prices.

Accordingly, at its meeting of January the 10th, 2006, the executive committee approved the placement of derivatives on 100 percent of eligible volumes for the month -- months of November and December 2006 and January 2007.

The next quarterly hedging session was in April 2006, and again the forward market appeared to be higher than what could be reasonably expected given the exceptionally mild winter of 2005/'06 and high natural gas inventories.

On this basis, the executive committee decided to defer hedging 50 percent of eligible volumes for the months of February, March, and April 2007.

Since April 2006, forward prices have declined and the quarterly hedging sessions of July 2006 and October 2006, derivates -- derivatives have been placed at 100 percent of eligible volumes in accordance with our normal derivatives hedging policy.

MS. MARLA MURPHY: Mr. Warden, could you please describe for the Board what Centra is doing to assist its low-income customers during periods of high natural gas prices.

MR. VINCE WARDEN: I would first like to say that Manitoba Hydro takes considerable pride in being recognized in the recently released annual report of the Canadian Energy Efficiency Alliance as being the top province in Canada in terms of reducing energy demand and consumption through conservation efforts.

Manitoba was the only province in Canada to receive an A rating and was described by the Alliance as the shining star. The Canadian Energy Efficiency Alliance is the leading non-government energy efficiency advocacy organization in Canada.

Referring again to the September 2006 quarterly report of the Manitoba Hydro Electric Board, it's reported that Manitoba Hydro has provided over $100 million in Power Smart loans to residential customers since the program was introduced in 2001.

The program has provided low-interest loans to approximately twenty-nine thousand (29,000) customers for purposes of improving the energy efficiency of their homes. The program was further enhanced in February of this year when the maximum amount that a customer can borrow under the program was increased from five thousand dollars ($5,000) to seventy-five hundred dollars ($7,500).

Some other initiatives to assist low-income consumers include the Neighbours Helping Neighbours Program, which has now been expanded to the Brandon -- the Brandon/Westman area and a partnership with the Community Education and Development Association to pilot a community-based approach for bringing Power

Smart to a hundred and twenty (120) low-income households in the Centennial neighbourhood of Winnipeg.

This project involves a new aboriginal construction enterprise and the hiring and training of six (6) aboriginal people to weatherize, insulate and install other energy-saving measures in these homes.

In addition, with the recent proclamation of sections of the Winter Heating Cost Control Act, specifically those sections referencing people on low incomes and seniors, Manitoba Hydro will be moving forward with low-income energy efficiency initiatives using the funding provisions contemplated by that Act.

MS. MARLA MURPHY: Mr. Warden, does Centra have any plans to submit an application to the PUB requesting approval of a fixed-price offering?

MS. MARLA MURPHY: Centra has done considerable research into the pros and cons of entering a fixed-price retail primary gas market but has not yet reached the stage where we are ready to take a recommendation to the Board of Centra.

An important step before we -- before we take a recommendation forward is to conduct customer research to determine whether our customers want us in that marketplace. We intend to conduct that customer research early in 2007.

MS. MARLA MURPHY: Finally, Mr. Warden, could you please update the Board on the status of Centra's gas supply contract.

MR. VINCE WARDEN: Yes. Our gas supply contract with Nexen Energy expires on October 31st, 2007, and we have engaged a consultant, Energy and Environmental Analysis Incorporated, to provide us with a recommendation to either replace or renew the existing supply contract.

In the event that we decide to replace our existing contract the consultant will assist us in drafting an RFP. We expect to have the consultant's recommendation by the end of December, and after appropriate internal reviews we will provide the PUB with all relevant documentation by February 2007.

Thank you.

MS. MARLA MURPHY: Thank you, Mr. Warden.

Mr. Stephens, would you please outline your areas of responsibility with respect to this application.

MR. HOWARD STEPHENS: Good morning, Mr. Chairman, Members of the Board, ladies and gentlemen.

In my testimony I will be providing evidence with respect to Centra's gas supply, storage and transportation arrangement, and Centra's capacity management program and results.

MS. MARLA MURPHY: Mr. Stephens, have there been changes to Centra's gas supply, storage and transportation arrangements since the 2005/'06 and 2006/'07 General Rate Application reflected in this application?

MR. HOWARD STEPHENS: No. There have been no changes to Centra's gas transportation arrangements since 2005/'06 and the 2006/'07 General Rate Application.

The primary gas range was put in place in November 2004 as Mr. Warden mentioned, will expire October 31, 2007, unless -- unless renewed for a further term by mutual agreement by both parties.

MS. MARLA MURPHY: Mr. Stephens, could you please provide the Board with an update on Centra's gas supply re-contracting efforts?

MR. HOWARD STEPHENS: Certainly. Centra has developed a comprehensive plan to ensure gas supplies are accorded -- in accordance with Centra's mandate and in compliance with the prior directives from the Board.

Several significant milestones have been achieved in that regard, including completion of the terms of reference and request for proposals, selection criteria and ultimately engaging energy and environmental analysis to assist in selection of appropriate gas supplier or suppliers.

Consultation with various external stakeholders to determine any specific needs or requirements to be considered in the contracting process. We have undertaken preliminary discussions with Nexen Marketing regarding the potential terms of the renewal of the existing agreement.

Development of the request for proposal to be -- to obtain quotations from various suppliers has been initiated. And in consultation with the consultant we have developed a comprehensive list of potential gas suppliers.

Centra now anticipates filing the various documents requested by the Board in February 2007.

MS. MARLA MURPHY: Mr. Stephens, could you please provide the Board with a brief update on the recent TCPL regulatory proceedings and the impact of those proceedings on Centra?

MR. HOWARD STEPHENS: I will. The 2004 tolls and tariff application phase II decision was issued on April the 15th, 2005.

This resulted in the application for and approval of interim mainline tolls effective July 1st, 2005, which resulted in a decrease in Manitoba tolls of approximately $2.25 million on an annualized basis relative to normalized volumes in Centra's 2006/'07 interim application -- that's a mouthful.

Subsequently an uncontested application was filed which resulted in approval of interim mainline tolls effective January 1st, 2006, resulting in a decrease in Manitoba tolls of approximately two hundred thousand dollars ($200,000) on an annual basis, relative to normalized volumes in Centra's 2006 interim application.

A third interim application was approved for interim mainline tolls to be effective March 1st, 2006 which resulted in a decrease again of approximately $1.5 million on an annualized basis, relative to the normalized volumes in Centra's 2006/'07 interim application.

TCPL has entered into negotiations with the tolls task force with the intent to have final tolls in place for January 1st, 2007. That process is just beginning and underway.

MS. MARLA MURPHY: Finally, Mr. Stephens, have there been any changes to Centra's capacity management program since the 2005/'06 and 06/'07 General Rate Application?

MR. HOWARD STEPHENS: There have been no

-- as I indicated before, there have been no changes to Centra's capacity management program for the 2005/'06 fiscal year.

Actual capacity management revenues together with carrying costs, total approximately $5.9 million as shown in schedule 4.3.1. The particulars of the types of transactions and revenues generated from each are detailed on that schedule.

For the 2006/'07 fiscal year, Centra's forecast capacity revenue -- capacity management revenues of $4.5 million based on the most recent five (5) year rolling average of Centra's actual capacity management results.

These forecast amounts have been included as a reduction in the approved base rates on August 1st, 2006.

MS. MARLA MURPHY: Thank you, Mr. Stephens. Ms. Stewart, would you please outline your areas of responsibility with respect to this application?

MS. LORI STEWART: Good morning, Mr. Chairman, Members of the Public Utilities Board, ladies and gentlemen.

In my testimony, I will be providing evidence with respect to Centra's derivatives hedging program and its results.

I will also be addressing any questions that may arise with regard to Centra's western transportation service.

MS. MARLA MURPHY: Ms. Stewart, have there been changes to Centra's hedging policy, operating principles and procedures or practices since the 2005/'06 and '06/'07 General Rate Application?

MS. LORI STEWART: There have been no changes to Centra's hedging policy and associated operating principles and procedures, or to Centra's hedging practice since the last general rate hearing.

However, Centra did complete International Swaps and Derivatives Association documentation, more commonly referred to as ISDA agreement, with another counterparty in July 2005 bringing the sum total of its financial counterparties to seven (7). Correspondingly, Centra has trained and authorized another individual to enter into derivatives transactions.

MS. MARLA MURPHY: Ms. Stewart, would you please outline Centra's derivative hedging activities since Centra last appeared before the PUB in the '05/'06 and '06/'07 General Rate Application?

MS. LORI STEWART: All of the financial instruments purchased by Centra since last year's General Rate Application were transacted in accordance with the approved derivates hedging policy for primary gas and the associated operating principles and procedures. All hedges purchased were fifty (50) cent out of the money cashless collars. Accordingly, there were no pre-paid premium costs association with the transactions.

During fiscal year 2005/'06, Centra hedged 100 percent of eligible volumes for each month with the exception of the month of April 2005, in which Centra hedged 90 percent of eligible volumes. For all forward-hedged transactions placed since July 2004, Centra has hedged 100 percent of its baseload volumes. Centra made the change to hedging 100 percent of baseload volumes so as to maintain hedge coverage of approximately two-thirds of total normal weather year requirements in the face of different terms in its former and current supply agreements with Nexen.

MS. MARLA MURPHY: Ms. Stewart, would you please describe for the Board the performance of the hedging program in the fiscal year 2005/'06 and in 2006/'07 to-date?

MS. LORI STEWART: Certainly. In fiscal 2005/'06, the Derivatives Hedging Program delivered a 53 percent reduction in the volatility of primary gas rates. Since the inception of the program an annual reduction in the volatility of primary gas rates of between 30 percent and 53 percent has been delivered.

Although market-to-market results are not Centra's measure of performance for the hedging program, customers' gas costs were reduced by $47.5 million in fiscal 2005/'06. Since the inception of the program a net reduction to customers' gas costs of $77.4 million was delivered to the end of fiscal 2005/'06.

In 2006/'07 to-date, the hedging program has delivered a 52 percent reduction in the volatility of primary gas rates to January 31st, 2007, and there has been a realized addition to customers' gas costs of $42.3 million to November 30th, 2006.

MS. MARLA MURPHY: Ms. Stewart, has Centra had any contact with consumer groups since the 2005/'06 and 2006/'07 GRA?

MS. LORI STEWART: Yes, Centra met with the executive directors of the Consumers' Association of Canada and the Manitoba Society of Seniors on two (2) occasions since the last General Rate Hearing.

In December 2005, the meeting agenda included a Fall 2005 natural gas market review, an update on derivates hedging activities and results, and overviews of Centra's retrospective review of hedging, recent PUB orders, and the 2005 Utility Risk Management Summit.

Centra met with Ms. DeSorcy and Ms. Hunter again in April 2006, at which time a similar meeting agenda was accomplished.

MS. MARLA MURPHY: Ms. Stewart, what is Centra's understanding of how the Public Utilities Board should evaluate its hedging transactions?

MS. LORI STEWART: Centra believes that the PUB should evaluate its hedging transactions on the basis of whether they were executed in accordance with its derivatives hedging policy and associated operating principles and procedures which is approved by Manitoba Hydro's Board of Directors as well as the PUB.

MS. MARLA MURPHY: Ms. Stewart, I understand that Manitoba Hydro's internal audit function completed a compliance review of the hedging program in 2006.

Would you please advise the Board as to the conclusions of that audit process?

MS. LORI STEWART: Yes. The compliance review conducted by internal auditors evidenced that the Derivatives Hedging Program was well structured and supported by compliant and appropriate procedures.

Three (3) minor areas for improvement were noted, two (2) of which have already been addressed. And the third, some housekeeping changes to the language of the derivatives hedging operating principles and procedures, will be addressed at such time as changes are sufficient to merit the forwarding of the documents to Centra's Executive Committee for review and approval.

MS. MARLA MURPHY: Mr. Stewart, could you please describe Centra's plans with respect to the hedging program?

MS. LORI STEWART: The parameters of Centra's current hedging program are defined on the basis of customer research. Centra conducted market research on two (2) occasions, in 1998 and in 2004. Research outcomes on both occasions indicated that Centra's customers have variable preferences or risk tolerances for rate volatility. This makes sense given the heterogeneous makeup of Centra's customer base.

However, a couple of general conclusions were clear. Number 1, that customers have some tolerance for rate and bill volatility and, number 2, that tolerance level is relatively small.

General inferences were made that no protection from rate volatility is unacceptable and that Centra should ensure that its actions are consistent with its program objective to mitigate risk on behalf of customers versus undertaking actions that could expand customers' risk profiles.

Given that Centra is hedging on behalf of its customers changes to the parameters of the program should be considerate of customers' preferences and needs. As such, Centra has indicated that it intends to undertake customer research on this topic again in 2008 and to involve consumer groups in that process.

MS. MARLA MURPHY: Thank you, Ms. Stewart.

Mr. Sanderson, would you please outline your areas of responsibility with respect to this Panel.

MR. BRENT SANDERSON: Good morning, Mr. Chairman, Members of the Public Utilities Board, ladies and gentlemen.

In my testimony, I will be providing evidence related to Centra's gas cost for the period from April 1st, 2005 to March 31st, 2006, as well as the related PGVA and other gas cost deferral balances and derivative hedging results for the period from April 1st, 2005 to March 31st, 2006.

I will also be providing evidence with respect to Centra's gas cost forecast for its 2006/'07 fiscal year.

MS. MARLA MURPHY: Mr. Sanderson, one of the approvals that Centra is seeking is final approval of gas cost for the period April 1st, 2005 to March 31st, 2006.

Would you please outline the amounts for which Centra is seeking approval from the Board.

MR. BRENT SANDERSON: Centra is seeking final approval of gas costs in the amount $389.7 million for the period from April 1st, 2005 to March 31st, 2006, as summarized on Schedule 4.0.0 in Centra's application.

As Ms. Stewart outlined in her direct evidence, this includes a reduction in gas cost of approximately $47.5 million as a result of Centra's derivative hedging activity for the 2005/'06 fiscal year.

MS. MARLA MURPHY: Mr. Sanderson, would you please outline the PGVA and other gas cost deferral balances for which Centra is seeking final approval?

MR. BRENT SANDERSON: Centra is requesting final approval of all non-primary gas PGVA and gas cost deferral balances to March 31st, 2006, with carrying costs and the amortization of rate riders to July 31st, 2006, totalling approximately $13.2 million owing to customers.

MS. MARLA MURPHY: Would you please outline the 2006/'07 forecast gas costs for which Centra is seeking final approval?

MR. BRENT SANDERSON: The interim base rates implemented on August 1st, 2006, included forecast gas cost for 2006/'07 based on the forward price strip as of May 1st, 2006. The resulting gas cost forecast for 2006/07 is $482.2 million, as per Schedule 5.2.3(b).

Of the $482.2 million gas costs forecast for 2006/'07, approximately $62.4 million is non-primary gas costs. This amount represents a decrease of approximately $6.6 million from the non-primary gas costs included in existing base rates as shown on updated schedule 5.2.4.

MS. MARLA MURPHY: Thank you, Mr. Sanderson.

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 relating to the 2006/'07 non-primary gas cost allocation study and the allocation of the non-primary gas PGVA and gas cost deferral balances, as at March 31st, 2006.

Additionally, I will be responding to questions related to Centra's requested gas cost approvals and interim primary gas which now also includes the November 1, 2006 primary gas rates approved through

Order 144/06 and rural expansion Orders.

MS. MARLA MURPHY: Ms. Derksen, would you please outline the rate impacts of Centra's application on customers?

MS. KELLY DERKSEN: Centra is not proposing any changes to its rates flowing from this application. Centra is seeking final approval of the rates approved on an interim basis in Order 116/06 and implemented on August the 1st of 2006.

The impacts at that time resulted in an annual bill decrease of 2.8 percent or thirty-nine dollars ($39) for a typical residential customer. When combined with the primary gas application for August 1st, 2006, the annualized bill for a typical residential customer decreased by 7 percent.

The annual bill comparisons were relative to the approved May 1st, 2006 billed rates. The impacts for larger volume customers ranged from decreases of 1.3 percent to 3.7 percent and when combined with the August 1st, 2006 primary gas application, resulted in annualized bill impacts ranging from a decrease of 7 percent to 9.3 percent, dependant on class and usage.

MS. MARLA MURPHY: Ms. Derksen, is the cost allocation -- cost allocation methodology used in connection with this application consistent with that used in previous applications?

MS. KELLY DERKSEN: Yes, Centra is not proposing any changes in its approach to cost allocation in this application.

MS. MARLA MURPHY: And would you please outline the rate riders that Centra implemented on August 1st, 2006?

MS. KELLY DERKSEN: On August 1st, 2006 Centra began refunding approximately $13.2 million in rate riders to customers. The non-primary gas PGVA and gas cost deferral accounts as at March the 31st, 2006, with carrying costs to July 31st of 2006, have been allocated in a similar manner to the method used in the 2006/'07 General Rate Application, the details of which are shown on schedule 7.4.0.

These rate riders implemented on August 1st, 2006, are designed to dispose of the non-primary gas PGVA and gas cost deferral account balances over a twelve (12) month period to expire July 31st, 2007, for all customer classes except the special contract class.

Centra has an agreement with the special contract customer to true up their account annually by issuing a lump sump payment or refund. As such, upon receiving interim approval in Order 116/06, Centra issued a lump sum refund in September of 2006.

Consistent with past treatment Centra has disposed of the supplemental PGVA amount through a rate rider applied to the variable distribution charge for all customers with the exception of the interruptible and mainline classes.

Centra's implemented a separate line item on the bill for both interruptible and mainline customers who receive supplemental gas from Centra, as refunding their portion of the supplemental gas PGVA in their variable distribution charge would result in a negative billed distribution rate.

Additionally, in Order 103/05 the PUB approved a rate delay rider that allowed Centra to implement non-gas cost changes on May 1st of 2006, to coincide with the implementation of Centra's quarterly rate setting mechanism. This rate rider is designed to be disposed of over a fifteen (15) month period also ending July the 31st, 2007, and is currently reflected in billed rates.

MS. MARLA MURPHY: Thank you, Ms. Derksen.

Mr. Chairman, that concludes our direct evidence. If Mr. Peters is okay over there we're -- we're ready to be -- available for cross-examination.

THE CHAIRPERSON: Mr. Peters, why don't

we take our mid-morning break now and then you can start fresh? Thank you. We'll be back in fifteen (15) minutes.

--- Upon resuming at 10:19 a.m.
--- Upon resuming at 10:40 a.m.

THE CHAIRPERSON: At any time you're ready, Mr. Peters.

CROSS-EXAMINATION BY MR. BOB PETERS:

MR. BOB PETERS: Good morning, Mr. Chairman. Good morning to the Panel and my questions are addressed to the Panel and the Panel can determine who is the most appropriate person to answer and even if I direct a question and you think I've directed incorrectly, amongst yourselves I'm sure you'll sort out who should be answering it.

So, Ms. Derksen, last to speak, first to be asked a question. Am I correct from your evidence you're telling the Board that through this hearing Centra is not seeking any changes to any rates presently in place?

MS. KELLY DERKSEN: Correct, Mr. Peters, we are seeking confirmation of rates that were already approved on an interim basis through Order 116/06.

MR. BOB PETERS: And can I suggest you're also asking that not only do you want final approval of the rates in Order 116/06 but you also want final approval of the latest primary gas interim rate that was set for November 1st of '06?

MS. KELLY DERKSEN: Correct. We are seeking final approval of the primary gas rate implemented on an interim ex parte basis on November 1, 2006.

MS. MARLA MURPHY: If I might just clarify for the record, we're also seeking final approval of the -- the other interim orders that are listed in the page 2 of the application -- Tab 2 of the application.

MR. BOB PETERS: Yes, thank you, Ms. Murphy, I'll -- I'll come to that. But suffice it to say, at the end of the day Centra's expectation and request is that the rates presently in place do not change?

MS. KELLY DERKSEN: Correct, sir.

MR. BOB PETERS: That does also recognize, does it, Ms. Derksen and Mr. Warden, that should the Board, in the course of this hearing, determine that some of the costs that are presently in the rates that are presently in place on an interim basis, if those costs are determined to be inappropriate or not properly calculated the Board may make changes as a result of this process?

MR. VINCE WARDEN: Agreed.

MR. BOB PETERS: Now, in the Chairman's opening comments he mentioned various rates that comprise the consumers' bill. And in terms of a brief review of those, primary gas is the -- is the largest rate component of a consumer's bill; have I got that right?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: Ms. Derksen, primary gas is all the gas that Centra sources from western Canadian supplies?

MS. KELLY DERKSEN: Yes, it's solely the molecules of gas, sir.

MR. BOB PETERS: And when we say the molecules of gas sourced from western Canadian supplies are we really saying Alberta-supplied or are we also talking about maybe BC, Saskatchewan, or even Manitoba?

MR. BRENT SANDERSON: If I might just jump in here and help out for a second, it's gas that we take delivery of in Alberta where the actual physical origination point of that gas, be it across the Alberta/BC border and in BC producing range, we have no way of know that; it's -- it's take -- deliver -- it's --

we take delivery at a delivery point in Alberta.

MR. BOB PETERS: And the delivery point in Alberta is what, Mr. Sanderson?

MR. BRENT SANDERSON: Empress.

MR. BOB PETERS: And Empress is located near the Saskatchewan/Alberta border?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: And in the primary gas that you source, Centra estimates that that is approximately 98 percent of the overall supply of gas?

MS. KELLY DERKSEN: In a normal year that's approximately correct. Currently we have embedded in the consumer's bill 100 percent which is reflecting actual conditions to-date and in fact we are forecasting for this upcoming gas year which runs from November 1 to October 31 that that represents -- that primary gas represents 100 percent of the anticipated supply.

MR. BOB PETERS: Well, that's interesting, Ms. Derksen. Does that suggest to the Board that Centra will not be needing supplemental gas supplies?

MR. BRENT SANDERSON: As a result of the significant conservation that Manitobans have demonstrated since last year, when we look out at a normal weather year now, our normalized Manitoba load has dropped to such a point that we now forecast being able to serve 100 percent of customers' commodity requirements in a normal year with primary gas.

We would have, in a subsequent forecast, a small amount of supplemental gas reflected in the forecast but in a normal weather year it would be an immaterial amount.

So we would still require a supplemental rate to collect that small amount of cost, but when you look at the billing percentages, the -- the amount in the forecast is so immaterial with respect to supplemental supplies that we would be billing customers at a hundred (100) and zero (0) primary and supplemental at the outset of a -- of a typical year looking forward.

MS. KELLY DERKSEN: I might clarify, Mr. Peters, that the application before the Board currently contemplates the use of supplemental gas and reflects the costs as a result of that forecast. And so what I was referring to is on a -- on a go-forward basis as opposed to the application that's currently before the PUB.

MR. BOB PETERS: All right. Just so the Board then is clear, you're asking the Board to approve not only some primary costs that have been incurred but also, forecasting ahead, you want the Board to approve the -- the supplemental gas costs, and you base that on what would have been a -- perhaps a normal year from years gone by but not going forward.

MS. KELLY DERKSEN: True. That's correct. We are seeking approval of supplemental gas costs that were forecasted when we made application on June the 16th, and that was based on a May 1st forward price curve.

MR. BOB PETERS: Okay. I'll come back to that when we talk about supplemental gas. But in terms of the primary gas rates, it was mentioned in the direct evidence that those rates are set on a quarterly basis through the rate-setting methodology?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And there's no changes to the primary gas rates that are in place right now being sought, you've told us, you're content with the November 1st primary gas rates.

MS. KELLY DERKSEN: We are, sir. Yes.

MR. BOB PETERS: And there's no changes being sought to the rate-setting methodology, is there, Ms. Derksen?

MS. KELLY DERKSEN: There is not, sir. No.

MR. BOB PETERS: And as Ms. Murphy corrected us, there's approximately seven (7), and we'll come to those, interim primary gas orders that are -- that are the subject of a request to finalize.

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And am I correct that the primary gas portion of Centra's cost of gas is also the subject of Centra's derivative hedging program?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And so in this hearing Centra is asking the Board to approve the prior primary gas rates which include an amount on account of Centra's hedging efforts.

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And in the -- I believe it was Ms. Stewart's direct evidence, echoed to some extent by Mr. Sanderson, those hedging impacts have, on a aggregate basis for 2005/'06, resulted in gas costs that are lower than what they would otherwise have been had there been no hedging.

MS. KELLY DERKSEN: Yes, sir. That's correct.

MR. BOB PETERS: And that may have been in the aggregate but on an individual month-by-month basis there are circumstances where Centra's hedging program has added to the gas costs that consumers are being asked to pay.

MS. LORI STEWART: I don't believe that's correct for the 2005/'06 fiscal period.

MR. BOB PETERS: I don't want to argue with you this early, Ms. Stewart, but if I turn to -- and, Mr. Chairman and Board Members, it is -- it is only for convenience, not an expectation or a suggestion, that five (5) binders of material can be reduced to twenty-eight (28) little tabs in a book of documents.

But for convenience of the Board Members and the witnesses, on Tab 8 of a book of documents that I have selected, I'd just like to draw Ms. Stewart's attention to Schedule 4.2.0 and look at the final settled results.

And I believe, Ms. Stewart, those are for fiscal '05/'06; is that correct?

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

MR. BOB PETERS: And if you look at the months of February '06 and March of '06, you'd agree with me that Centra's hedging efforts have increased the cost of gas than what would have been the case had there been no hedging?

MS. KELLY DERKSEN: Yes, Mr. Peters.

MR. BOB PETERS: In terms of primary gas, consumers can choose to buy their primary gas from Centra which we would call, in these hearings, system supplied gas or consumers can choose to buy from a natural gas broker, such as Municipal or Direct Energy, as well as, Energy Savings Manitoba Corp; would that be correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And does Centra hedge the volumes of natural gas that the brokers sell to Manitoba consumers?

MS. LORI STEWART: No, we do not.

MR. BOB PETERS: And why is that Ms. Stewart?

MS. LORI STEWART: Because those customers have an arrangement with a marketer in terms of the price of their natural gas.

MR. BOB PETERS: And so the pricing o the primary gas that brokers supply to consumers is a matter strictly between the brokers and the consumers, is that correct?

MS. LORI STEWART: Yes, based on the contractual agreement between those two (2) parties.

MR. BOB PETERS: And it may be that Centra will include on the bill, the monthly bill to the consumer, the primary gas supplied by the broker at a price that Centra is asked to reflect on the bill?

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

MR. BOB PETERS: All right. Moving from primary gas, just to review then, the second of the perhaps five (5) rate components in Manitoba, would be supplemental gas, correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: Am I to hear -- or to read into your previous comments, Ms. Derksen, that perhaps in future years we won't need any supplemental gas?

MS. KELLY DERKSEN: I'm not sure that I would go that far, Mr. Peters. We have had one (1) year of experience with respect to the current environment that we're in, which I'm suggesting that customer conservation has been much more significant than we have seen in the past.

We don't know if that's permanent and so for the year that we are currently in, the gas year that we are currently in, we are forecasting that, but we can't go beyond that.

MR. BOB PETERS: Can you tell the Board what -- how you quantify that conservation that you've -- that you've recognized?

MR. BRENT SANDERSON: Well, the conservation would be characterized by looking at the actual consumption that was evidenced in the market over a period of time historically. And that would be actual consumption.

And then our load forecasting people would undertake a mathematical process to normalize that consumption for differences in weather relative to forecast and embedded heating values in the gas and other factors.

And after normalizing for all of these non-normal factors relative to the forecast, you're left with the difference between what customers actually used on a normalized basis and what would have been forecast to have been used, and that difference is attributed to conservation.

MR. BOB PETERS: When you say "conservation," is Centra able to be more specific to the Board? Is that people turning their thermostat down, or is it that they've done -- maybe putting on a sweater? Or is it better insulation for the home, or do you have any idea?

MR. BRENT SANDERSON: All of those items, Ms. Derksen made a good point, in that one (1) year does not a long run future make. And it's impossible at this point, to specifically attribute overall conservation to each particular element that might have driven that conservation.

And so that's a big outstanding question as to how much of that conservation was driven by permanent changes, if you will, replacement of low efficient furnaces with higher efficiency appliances.

And how much would have been the result of, for example, just people being willing to put on a sweater and turn the thermostat down. And so there's -- there's going to be an element of permanent conservation in there and then behavioural -- behavioural changes, which are a little bit more fluid.

And so it will take a number of years out into the future for our load forecasting people to analyse and model that conservation to separate out those difficult elements that are attributable to each of the different components of conservation.

But, at the end of the day, it will all be an estimate in and of itself, as there's no way to exactly determine what unit of volume of conservation is attributed to what individual factor.

MR. BOB PETERS: Mr. Stephens, maybe just to get your brief input at this point in time, if into the future, it appears that supplemental gas is not required for Manitoba; that will cause you to have to make some changes to the portfolio of assets that you manage for the Corporation.

MR. HOWARD STEPHENS: Certainly.

MR. BOB PETERS: And presently, Mr. Stephens, the supplemental gas to which I'm referring is 100 percent sourced in the United States; would that be true?

MR. HOWARD STEPHENS: Not necessarily. We can buy delivered service which would be also categorized as supplemental gas from Alberta.

MR. BOB PETERS: Other than delivered service then the balance of your supplemental gas is arranged through --

MR. HOWARD STEPHENS: What we traditionally refer to in terms of the supplemental gas is the gas we buy on the ANR southeast and southwest transport capacity.

MR. BOB PETERS: And the ability for Centra to meet the Manitoba load with just primary gas hasn't happened with any changes to the portfolio that you manage for the Corporation?

MR. HOWARD STEPHENS: No, our portfolio hasn't changed, the load has shrunk underneath it.

MR. BOB PETERS: And it was usually the case, was it not, that the supplemental gas was needed in Manitoba when the weather turned cold and you weren't able to meet it with primary gas supply?

MR. HOWARD STEPHENS: Typically, yes.

MR. BOB PETERS: And in terms of a usual percentage, I'm not sure there is such a thing anymore now, but maybe Mr. Sanderson or Ms. Derksen can tell us what would have been a -- a usual percentage of supplemental gas provided to Manitoba load?

MS. KELLY DERKSEN: Mr. Peters, in the last number of years it's fluctuated and for firm customers it's fluctuated anywhere from 6 percent to 0 percent, so that gives you a -- a range of what we've seen in the last number of years.

MR. BOB PETERS: All right and --

MR. BRENT SANDERSON: And -- and also if it's all right, Mr. Peters, just to add one (1) item of clarification. When we talk about looking out and not expecting to need a material amount of supplemental gas, that assumes normal weather conditions.

Now, it's been a number of years since we've had a very cold winter and the conservation that we're discussing here would not eliminate the need for what we now call supplemental supplies in the event that weather would be colder than normal.

THE CHAIRPERSON: Mr. Hoaken, you will note that we don't consider today cold.

MR. ERIC HOAKEN: Duly noted.

MR. HOWARD STEPHENS: No, this is a balmy day as a matter of fact.

Mr. Peters, just to add to that, there is the potential where we could have a normal winter but still have to buy some supplemental gas because if we have design day, even though it's a very warm year, an unusual set of circumstances admittedly, we would have -- potentially have to buy some supplemental gas in the form of -- and I mean provided it in the form of alternate service to our interruptible customers if it was a cost effective way to help them stay on gas.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: All right. Thank you for that. And I just do want to clarify a point hopefully for the benefit of the newest Board member.

Ms. Derksen, you referenced firm supply in an answer to me previously given and the firm -- sorry, the firm customers -- the firm customers that you have, have received supplemental gas anywhere from 0 percent to 6; have I got that right?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And you said, "firm customers" because you were trying to differentiate from interruptible customers; would that be correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: Can you just briefly tell the Board what you mean by, "interruptible customers"?

MS. KELLY DERKSEN: We have a service available to certain customers who elect to choose it under a certain set of circumstances such that those customers electing that service would take the service under arrangement whereby they may be curtailed at any point in time during the year and the -- the tradeoff for that customer for course is that they're -- they are charged lesser rates particularly related to the distribution side of our system.

MR. BOB PETERS: And, Ms. Stewart, the supplemental -- supplementary -- supplemental gas costs that we're talking about, are those gas costs hedged by Centra?

MS. LORI STEWART: No, they are not.

MR. BOB PETERS: They could be but you choose not to; would that be correct?

MR. HOWARD STEPHENS: No, sir, we couldn't hedge those volumes because I don't know necessarily when we're going to -- going to take them or where we're going to take them from so for us to put a hedge on them would be perfunctory on our part.

MR. BOB PETERS: Well, that -- okay, let me rephrase the question then, Mr. Stewart -- Mr. Stephens. The -- there is an ability to hedge supplemental gas because it's priced on an IMEX exchange?

MR. HOWARD STEPHENS: Oh, certainly, if you have a pre-determined need for it and you know when you're going to take it, how much you're going to take, and from where you're going to take it, you can certainly hedge it.

MR. BOB PETERS: And what you're telling the Board is that Centra does not hedge the supplemental gas that comes to Manitoba because in any given winter, you are not 100 percent certain that you will need that gas?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And if you were to hedge gas that you weren't confident, to a very high percentage, that you will need, the Corporation would consider that speculative?

MR. HOWARD STEPHENS: That would fall under our definition of speculation, yes.

MR. BOB PETERS: And the Corporation does not speculate?

MR. HOWARD STEPHENS: Not in any case, no sir.

MR. BOB PETERS: Mr. Stephens, one of the -- the next rate component in Manitoba, the third of five, is the transportation to Centra costs, is that correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And those are the rates for transport -- transportation to recover exactly that, transportation costs from Western Canada to Manitoba, as well as, for some storage forecast gas in the summer months and for re-delivery to Manitoba, when there's high consumption months from the States?

MR. HOWARD STEPHENS: And that also includes the US pipelines that I referred to. I only mentioned two (2), there's another couple of lengths of pipe that we have contracts for, but I mean it encompasses all of that transportation.

MR. BOB PETERS: All right. And the rates for transportation, you were telling us in your direct evidence, those are set by another regulator and that's the National Energy Board, that is the western Canadian transportation rates?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And because that -- that comes to Manitoba on the TransCanada pipeline?

MR. HOWARD STEPHENS: That's correct.

They regulate all of TransCanada Pipeline's rates or tolls.

MR. BOB PETERS: In terms of the transportation costs in the United States, as I understand what you've now told the Board, it includes not only the storage in Northern Michigan, but also all the pipeline costs to get gas to and from Michigan?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And who sets those rates, Mr. Stephens?

MR. HOWARD STEPHENS: The FERC, or the Federal Energy Regulatory Commission.

MR. BOB PETERS: Thank you. The fourth of five rate components to a Manitoba customer's bill is the distribution rate, is that correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And the distribution rate, Ms. Derksen, recovers the costs associated with Centra owning and operating a gas utility?

MS. KELLY DERKSEN: Yes, sir and I'll add what we say on a very frequent basis in this application is the piece that is -- we are seeking approval of, only relates to -- well two (2) pieces, unaccounted for gas number 1 and, secondly, Minell pipeline.

MR. BOB PETERS: So in the distribution

rates that the Corporation charges, there are a number of components that you're telling us and for most of the operating expenses and finance and depreciation cost and the like; those are included in distribution rates but those are not the subject of this hearing?

MS. KELLY DERKSEN: I think I'll just clarify that. The bulk of our distribution type costs, O&M, taxes, depreciation, and so forth are indeed recovered through the distribution rate.

There are some of those costs, though, that find themselves embedded in the other rates that we spoke of this morning. I just wanted to make that point of clarification.

And indeed, we are not seeking changes to those pieces of the rate that are embedded throughout the rates, including the distribution.

MR. BOB PETERS: And the aspects of the distribution rate that you have obtained interim Board approval to change, relates to the unaccounted for portion of gas together with the operating expenses for the Minell pipeline?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And can you briefly explain what unaccounted for gas is?

MS. KELLY DERKSEN: Reminiscent of a

hearing a couple of years ago, unaccounted for gas is basically the difference between the gas that comes onto the Centra system and the gas that then gets used by the customer and flows ultimately through their metre.

Those two (2) numbers never equate and so for a number of reasons there is gas that we lose on the system and it could be for a number of reasons including the fact that our metres are not 100 percent precises.

MR. BOB PETERS: And there's other reasons too that you have unaccounted for gas, Ms. Derksen, that would be things like pipes breaking and gas escaping to the atmosphere, as an example?

MS. KELLY DERKSEN: Yes, there are a number of reasons, Mr. Peters.

MR. BOB PETERS: Now, the Minell pipeline costs, Mr. Stephens, can you tell the Board what is the Minell pipeline or where is it?

MR. HOWARD STEPHENS: The Minell pipeline is the line that we use to serve Dauphin and its origination is just inside the Saskatchewan border at Moosomin and we run the line up north to Russell and then east to Dauphin, and we treat it as a pipeline because it is moved across a provincial boundary and as a result is under FERC -- not FERC, NEB jurisdiction. The FERC can have it if they want.

MR. BOB PETERS: Why are those costs included in distribution rates rather than in transportation rates?

MS. KELLY DERKSEN: Mr. Peters, it stems back to a number of years that we have been structuring our rates in that way and I think it really has to do with the fact that we view that cost very similar to the cost of owning and maintaining our own pipeline system.

And I think that's why the Company, ultimately, decided and the Board ultimately agreed that we would recover those costs in our distribution rate.

MR. BOB PETERS: And because you can recover those costs in your distribution rate they are paid for by all customers on Centra's system, which includes system-supplied customers and broker-supplied customers.

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

MR. BOB PETERS: And just before I leave it, those other aspects of distribution rates that are not presently before the Board which you included -- which you indicated, Ms. Derksen, would include operating and maintenance taxes, depreciation, amortization, those are matters that are generally the subject of a General Rate Application.

Would you agree with that?

MS. KELLY DERKSEN: I do, yes.

MR. BOB PETERS: And if I heard correctly this morning, Mr. Warden is providing some more work for you to do because I think I heard him say early in the new year there's an expectation the Corporation will file for a General Rate Application for Centra.

MS. KELLY DERKSEN: There's no shortage of work in my area, sir, no.

MR. BOB PETERS: Now, the last of the five (5) rate components that we think of in Manitoba is the basic monthly charge; is that right?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: Am I correct that the basic monthly charge serves to recover a portion of the operating costs such as the meter reading and billing functions?

MS. KELLY DERKSEN: Yes. Those costs that we deem from a cost allocation perspective to be customer related.

MR. BOB PETERS: And we'll talk about them a little later in these proceedings, Ms. Derksen, but the -- not all customer classes recover the same percentage of those costs.

Would you agree with that?

MS. KELLY DERKSEN: We recover 100

percent of the costs -- of the customer-related costs from all customers in all rate classes, but the rate design aspect is -- is the issue that I think that you're referring to.

And what I am suggesting is that for the small-volume customers, those being in the SGS or the small general service class as well as the large general service class, the rate design is such that we only -- we only recover a portion of those customer-type costs in the basic monthly charge.

What is remaining, therefore, then gets recovered through the distribution charge.

MR. BOB PETERS: All right. So I should have said that the basic monthly charge for residential customers recovers a different percentage of those costs than the basic monthly charge does for other classes of customers?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: All right. With that primer perhaps if the witnesses and the Board could turn with me to Tab 2 of the book of documents that's been circulated, there's a copy of Schedule 5.2.4.

(BRIEF PAUSE)

MR. BOB PETERS: You have that, Ms. Derksen?

MS. KELLY DERKSEN: Yes, I do.

MR. BOB PETERS: And on Schedule 5.2.4 found at Tab 2 of the book of documents we see different -- different components of the bill of rates and we see different amounts for different years.

Am I correct that the primary gas line 1 item that you're showing in the second column, that is recoverable at existing rates, that primary gas rate that was used to calculate that number was based on rates that came into effect on May the 1st?

(BRIEF PAUSE)

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

MR. BOB PETERS: And since May 1st you've already had two (2) other quarterly primary gas rate adjustments. I think you've told the Board both of them have been decreases, that being on August 1st and also on November 1st?

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: And in terms of the supplemental gas that we've talked about, you're telling the Board that in column 2, if the rates remained as they did before your interim application that gave rise to Order 116/06, your rates would have recovered $9.88 million?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: And you're telling the Board in this application in column 1 that your forecast is for the -- for the current fiscal year you only need $9.5 million?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: And likewise for transportation existing rates would recover $52.9 million and your forecast is you only need $45.9 million.

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

MR. BOB PETERS: Is the distribution component on this schedule related to the unaccounted for gas as well as Minell?

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

MR. BOB PETERS: And here again there's an increase being sought as opposed to a decrease in the other rate components; have I got that right?

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

MR. BOB PETERS: But collectively on line 8 the non-primary gas cost, which include supplemental transportation and distribution, are forecast at $62.4 million and that's approximately $6.6 million lower than what is currently embedded in the rates before the Board granted interim approval in Order 116/06?

MR. BRENT SANDERSON: No, that would have been -- could you repeat the question, please?

MR. BOB PETERS: Let me ask it a different way. Prior to the Board's Order 116/06 the non-primary gas costs that would be recovered from existing rates would have been approximately $68.9 million?

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

MR. BOB PETERS: And then in your interim application that you made and that you're seeking to finalize in this proceeding, you're only asking for $62.4 million of non-primary gas costs?

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

MR. BOB PETERS: And that's the source of the $6.6 million reduction that you referred to in your evidence?

MR. BRENT SANDERSON: Yes.

(BRIEF PAUSE)

MR. BOB PETERS: Can you enlighten the Board briefly as to why the distribution component of rates will go up eight hundred and thirty-seven thousand dollars ($837,000) whereas the supplemental gas and the transportation components will be going down?

MR. BRENT SANDERSON: I will need to refer to the application if you'll just give me one (1) moment, please?

(BRIEF PAUSE)

MR. BRENT SANDERSON: I would have to undertake to quantify and explain that difference to you. My initial assumption is it has to do with increases in the unit cost of commodity relative to what was embedded in the prior year's distribution rates for unaccounted-for gas, but I would have to undertake to go verify that.

--- UNDERTAKING NO. 1: For Mr. Sanderson to explain as to why the distribution component of rates will go up eight hundred and thirty-seven thousand dollars

($837,000) whereas the
supplemental gas and the
transportation components
will be going down.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Do you recall if the percentage of unaccounted-for gas is changing in this application?

MR. BRENT SANDERSON: No. In this application the percentage we've allocated to -- our assumption for unaccounted-for is -- remains the same.

MR. BOB PETERS: The same as it did in -- in the prior rates.

MR. BRENT SANDERSON: Correct. Which is what leads me to believe that it has to do with the increases in the unit cost of the commodity from one year to the other.

MR. BOB PETERS: And I know we have it somewhere in the materials, but was that .9 percent or was it 1.0 percent?

MR. BRENT SANDERSON: 0.9 percent.

MR. BOB PETERS: Thank you. So what you're telling the Board is that when Ms. Derksen says you have to balance what you deliver to consumers with what you buy, you, in essence, are buying 0.9 percent more gas than consumers' meters are showing because somewhere along the way there's unaccounted-for gas?

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

MR. BOB PETERS: And now that we've seen where the $ 6.6 million reduction comes from the forecast non-primary gas cost rates, the other major rate adjustment in Order 116/06 came by way of a refund of $13.2 million from various non-primary gas PGVA's and deferral accounts?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And those deferral account balances were to the end of your fiscal year as at March 31, 2006?

MS. KELLY DERKSEN: Yes. And they're carried through to July 31st, 2006, which means that we've added carrying costs and netted against any collections or refunds that were occurring between April to -- April 1st, 2006 and July 31st, 2006 as well.

MR. BOB PETERS: I'm sorry, I didn't understand that last component. You have -- you have your balances at of March 31, '06 and you are adding an interest or a carrying cost component to take it to July 31st, '06, which was just before the Board granted interim rates in Order 166/06.

Correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And in those months from March 31, '06 to July 31, '06 you netted that against certain collections.

Can you just explain that?

MR. BRENT SANDERSON: What Ms. Derksen is referring to is we established an account effective July 31st, 2005, which was an accumulation of all prior period gas cost deferrals from prior periods. And during the period from August 1st, 2005 to July 31st, 2006 we were refunding customers those amounts, the specific amounts which I'll have to leave to Ms. Derksen if you'd like to get into the specifics of that.

So our -- this $13 million and change that we're talking about here reflects the fact that we continued to refund those amounts from the period April 1st, 2006 to July 31st, 2006, that is all factored and considered in that net balance.

MR. BOB PETERS: Would it be fair to characterize the $13.2 million as -- as the net result of -- of forecasting errors last time you were before the Board in looking for supplemental gas transportation and distribution for UFG costs?

MS. KELLY DERKSEN: Not to suggest that we've -- we've erred in what we've done, but to the extent that we can never predict where prices are going to go or what weather is going to do, which are both factors in our determinations, to the extent that they're never exactly what we forecast, yes, I would agree with that statement.

MR. BOB PETERS: I didn't mean it disparagingly, Ms. Derksen, but -- and we've heard -- we've heard Mr. Stephens tell you that the National Energy Board rolled back some tolls on TCPL, and those are examples of things that weren't included in the last forecast.

Would that be fair?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And would it also be fair that this $13.2 million that you're refunding has been paid for by Manitoba consumers, so, they're just getting their money back

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: Getting their money back with interest?

MS. KELLY DERKSEN: With interest, yes.

MR. BOB PETERS: And the Manitoba consumers who are getting their money back with interest include system supplied customers, as well as, broker supplied customers?

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

MR. BOB PETERS: And that's correct because the broker supplied customers, also pay supplemental gas rates, transportation rates and distribution rates?

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

(BRIEF PAUSE)

MR. BOB PETERS: All right. With that assistance, I think if we turn to Tab 1 of the book of documents, we can now frame the application, I hope, succinctly.

In Tab 1, you will see reproduced extracts from Tab 2 of the application, pages 1 to 4. Have you located that?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And when you ask in 1(a) of the application for final approval of supplemental gas, what you're asking for final approval of, is the number that's contained in tab 2 of the book of documents, and that's the $9.497 million?

(BRIEF PAUSE)

MS. KELLY DERKSEN: Mr. Peters, we are seeking final approval of the rate and not the costs that underlies that rate.

MR. BOB PETERS: All right. But, the costs that underlie the rate that the Board approved was the $9.497 million, would you agree with that?

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

MR. BOB PETERS: And would you agree that the cost that underlies and supports the transportation rate, is the $45.927 million found on schedule 5.2.4?

MS. KELLY DERKSEN: Yes, I agree that that is the cost that underlies the rate.

MR. BOB PETERS: And for the distribution it will follow then that the cost that underlies the interim approved distribution rate, that's presently in effect, is the $6.927 million?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: In aggregate, that's the $62.352 million shown on schedule 5.2.4 for non-primary gas costs?

MS. KELLY DERKSEN: That is the forecast, yes.

MR. BOB PETERS: From what you told the Board earlier, you know you're going to be wrong, you just don't know how much you're going to be wrong, would that be true?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And to make it fair to consumers and the Corporation, you have in place various purchase gas, variance accounts and deferral accounts so that you can track any deviations from what's forecast?

MS. KELLY DERKSEN: Yes, we do.

MR. BOB PETERS: On item B of the application found at Tab 1 of the book of documents, the final approval of gas costs from April '05 to March 31, '06 is the $389.7 million that I think the panel has already spoken to this morning.

And those represent final costs which include all gas components, including primary gas?

MS. KELLY DERKSEN: Yes, for the fiscal 2005/06 period.

MR. BOB PETERS: In number C, when you ask for the approval of the reduction in primary -- non-primary gas base rates of $6.6 million, that has already been addressed by way of the cost that under support the supplemental transportation and distribution costs that we've already talked about. That's not a new item, is it?

MS. KELLY DERKSEN: It's not a new item, you're right, sir.

MR. BOB PETERS: Yes. And in terms of the final approval of the balances and the disposition of the PGVA's and the deferral accounts of $13.2 million, that lead to a rate rider being added to the rates that the Board approved on an interim basis in Order 116 of '06.

MS. KELLY DERKSEN: Yes and I would suggest that it too is reflected in part A, above.

MR. BOB PETERS: And it's reflected in part A because the Board approved an interim rate and the rate the Board approved was a billed rate, as well as a base rate, and the billed rate had the rate rider attached to it?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: Okay. Then turning to item E of the application final approval of supplement gas, transportation to Centra, and distribution to customers, sales rates effective November 1, 2004, which were approved on an interim basis in -- in past Board orders, that represents the prior year's forecast from which there has been additional funds collected in the PGVAs that we've talked about?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And then in terms of number "F", a final approval of supplemental gas, transportation to Centra, and distribution to customers effective August 1st of '05 which were approved, those rates also contributed to the surplus that's in the PGVAs in the deferral accounts; would that be -- would that be true?

MS. KELLY DERKSEN: Yes, that is true.

MR. BOB PETERS: And Item number "G" - Ms. Murphy will be glad to know we haven't forgotten it - it's the interim approval of primary gas sales rates that the Board has given since the last time the primary gas quarterly rates were -- were sought to be approved.

MS. KELLY DERKSEN: Yes, and I added in my evidence-in-chief this morning that we are including November 1 to that list and that could be identified in Part "I" below.

MR. BOB PETERS: And that would be, just for the record, Order 144/06 to which you're referring, Ms. Derksen?

MS. KELLY DERKSEN: Yes, I am referring to that.

MR. BOB PETERS: Now, maybe we can deal with this right here and right now.

In the primary gas rates that the Board sets there are hedging impacts imbedded in those rates; is that correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And some of those hedging impacts in some of those orders are settled and some of those hedging impacts in those interim orders have not yet settled; would that be true?

MS. KELLY DERKSEN: That's true, yes.

MR. BOB PETERS: Whether or not those hedging impacts have crystallized or settled, the Corporation is still asking for final approval of the interim primary gas rates?

MS. KELLY DERKSEN: Yes. Again, we are seeking approval of the rates as opposed to the underlying cost that drives those rates because, indeed, as you have specified, they have as -- because of a number of reasons, and hedging impacts is just one (1) of them, that because they had not yet settled we are only seeking final approval of the rate at this time.

MR. BOB PETERS: And to the -- to the extent that those costs are different in actual terms from what they are in those interim orders, those costs will flow into a PGVA or a deferral account; is that true?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: So if the Board does grant interim -- does grant final approval of those interim quarterly orders, the Corporation acknowledges that there may be subsequent adjustments to the PGVA accounts of the Corporation to reflect costs that the Board determines to be final?

MS. KELLY DERKSEN: Agreed, sir. We recognize the fact that the Board will have the opportunity and the public for -- for that fact as well will have an opportunity to review them at a later time.

"Them" I mean the PGVA accounts and the costs that ultimately flow into that PGVA account and if the Board determines at a later time that either we have incurred those costs prudently or we have not, the Board will have an opportunity to adjust rates, ultimately, as a result of those decisions at a later time.

MR. BOB PETERS: And, Ms. Derksen, the reason you're bringing those interim primary gas quarterly rates to the Board for finalization now is because when you got those orders from the Board, it was pursuant to an interim ex parte application by the Corporation, correct?

MS. KELLY DERKSEN: Yes, and this is the first opportunity that both the Public Utilities Board and interested stakeholders and the public at large have had an opportunity publicly to -- to look at that information.

MR. BOB PETERS: Thank you. And just to crystallize one (1) point that you made, if the Board were to disallow a cost, for whatever reason, you're suggesting that that cost adjustment can be made in the PGVA account rather than not finalizing interim rates?

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

MR. BOB PETERS: And -- and when you say you agree, that's also the position of Centra, correct?

MS. KELLY DERKSEN: I'm here on behalf of Centra, yes.

MR. BOB PETERS: I appreciate that. Thank you.

Would you agree that that's somewhat evolved thinking from what has previously been before the Board, where if there were unsettled positions those primary gas rates usually weren't finalized?

MS. KELLY DERKSEN: It must have been -- if that was the case, it must have been prior to a few years ago because in the last couple of years, that I am aware, that we have indeed sought final approval of rates that -- to which the underlying costs have not yet settled.

MR. BOB PETERS: All right. And the -- point H of the application talks about final approval of interim orders related to amended or new franchise agreements and their underlying feasibility tests for the rural municipalities of Rockwood, Ste. Anne and North Cypress; correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And has -- have we now covered anything else -- everything else or is there something to be added to the final point, other than, as we've already mentioned, Order 144/06?

MS. KELLY DERKSEN: 144/06 is the only order that has been issued subsequent to us filing this application and it's the only subsequent order that we are seeking final approval of now.

MR. BOB PETERS: All right. Ms. Derksen, while you are on the microphone, in Tab 8 of the -- of the application you have filed some responses to various Board directives and some past information.

Would that be correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And am I correct in suggesting that Centra is not seeking approval from the Board for any of those aspects at this time?

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, maybe I can rephrase that question.

You're not seeking any approval related to the salt cavern storage report that you have.

Would that be correct?

MS. KELLY DERKSEN: Correct.

MR. BOB PETERS: Are you seeking any approvals related to changes in the Western Transportation Service?

MS. KELLY DERKSEN: No, sir.

MR. BOB PETERS: Are you seeking any approvals in this Hearing related to the long-term gas supply?

MS. KELLY DERKSEN: No, sir.

MR. BOB PETERS: Are you seeking any approvals in this Hearing for any changes to the hedging policy and procedures?

MS. KELLY DERKSEN: No.

MR. BOB PETERS: Are you seeking in this Hearing any approval for any changes to the broker-related costs?

MS. KELLY DERKSEN: No.

MR. BOB PETERS: And in this proceeding,

Ms. Derksen, are you seeking -- excuse me -- are you seeking any approval for any changes to the basic monthly charge?

MS. KELLY DERKSEN: We are not, no.

MR. BOB PETERS: And with respect to the financial statements that Mr. Warden introduced, there are no approvals being sought relative to that, would that be correct?

MS. KELLY DERKSEN: That's correct.

MR. BOB PETERS: And there's no request in this application before the Board to change any of the customer class classifications.

Is that correct?

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

MR. BOB PETERS: Mr. Warden, I could check my notes, I'm not sure you said it, but did you tell the Board what the time line was expected for the General Rate Application that -- that Centra was going to file with the Board?

MR. VINCE WARDEN: I didn't specify a date. We do expect to file mid to late January of '07.

MR. BOB PETERS: Would it be the Corporation's request for rates to be in effect for April the 1st, 2007?

MR. VINCE WARDEN: No. May the 1st of

2007 would be the first proposed rate increase.

MR. BOB PETERS: And the request -- I'll just give you a second.

(BRIEF PAUSE)

MR. VINCE WARDEN: Thank you. We're fine.

MR. BOB PETERS: I'm not sure I am. But -- I'll rephrase the question. What you're telling the Board is early in the new year you're going to be filing a General Rate Application seeking to change the distribution rates.

You've suggested to the Board, if I heard correctly and my notes are right, that it would be 1 percent for the first test year and -- I'm sorry, 2 percent for the first test year and 1 percent for the second test year?

MR. VINCE WARDEN: Correct.

MR. BOB PETERS: And you would ask for those rates for the first test year which would be the '07/'08 fiscal year of the Corporation to go into effect on May the 1st?

MR. VINCE WARDEN: Correct.

MR. BOB PETERS: And May the 1st because

that coincides with a primary gas rate adjustment?

MR. VINCE WARDEN: That's right.

MR. BOB PETERS: I'm not sure the level of detail that you have of that application, Mr. Warden, but are you foregoing one (1) month's revenue in the new fiscal year from new rates or is there a request to recover that through a rate recovery rider of some kind that Ms. Derksen will develop?

MR. VINCE WARDEN: The rates would be effective May the 1st, so we would not expect any revenue increase to be effective April the 1st of that fiscal year.

MR. BOB PETERS: You'd seek to recover whatever increase you were awarded, if any, over the eleven (11) months, not over twelve (12) months?

MR. VINCE WARDEN: Yes.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Warden, and again I may have incorrectly posed a question, where the rate increases that you are suggesting will form the basis of your GRA application, it's an average 2 percent increase in total revenues for fiscal '07/'08, have I got that right?

MR. VINCE WARDEN: You do, yes.

MR. BOB PETERS: And it's not just a 2 percent increase in the distribution portion of the rates, it's in -- of overall revenue?

MR. VINCE WARDEN: Overall revenue, correct.

MR. BOB PETERS: And likewise the 1 percent for the '08/'09 fiscal year would be again an average rate increase?

MR. VINCE WARDEN: Yes.

MR. BOB PETERS: All right. Thank you.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Stephens, in terms of gas supply storage and transportation contracts, Centra currently buys its primary gas from one (1) supplier, is that correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And who is that?

MR. HOWARD STEPHENS: Nexen Marketing.

MR. BOB PETERS: And for how long have you purchased from Nexen?

MR. HOWARD STEPHENS: You're testing my memory, I'm going to say four (4) years.

MR. BOB PETERS: And that contract with Nexen to supply Centra's primary gas expires October 31 of '07?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: You'd mentioned in your opening comments to Ms. Murphy that unless mutually agreed, it will expire October 31, '07?

MR. HOWARD STEPHENS: There is language in the contract that allows for us, if upon a mutual agreement, to extend the contract.

MR. BOB PETERS: Is there a date by which that mutual agreement must be confirmed?

MR. HOWARD STEPHENS: I believe we have to give them six (6) months notice.

MR. BOB PETERS: And has there been any indication to date as to whether Nexen is amenable to extending the agreement?

MR. HOWARD STEPHENS: We've had discussions with Nexen that -- I wouldn't characterize it as any more than that, as in terms of a discussions, to this point.

MR. BOB PETERS: The agreement you have with Nexen Marketing, is to supply the primary gas and if I recall that's provided through -- through two (2) basic services, or a basic service and also a swing load service?

MR. HOWARD STEPHENS: Maybe I'll get you to just repeat the question, Mr. Peters?

MR. BOB PETERS: All right. I'd like you to describe for the Board briefly, the way the contract is structured with Nexen in terms of how it supplies the primary gas to Manitoba.

MR. HOWARD STEPHENS: There are there (3) tiers of gas supply envisioned under the contract or provided for under the contract. One (1) is the base load portion where we have 100 percent take and pay obligation, on the basis of the MDQ that we set on a month-to-month basis which means that if we -- once we set the number prior to the month occurring that we have to pay for that gas that we -- even if we don't take it we would have to pay for that gas as though we did take it.

MR. BOB PETERS: Can you explain to the Board what the MDQ acronym stands for?

MR. HOWARD STEPHENS: Maximum Daily Quantity. My apologies.

MR. BOB PETERS: And so that maximum daily quantity, is that fixed on a daily basis?

MR. HOWARD STEPHENS: No, because we are required to provide them with estimates on a quarterly basis in alignment with the provision for adjusting our MDQ for the WTS customers, we provide that information -- the last adjustment is fifteen (15) days prior to the first month of the quarter.

MR. BOB PETERS: So you have to give a forecast in advance and you tend to be conservative in that forecast so that you don't have take-or-pay gas?

MR. HOWARD STEPHENS: Yeah. It's very much a judgmental sort of a situation. You look at the weather forecast and a variety of other factors and you have to make some assumptions in terms of what the direct purchases are going to do, et cetera, but, yes, we do have to provide a forecast.

MR. BOB PETERS: In the past fiscal year, Mr. Stephens, did you have occasions where you over forecast your needs so you had to pay under the take-or-pay provisions?

MR. HOWARD STEPHENS: No. We -- well, I think we've had to pay very small amounts with respect to take-or-pay in -- on two (2) occasions; that would be two (2) days where we didn't take all the gas that we nominated.

MR. BOB PETERS: Well, when you -- when you nominate it and you don't need it, do you have to -- do -- do you actually get delivery of it so you can then market it elsewhere or do you simply pay a penalty?

MR. HOWARD STEPHENS: Well, we can obviously nominate it and do what we want with it. We would take it into the market and sell it in that circumstance even if we didn't make the entire cost -- I mean, recover our entire cost for the gas on that day.

So certainly we would take it but I mean we -- theoretically we could just leave it sit there and we'd have to pay for it.

MR. BOB PETERS: If you left it sit there, you wouldn't be able to use it at a later date?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And you said there was two (2) occasions where there was a small quantity -- there's a lot of zeros in these documents. How -- how small is the quantity?

MR. HOWARD STEPHENS: I'm just going from very poor memory, perhaps 500 gigajoules over the course of the last gas year and primarily during the summer months when it got very, very warm.

MR. BOB PETERS: All right. The -- the first of the three (3) tiers that you were telling us about was the baseload. What's the second tier?

MR. HOWARD STEPHENS: The second tier is a swing service that takes us up to -- allows us to nominate a different volume each day up to 80,000 gigajoules per day and it also allows us to make changes on an inter-day basis. I mean not only do we nominate on the day prior, but then we have opportunities in the next day to fine tune that number to ensure that we balance our takes with our puts into the system.

MR. BOB PETERS: And that's the service then as you've characterized it as -- you use the swing service to balance your -- your actual needs with what you've nominated or requested from -- from them?

MR. HOWARD STEPHENS: Yeah. We have a very variable load. Weather forecasting is not the greatest. I don't believe any one of the ones I read. So as a result of that we have to have the ability and the flexibility to be able to change our nomination relatively frequently so that we can avoid TransCanada Pipeline balancing fees which we can incur if we -- our takes don't match our -- our deliveries don't match our receipts.

MR. BOB PETERS: What is the premium that you have to pay for that swing service over baseload service?

MR. HOWARD STEPHENS: The first tier is two and a half (2 1/2) cents over index -- over the daily index.

MR. BOB PETERS: And the third tier of service you get from Nexen Marketing?

MR. HOWARD STEPHENS: Is again a swing service that allows for us to take eighty thousand (80,000) to a hundred and twenty thousand (120,000) -- that would be to deal with extremely large imbalances and it comes at a -- a five (5) cent premium over the daily index.

MR. BOB PETERS: Can you just put the parameters on that for me? I didn't quite hear you on that.

MR. HOWARD STEPHENS: That allows us to take, well, I guess it's 80,001 gigajoules to 120,000 gigajoules per day.

(BRIEF PAUSE)

MR. BOB PETERS: Can you give relative proportions to the Board as to the MDQ on the base load compared to the swing load services that you would use?

MR. HOWARD STEPHENS: It's very difficult to do, simply because the numbers vary considerably over the course of the year. The majority of the gas comes under the base load service now. I mean, obviously, the swing service, because it is a swing service and we're using it to balance the system, that number is going to vary day by day.

MR. BOB PETERS: And the gas that you're talking about, Mr. Stephens, is the system-supplied gas that Centra provides to customers who obtain their primary gas through the utility; correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And there are customers who source their gas supply from brokers.

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And if you turn with me to the book of documents, Tab number 6, there's an attachment to PUB/CENTRA Information Request 5, specifically 5(a). 5(a) deals with -- Attachment 1 deals with the number of customers.

MR. HOWARD STEPHENS: Are you looking for me to confirm that?

MR. BOB PETERS: No. I won't do that. But I do want to understand, earlier in the evidence -- well, let me just start off this way.

What we see here, if we go to the far right-hand column for March of '06, is the number of system-supplied customers is approximately a hundred and eighty-one thousand (181,000) in the residential class.

Is that correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And then if we go down halfway the page, the subtotal of two hundred and three thousand (203,000) represents the number of current customers on Centra's system that obtain system-supplied gas.

MR. HOWARD STEPHENS: That's correct. That's customers that we're serving with the supply we buy.

MR. BOB PETERS: And the customers on your system who obtain their gas from brokers are on the bottom half of the page.

Is that your understanding?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And so the residential number is fifty-two thousand two hundred and forty-seven (52,247) and the total number is fifty-four thousand seven fifty (54,750).

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: All for an aggregate of two hundred and fifty-seven thousand eight hundred and two (257,802) customers on the system.

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: Does this table exclude the power stations and the special contract customer?

MR. HOWARD STEPHENS: It does not appear to include the T-service customers, transportation-only-service customers.

MR. BOB PETERS: And those T-service customers are not system-supplied customers.

MR. HOWARD STEPHENS: No. They provide not only their own commodity but they provide the means to get it here as well.

MR. BOB PETERS: Is that -- is that correct for the power stations, they're --

MR. HOWARD STEPHENS: That's correct, sir.

MR. BOB PETERS: Okay. And the power stations are -- are owned by Centra's parent.

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: We're talking about --

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: -- a plant in Brandon and a plant in Selkirk, Manitoba.

MR. HOWARD STEPHENS: That's correct.

(BRIEF PAUSE)

MR. BOB PETERS: You concluded on the bottom half of this page western transportation service customers but you haven't included at least the two (2) classes that I just referenced, the power stations and the special contract class, which you define as straight transportation customers; correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: Can you briefly explain to the Board what is the difference between western transportation service and -- and straight transportation service?

MR. HOWARD STEPHENS: It's not as complicated as it sounds. In one circumstance under the WTS arrangements, we arrange to pick up the customers -- the broker-customers' gas at Empress on the same basis that we would pick up the gas that we buy to serve our system customers and we use our transportation assets and our storage assets, and they're served in exactly the same way as we serve our system customers.

With the transportation service customers, they basically have relieved us now of any obligation to provide gas service and/or transportation. They have to make arrangements -- upstream arrangements to acquire the gas, acquire transportation and/or storage, or whatever the case may be, to make sure that they can deliver the gas to our city gate.

And that's -- we take the responsibility then from there to make sure we get it to the plant. I hope that helps.

MR. BOB PETERS: Can you maybe explain to the Board why, for example, the power stations in Manitoba that use natural gas would decide to be transportation customers and not some other class of customer?

(BRIEF PAUSE)

MR. HOWARD STEPHENS: Generally speaking, the WTS service is -- was made available to assist smaller customers that typically have a much lower purchase load factor than our system load factor.

So they get the benefit of our assets and as a result of that, they get -- they have the opportunity to bring the gas to the market -- or we bring the gas to the market to satisfy their requirements at the same load factor which is considerably higher, given the availability of our storage, to the individual residences or businesses as the case may be.

The 'T' service customers tend to typically be very large industrial loads with higher load factors than our system will factor in there for its in their interests to acquire the supply and make their own upstream arrangements and make it much more cost effective.

It's a much more onerous service because they now have to manage the day to day deliveries of the supply and balance them on a day to day basis. And it's an interesting process, trying to make sure that those balances occur each day.

MR. BOB PETERS: What I hear from your answer, Mr. Stephens, is that the transportation class customers have to take care of all of their own gas needs and the Corporation does not provide them with supplemental gas and storage arrangements, would that be true?

MR. HOWARD STEPHENS: I'll answer the question this way. I think that our terms and conditions now refer to it as we will provide best efforts basis in terms of back stopping.

We will do whatever we can to try to make a customer happy and serve a customer if they're in difficulty or they don't have sufficient supply. But, we don't have an obligation to serve those customers. They've released us of that obligation when they signed the contract.

MR. BOB PETERS: Did you have to provide them with any service in the last fiscal year?

MR. HOWARD STEPHENS: Yeah, I think we assisted one (1) of the customers in terms of trying to balance up their load.

We interact very care -- I mean, closely with the 'T' service customers because they are such large customers, they can have a major impact -- I have to back up a step, if you'll excuse me.

We were considered because we are the taker of gas at this point in the system in the Manitoba delivery area, as the downstream operator. And that's determined by TransCanada pipelines.

They look at the aggregate gas coming to Manitoba and I mean in the aggregate gas that Centra Manitoba takes and if there's a difference between the two (2) they assess penalties.

And because the 'T' service customers are such large customers, they can have a material impact if they are not forecasting their requirements accurately in terms of driving up our cost of balancing fees.

So we work with them very closely to make sure that if they're not doing their job in terms of doing their homework in terms of serving up their requirements properly, that we're on the phone with them and making arrangements for them to get back on balance.

MR. BOB PETERS: Would it be correct that any assistance you provided to those 'T' service customers, was done solely at the cost of those 'T' service customers and was not paid for by system supply customers or WTS customers?

MR. HOWARD STEPHENS: I mean, there would be no -- I mean the fundamental premise behind providing the transportation service is there is no cross-subsidization between system customers and those transportation customers.

MR. BOB PETERS: When you are trying to do your balancing on the Centra system, are there balancing fees that you incur that you would charge back to the transportation customers?

MR. HOWARD STEPHENS: Yes, I mean, most significantly the two (2) largest customers we -- well -- I'll say there's a few, but, the two (2) largest because they are the largest can have the largest impact in terms of our balancing fees.

And to the extent that we can segregate or identify the cause and effect, we then do back charge those dollars to those customers.

MR. BOB PETERS: And that's part of the terms and conditions of the contract you have with them?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And in terms of the

Western Transportation Service customers, they are served through the efforts of the brokers, I think you've said, correct?

MR. HOWARD STEPHENS: The brokers provide the supply at the delivery point of our TransCanada contract at Empress.

MR. BOB PETERS: So the brokers arrange for -- for the supply and then it is delivered at Empress, Alberta, and Centra Manitoba then is responsible for transporting it to the -- to the city gate here in Manitoba?

MR. HOWARD STEPHENS: Yes, and if I could clarify, as a part and parcel of that -- of them delivering that gas to Alberta, we forecast the amount that we need from them. So we tell them how much to deliver at Empress and then we move it.

MR. BOB PETERS: And -- and we'll come to that because I sense there's a little friction on that issue that you can -- you can explain better later but --

MR. HOWARD STEPHENS: I think it's a black and white.

MR. BOB PETERS: You always do, Mr. Stephens. But in terms of -- the brokers source the gas and from whom they source the gas you would not know; is that correct?

MR. HOWARD STEPHENS: Well, we --

MR. BOB PETERS: Centra doesn't know --

MR. HOWARD STEPHENS: -- we --

MR. BOB PETERS: -- unless it's disclosed voluntarily by them.

MR. HOWARD STEPHENS: No, a part of the package we have to know the source of the supplier because we have to do the nomination to that supplier to deliver the gas to the system on that day so we do know the underlying supplier.

MR. BOB PETERS: But you have no control over what underlying supply is utilized by the broker?

MR. HOWARD STEPHENS: No, they dictate to us and tell us who -- who they order it from.

MR. BOB PETERS: And only if a broker had a failure of supply would Centra try to step in and help source gas from Manitoba consumers who use broker -- brokers?

MR. HOWARD STEPHENS: There again we have -- well, there's a backstopping service and there's a variety of different services that we talk about in our terms and conditions but we certainly won't let customers go cold and if a broker has difficulty, we will do our best to try and satisfy the requirements and then -- but the understanding is that whatever costs we would incur, they would be passed onto them.

MR. BOB PETERS: In the past fiscal year have there been any such circumstances where Centra has had to backstop a broker?

MR. HOWARD STEPHENS: No.

MR. BOB PETERS: And -- and in fact, perhaps historically, it's been many years since that's occurred?

MR. HOWARD STEPHENS: It depends -- depends on your definition of "many years". I can think of a circumstance within the last couple of years.

MR. BOB PETERS: Can you describe that to the Board? And -- and I'm not asking for at this point disclosure of the -- of the broker but detail the situation.

(BRIEF PAUSE)

MR. HOWARD STEPHENS: I think I misspoke myself, Mr. Peters, it was actually a 'T' service customer that we assisted and not a WTS customer.

MR. BOB PETERS: All right. Thank you for that. And -- and while --and while Centra arranges the transportation of the broker gas to Manitoba, the cost of that is included in the transportation rates that the broker's customer pays?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And then when it gets to the city gate and the city gate is -- much be some engineering term that I don't understand, but you have many city gates; do you not?

MR. HOWARD STEPHENS: Yeah, I think the last count was twenty-six (26).

MR. BOB PETERS: And a city --

MR. HOWARD STEPHENS: Those are the actual take-offs off of TransCanada Pipelines.

MR. BOB PETERS: All right and that's -- that's the receipt point that you have somewhere in Manitoba from the TransCanada Pipeline service?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And --

MR. HOWARD STEPHENS: There's a meter station there and we meter the gas off of TransCanada's system and we take it to serve the various towns in rural Manitoba and Winnipeg, et cetera.

MR. BOB PETERS: All right. And did you say twenty-six (26)?

MR. HOWARD STEPHENS: That's the latest count. I won't swear by that number.

MR. BOB PETERS: All right. Is Minell a

city gate?

MR. HOWARD STEPHENS: Yes, it is.

MR. BOB PETERS: All right. And once it's at city gate it comes onto the Centra distribution system and the broker's customers then are responsible for the distribution costs through a distribution rate?

MR. HOWARD STEPHENS: They pay, precisely. All the other rates on their bill, the ones that you referred to earlier in terms of the breakdown of the bills, are exactly the same as a system supplied customer except for the commodity charge and the commodity charge is that number that has been agreed to between the customer and the broker.

MR. BOB PETERS: Does Centra bill all Manitoba western transportation service customers or do some brokers invoice their customers separate from Centra?

MS. LORI STEWART: Yes, some customers do not utilize our agency billing and collection system otherwise known as "ABC".

MR. BOB PETERS: You said, "some customers," Ms. Stewart, you meant some brokers don't utilize the ABC service?

MS. LORI STEWART: That's -- well, some brokers for some of their customers, yes.

MR. BOB PETERS: All right.

MS. LORI STEWART: That is a broker may have both customers who are utilizing agency and billing collection service and may also represent some customers who are not utilizing ABC service.

MR. BOB PETERS: And for those brokers who have customers and utilize the ABC service, the agency billing and collection service, you charge an amount for that, would that be correct?

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

MR. BOB PETERS: Is that still twenty-five (25) cents a bill?

MS. LORI STEWART: Twenty-five (25) cents per month per customer, yes.

MR. BOB PETERS: Thank you.

Mr. Chairman, I wanted to turn to a new area and I could maybe get it wrapped up in about ten (10) or fifteen (15) minutes, or this might be a place to take a lunch recess, at the pleasure of the Board.

THE CHAIRPERSON: I think we'll pick the latter. If we could come back at one o'clock, if no one minds. Thank you. We'll see you at 1:00.

--- Upon recessing at 11:59 a.m.

--- Upon resuming at 1:05 p.m.

THE CHAIRPERSON: Okay. Mr. Peters, any time you're ready to start.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Yes. Thank you, Mr. Chairman.

Panel, before lunch we were talking about gas supply, storage and some transportation issues and I wonder if you could turn, please, to Tab 3 of the book of documents. And in Tab 3 of the book of documents there are three (3) pages, they're from Tab 3, Attachment 1 of the application, Tab 3, Attachment 2 of the application, and Tab 3, Attachment 3 of the application.

Mr. Stephens, would I be correct in assuming that you would have the greatest familiarity with this chart and map?

MR. HOWARD STEPHENS: Certainly I've seen it most frequently, yes.

MR. BOB PETERS: All right. Could you please then briefly explain to the Board what the Tab 3, Attachment 1 document is -- is showing the Board?

MR. HOWARD STEPHENS: Okay. That is essentially our summer operations, which occur from April 1st through to October 31st. And if you follow the pink line, which is TransCanada pipelines, we take delivery of the gas at Empress, which is off this map, off on the left side. We haul the gas across Saskatchewan, drop some -- and it's not shown on this map but we do drop some at the Minell pipeline at Moosomin, at the Saskatchewan/Alberta border -- or Saskatchewan/Manitoba border, I apologize.

And then the remainder of the gas in the summer months we take to the Winnipeg load and then in -- anything in extent of that or excess of that we -- up to the limit of the -- the Great Lakes capacity, we move down the orange line, which is the Great Lakes pipeline, which goes down then again on the green line, which is ANR pipeline, and around the lake and comes back up into ANR storage, just -- I guess that's east of the -- east of the lake.

And we don't have any particular storage site that we can go and point at and say, That's where our gas is. This is just a notional point that we -- I mean, we send the gas to -- we make the nominations for the gas to materialize into ANR's account. I mean, they -- they account for it and they get it on the books and they know -- I mean, and there are certain restrictions and parameters associated with the contract that we have in terms of how much gas we can put on a given day and how much gas we can take out, et cetera, et cetera.

MR. BOB PETERS: Mr. Stephens, recognizing that it shows up on ANR's records, that simply means that they have some of your gas in storage, either physically or notionally, and you're entitled to it under the --

MR. HOWARD STEPHENS: That's right.

MR. BOB PETERS: -- terms and conditions that you have agreed to.

MR. HOWARD STEPHENS: That's right. But there's no -- no coloured molecules with Centra written on them.

MR. BOB PETERS: All right. And, in fact, in terms of the storage capability in that Northern Michigan area, ANR has a fairly vast complex where it stores --

MR. HOWARD STEPHENS: Yes.

MR. BOB PETERS: -- gas for many, many companies.

MR. HOWARD STEPHENS: Yeah. Very many -- yeah, there are a large number of counterparts, although we are -- I can't think -- I think it's second or third largest holder of storage in that area.

MR. BOB PETERS: All right. So the Manitoba -- the gas that Centra buys from Alberta follows those blue arrows --

MR. HOWARD STEPHENS: I should point out though, I mean, and that's -- that would be what we would refer to as a -- to a normal or a typical year. And to the extent that the winter has been colder and we've depleted storage down below, approximately 10 million gigajoules, then we will bring on either the Oklahoma supply on ANR southwest piece, that's where we have the FTS service for 7860 gigajoules. And to the extent that our refill plant still requires more gas than that, we have the ANR southeast piece which provides for 22,380 gigajoules.

And during the summer -- that's a summer only service. It's -- and really it's anticipated that we would only use that capacity after a design year where we're fully depleted storage.

MR. BOB PETERS: Would you consider that gas that you just talked about from Oklahoma or Louisiana as being primary gas or would you consider that supplemental gas?

MR. HOWARD STEPHENS: That's supplemental gas. And you can see the various fuel factors, there's fuel associated with each leg of the transportation that we have to move.

We have a short piece of -- and actually it's indicated in orange, but it's called STS, right off the pink line below Winnipeg we have a short piece of STS service which allows us to move gas to our -- to the Great Lakes in the summer months.

MR. BOB PETERS: And when you say, STS, does that have any --

MR. HOWARD STEPHENS: Storage, transportation, service.

MR. BOB PETERS: All right. And then in terms of fuel gas, can you explain to the Board what the fuel gas ratio indicated is for?

MR. HOWARD STEPHENS: Well, as an example, for the TCPL, 203,600 Gj's, which is the combination of our SSDA, Saskatchewan take-off and our Manitoba take-offs, we pay 1.66 percent -- yes -- we provide -- or we provide 1.66 percent more gas at the receipt end of the pipe, as compared to what we get at the delivery end of the pipe.

And that's the gas that's required to fuel the compressors along the pipeline that help move the gas, you know, along the pipeline.

MR. BOB PETERS: Mr. Stephens are -- is there a movement afoot for some of those compressors to be converted to electricity or electric sources?

MR. HOWARD STEPHENS: They have done some in Saskatchewan and some in Manitoba. There -- well, right now TransCanada has a fuel incentive mechanism program where they reap the benefits of any savings associated with improvements in terms of reductions in fuel costs.

So they're looking very hard at those areas where they can put electric compressors in on a cost effective basis.

MR. BOB PETERS: And how do you account for the payment of that electricity that is used by TransCanada pipeline to fire up those compressors?

MR. HOWARD STEPHENS: They pay Manitoba Hydro for the -- for the electricity they have to use in that circumstance. And then we would -- I mean we're providing fuel on an entirely different basis than it is on a class basis.

MR. BOB PETERS: All right. I think that -- unless you have any other comments about the summer operations, we could turn the page to attachment two (2) and perhaps you can explain to the Board what happens in the winter operations.

MR. HOWARD STEPHENS: Certainly. Again, we have -- we picked up the gas on the left side of the map at Empress, which is not described. We move gas to Winnipeg and for the most part -- and it is from the period from November 1st through to March 31st, in a year.

We move the gas to the Manitoba load and once we get into weather that's anything significantly below an average of say about minus five (-5) degrees, we'll use up all of our TransCanada capacity to Winnipeg, to serve the requirements.

And then in addition to that, we will require alternate supplies. Our official dispatch plan calls for us to look at -- bringing the 7860 gigajoules of gas from the ANR southwest pipeline up to and back haul it on the Great Lake system to Winnipeg, as the next tranche is supplied to satisfy the market requirement.

And now when I say "back haul," that's not actually going backwards, well, it has on a few occasions, but that's an exception and hopefully it won't happen very often. This is really an exchange of volumes, we just intercept volumes that otherwise would have gone done the Great Lake system and replace them, where we would -- at Crystal Falls where we would normally deliver the gas on the Great Lake system.

And we'll actually talk about that later in terms of the capacity management program because that is one (1) way that we can turn a buck on our assets.

We do have the ability during the course of the winter months, also, and I should have indicated the same thing, either bring the gas into storage from the southwest, as well. So if we're depleting our storage, we have the opportunity for bringing some gas into storage.

The southwest capacity, as I indicated before, is not available to us during the summer -- or the winter months. And yet -- one (1) thing I should indicate is that our storage is seasonal storage. The summer season, we're only allowed to inject. In the winter season, we're only allowed to withdraw.

So there is no -- while there are again exceptions to every rule, but I mean for in general -- in general principles that's -- that is the -- the way the portfolio is constructed.

MR. BOB PETERS: Mr. Stephens, if I can just back up on that -- on that back haul explanation you provided, recognizing that Centra has gas in storage in northern Michigan and you may have occasions where you then need it, rather than physically transport the molecules from northern Michigan back to Manitoba you say you exchange gas with some party; is that right?

MR. HOWARD STEPHENS: Well, we essentially exchange gas with Great Lakes.

MR. BOB PETERS: And Great Lakes, you will take off of the TransCanada Pipeline gas that would otherwise be designated for Great Lakes?

MR. HOWARD STEPHENS: Somewhere downstream of Great Lakes -- downstream on the Great Lakes system

MR. BOB PETERS: Right, and you would take it off at Winnipeg and then they would inject it from storage to supply whatever customer that was initially intended for that volume.

MR. HOWARD STEPHENS: Well, the second part of that transaction is that we will nominate a portion of the supply out of our storage onto their system. So it now has replaced that volume with gas that we took upstream.

So there is -- there are no physical molecules moving in that transaction between Winnipeg and Crystal Falls.

MR. BOB PETERS: And in terms of the gas you put into storage, the majority of that gas is considered primary gas?

MR. HOWARD STEPHENS: Well, we do put some supplemental in there depending upon, again as I mentioned, it depends on how depleted storage has been at the end of the winter and what sources of supply we'd have to bring in to refill storage. And if it's been a very cold winter then there will be more supplemental gas in storage than in a normal -- normal year case.

MR. BOB PETERS: Is there any suggestion from perhaps some of the discussion that I've heard from Ms. Derksen this morning that there will be a point in time when supplemental supply will not be -- will not be needed for Manitoba under your present arrangements?

MR. HOWARD STEPHENS: Well, certainly when we do our next analysis with respect to the portfolio there's a number of factors that drive you out or you have to look at in terms of determining whether or not you're going to hang onto the American's base pipe and what we would refer to as supplemental gas.

One (1) of the significant factors though right now is certainly the load reduction or the conservation effects that we've seen and a result of that Miss Derksen or Ms. Derksen, I should say, or Mr. Sanderson indicated that we potentially could have a situation where we don't have any supplemental gas.

And for this coming winter we have been able to divest ourselves of that US pipeline capacity and satis -- and in exchange for that we've got an additional storage capability and it's helping us to not only save a dollar but it's allowing us to serve up our previously uncontracted peak day.

(BRIEF PAUSE)

MR. BOB PETERS: Those may be matters that Mr. Sanderson and I should remember to speak about but by divesting yourself of some of the US pipeline obligations that would, in essence, potentially reduce the gas costs for '06/'07?

MR. HOWARD STEPHENS: Potentially yes and well, actually there are revenues associated with that because we are selling -- assigning that transportation to a third party and we are making revenue as -- as a result of that. So it's got multiple benefits associated with it.

MR. BOB PETERS: And will that revenue show up in the capacity management revenues?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: All right. And, Mr. Stephens, in terms of the US operations that we see, there's an arrangement that Centra has with ANR to provide the transportation and the storage and there's a cap on that, is that correct?

MR. HOWARD STEPHENS: In terms of the revenue cap you're -- you're speaking of? Yes.

MR. BOB PETERS: Yes.

MR. HOWARD STEPHENS: Yes, it's a --

MR. BOB PETERS: There's a maximum amount that Centra has to pay for the US assets that it has.

MR. HOWARD STEPHENS: There's a fixed amount that Centra has to pay with a limit on it and it's $14,700,000 dollars US and it's been that since the outset of the contract in 2000 -- 1993.

MR. BOB PETERS: If there was no supplemental gas needed for Manitoba you wouldn't have to pay that cap, you would -- you could potentially pay less than that cap, is that correct?

MR. HOWARD STEPHENS: No, the construct -- contract still contemplates us paying that cap. We would still have to pay the same revenue requirements. Now, I will receive revenue from the counterpart that I've sold the capacity to and that offsets the cost that I'm bearing or incurring from ANR.

MR. BOB PETERS: That $14.7 million US cap relates to the transportation of both primary and supplemental gas though, correct?

MR. HOWARD STEPHENS: That's correct. Well, they don't distinguish between the two (2), they just send me a bill for the transportation and storage.

MR. BOB PETERS: Mr. Sanderson, in terms of the supplies that Centra arranges you have to have a system that's designed to meet the -- the design for a peak day.

Is that correct?

MR. HOWARD STEPHENS: I may want to jump in.

MR. BRENT SANDERSON: Oh, I'm sorry, I --

MR. BOB PETERS: Whomever.

MR. BRENT SANDERSON: In terms of a system that would deliver that gas, yes, I would agree.

MR. BOB PETERS: And in terms of the source of that gas, that's your responsibility, to line up the source?

MR. HOWARD STEPHENS: No. That's my responsibility.

MR. BOB PETERS: All right. Then in Tab 4 of the book of documents there's an extract from the application, Tab 3, page 8 of 13, and it shows that there's a total design firm peak requirement of 447,400 gigajoules on that peak day.

Is that right?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And when -- when did that peak day occur?

MR. HOWARD STEPHENS: It has never occurred to -- since we've forecast that number. That is our new forecast number after the effects of conservation.

We had a peak day -- our highest peak day occurred on February 2nd, '96. I remember this quite distinctly because I was the one that was buying a shortfall of gas that we needed to buy at the point in time and it was -- I set the record that day in terms of high price for gas.

MR. BOB PETERS: And that February 2nd, 1996, is on record then as being the peak day that the Manitoba system has had to meet?

MR. HOWARD STEPHENS: No. We do a -- I mean, our forecasting group looks at our use per customer and then looks at the customer base and provides us with an updated peak and annual load requirement, because we want to contract or have under contract the appropriate amount of gas to serve the market.

And to the extent -- and for the most part over the years the market has grown. So you want to be mindful of the growth and -- and at some point it becomes critical that you now add additional assets to satisfy that peak day requirement for the firm customers.

But we are facing the opposite problem right now on basis of all indications that our load is actually growing smaller as a result of conservation, although I'm not prepared to hang my hat on that and decontract anything yet. If it occurs over several years, certainly it's something that we'll have to be mindful of.

MR. BOB PETERS: An you're showing the Board then on -- in Tab 4 of this book of documents that has been prepared, where Centra will obtain the molecules to meet the new forecasted firm peak design.

MR. HOWARD STEPHENS: Well, this is the general dispatch rules that we use. We will use some discretion with respect to where we take, sort of, the sources of supply depending upon the price. We won't necessarily take the Oklahoma supply if there is delivered service available from the WCSB or Alberta and move it to the Manitoba load and -- and then hold back storage or retain storage in order to serve the remainder of the winter.

So we look at the most cost-effective way to serve the load. This is the general -- this is the design of our portfolio to satisfy the Manitoba requirements. It -- it's not cast in stone though, and I guess that's really the message I'm trying to get across.

MR. BOB PETERS: If I turn back with you, Mr. Stephens, to Tab 3 of the book of documents and look at the last page in Tab 3 of the book of documents, there is another depiction of that peak day requirement, this time in chart form, coloured chart form, and --

MR. HOWARD STEPHENS: You sound surprised that it's coloured.

MR. BOB PETERS: It makes it easier for me to understand, but what you're demonstrating to the Board here is when that peak day that you forecast occurs, based on your present forecast, that's how you're going to meet it.

You're going to start off with your TCPL firm transportation and progress through the different layers that you have available to you.

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: I note that the peak day and the delivery -- daily delivery capabilities may not match up and they are -- they are not the same due to the interruptible load?

MR. HOWARD STEPHENS: That's correct. We don't pre-contract to satisfy interruptible load. They're there to fill the valleys when we have excess capacity.

MR. BOB PETERS: Is the -- is their capacity included then in -- in what you would otherwise use on that day ordinarily?

MR. HOWARD STEPHENS: Well, for the most part we're not using our peak day -- peak day assets.

We're not utilizing -- fully utilizing them all so to the extent that we're not utilizing them all, we serve the interruptible customers.

MR. BOB PETERS: And --

MR. HOWARD STEPHENS: It's only when you get into periods of extremely cold weather and that we don't have additional supplies to make -- keep them on a system that we ask them to curtail.

MR. BOB PETERS: And those peak -- I'm sorry, those interruptible customers that you would curtail on a peak day, I believe are forty-six (46) in number.

Does that sound approximately right?

MR. HOWARD STEPHENS: I'll -- I'll give you the number; it's a little bit lower than I'd heard but that's possible.

MR. BOB PETERS: Okay. And although you may interrupt those customers and I think -- I think Ms. Derksen indicated there was a rate concession for interruptible customers and that's to reflect the fact that you may interrupt their service because you needed to meet another part of your load?

MR. HOWARD STEPHENS: Yeah, we have the interruptible customers to serve to two (2) purposes. One (1) is to -- typically if you have a -- a market that's growing you build you distribution system in such a way that you build it in -- I'll call it "chunks" where you've got existing capacity to serve your firm load, but then as your load grows you'll have to put another layer of capacity in to serve the market.

In that interim process, because you're building excess capacity because that's the most cost effective way to do it, your distributioning system can handle additional customers and that's where interruptible customers come in because on those days when we're not using all that capacity we can provide them with service.

So from a distribution perspective they serve -- they serve one (1) purpose and then from a gas supply perspective they serve another purpose in terms of my being able to shed some load that could -- could potentially be a very high cost and having let them then go into an alternate supply.

MR. BOB PETERS: And in the event that Centra does curtail the interruptible customers, Centra is also available to try to source gas for them, is that right?

MR. HOWARD STEPHENS: Yes, we're now in the position where our distribution system is pretty much -- can pretty much handle the entire load that we have on the system including the interruptible customers even on a peak day. So in that circumstance, the extent that gas is available at a price that the customers are prepared to pay, we're prepared to acquire it and pass it through to them.

MR. BOB PETERS: And when you pass it through you call that your alternate service for those interruptible customers?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: Do I gather correctly then from what you were saying is probably last year the interruptible customers were not curtailed?

MR. HOWARD STEPHENS: No, they weren't curtailed last year; we had lots of gas.

MR. BOB PETERS: Does that beg the question then as to whether or not their rate is adequately designed to reflect the interruptible capabilities of the Corporation?

MR. HOWARD STEPHENS: I think at some --

MR. BOB PETERS: Have you had time to reevaluate that?

MR. HOWARD STEPHENS: It's something we have to be mindful of. I don't know the last time Ms. Derksen had a look at that but certainly the relative value that they get, relative as compared to the rate, needs to be continually scrutinized.

MS. KELLY DERKSEN: And I'd like to add, Mr. Peters, that we don't know how permanent this -- the predicament that we're in and so until that we have some assessment of that, it's -- it's difficult to -- to draw final conclusions.

MR. BOB PETERS: Maybe you can help me understand that, Ms. Derksen.

When do you get an assessment of that or how -- how would you do that or when would you do that?

MS. KELLY DERKSEN: It would take us several years, Mr. Peters. One (1) year is not -- one (1) year is not an indication of -- of if that's something that can be expected in -- in terms of load requirements and so it could be two (2), three (3), four (4) years before that we can conclude one way or another what kind of position that the -- the Company is in terms of serving load.

MR. BOB PETERS: So you're hoping for weather like last winter but you're not prepared to redesign the gas supply portfolio around that expectation?

MS. KELLY DERKSEN: That's probably a fair statement.

MR. BOB PETERS: So in the meantime, Mr.

Stephens, you have those assets that you've shown us on those maps in terms of getting -- getting gas to and from storage and to meet the peak day, and if Centra is not in need of all of those assets you're telling the Board that you try to sell them off or package them up in a way that the corporation can recoup some of the cost.

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And there are fixed costs associated with some of those assets so that it's really a take-or-pay type arrangement that if you -- even if you don't use it you have to pay for it because it's being reserved for you --

MR. HOWARD STEPHENS: Well, the best example would be the capacity we hold on TransCanada pipelines. We have to contract for 200,000 gigajoules a day, each and every day. We pay a demand charge based upon that. We get charged that demand charge twelve (12) months a year and whether we use it or not.

And, I mean, obviously in the summer months, I mean, we're using a fraction of that. So to the extent that we can divert that capacity down the stream further and extract some revenue associated with that, it goes to offset the demand charges that we -- we are being charged.

MR. BOB PETERS: For the year 2005/'06,

for which you're seeking board approval of the final gas costs, Schedule 4.3.1 as provided in Tab 8 of the book of documents, it's actually the second document in that tab and it's Schedule 4.3.1.

MR. HOWARD STEPHENS: I have it.

MR. BOB PETERS: And this is the representation of the capacity management that was actually taken -- that actually took place in the '05/'06 fiscal year.

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And where it lists sales revenues, those are sales of excess Western Canadian supply at Empress that you may have?

MR. HOWARD STEPHENS: It would be a commodity either in the form of sales from Western Canada or inventory from storage.

MR. BOB PETERS: And it shows here that you didn't have any sales.

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: Even in the warm -- was that not, you know, warm enough to generate that, you had no excess capacity?

MR. HOWARD STEPHENS: Well, we fully utilized all of our pipeline capacity. It didn't get that warm during the course of last winter. And certainly by the time we were in a position to say with absolute certainty that we weren't going to require the remainder of our storage, everybody was in the same boat. I mean, they had -- they ordered long storage and the market for it wasn't exactly very attractive.

So we look at that relative to the replacement cost and we were better off to leave the gas in the ground.

MR. BOB PETERS: It was worth more to you to keep it in storage or --

MR. HOWARD STEPHENS: More cost effective way to serve the load for the customers in the upcoming season was for us to leave that gas there and not have to replace it with something more expensive.

MR. BOB PETERS: So the -- so the sales revenue could be sales from Western Canada or it could also be sales out of storage, which could be Western Canada gas in storage.

MR. HOWARD STEPHENS: Yes. With one -- the one (1) caveat, that our existing gas supply contract prevents us from buying gas from our gas supplier and then turning around, buying gas, say, under our base load contract, which is a monthly indexed contract, and then turning around and selling it into a daily indexed market, where the price may have dropped. And we used to make a fair bit of change doing that, but that's not -- it's not the case anymore because they are exposed to that difference in price.

MR. BOB PETERS: So you're saying Nexen doesn't allow you to -- to take a -- max out on your daily quantity, even though you don't think you're going to need it, with the intention of taking it and selling it on a secondary market.

MR. HOWARD STEPHENS: That's right. Under the old TCE contracts, you'll recall, we used to do a considerable amount of that, where we would be selling if the money -- if our contract price was in the money we would certainly be buying everything we could buy and selling it to whoever we could sell it, and in fact we were selling it back to the people that we were buying it from and making a change on that.

MR. BOB PETERS: The next item on Schedule 4.3.1 shows capacity release revenues. And I understand those are the temporary sale of transportation capacity, either alone or perhaps bundled with some commodity?

MR. HOWARD STEPHENS: Typically those are -- I mean, the capacity release is the example I gave you was TransCanada pipelines. We have a delivery point in the Manitoba delivery area, as well as the Saskatchewan delivery area. TransCanada provides a service for anybody that's contracted with the FT service, firm transportation service, that we -- that's available on their system. And they allow you to divert that capacity further downstream if they have no operational difficulties, et cetera.

So we can sell that capacity or that -- take those diversions and sell that capacity, and then the revenues that we generate associated with that, again, go to offset our fixed costs associated with those assets.

MR. BOB PETERS: So when you show a revenue from capacity release of $6.2 million, you also have some costs.

And how is it that you incur costs when you're releasing capacity?

MR. HOWARD STEPHENS: Because I'm now taking the gas further down than our existing delivery points so -- and TransCanada charges you on the basis of distance. So if I now take -- instead of taking the gas and delivering it into the Manitoba delivery area I say I'm going to divert some of my capacity to Don (phonetic) all the way to the other end of the pipeline, they charge me the toll associated with that.

And the component in terms that -- results in revenues is the fact that we will recover some of the costs on the already sunk costs that we paid from -- paying for the pipeline capacity from Empress to the MDA. And I hope I haven't confused you more than helped.

MR. BOB PETERS: No, I understand the point. So when you -- when you do have a capacity release transaction you -- you go looking for places to -- to sell the capacity even if that means you have to incur some incremental costs to do so?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: But if you do incur incremental costs, the revenues have to exceed those incremental costs before you will enter the transaction?

MR. HOWARD STEPHENS: That's right.

MR. BOB PETERS: So at no time would the Board ever see a Schedule 4.3.1 with -- with negative numbers in terms of your capacity management transactions?

MR. HOWARD STEPHENS: Well, if the Board saw it I likely wouldn't because I wouldn't be here so I ask -- the short answer is no.

MR. BOB PETERS: All right. I think we've got the point. And -- and before I move past those sales revenues, you told me that Nexen doesn't allow you to -- to buy from them and then sell on the market knowing that you really didn't need all of what you purchased from them.

Is that an item that the Corporation is looking at in its new gas supply contract, the ability to do that?

MR. HOWARD STEPHENS: Well, it's one (1) of the many variables you look at in terms of the overall package in terms of the contract and there's a certain value associated with that.

MR. BOB PETERS: Well, you --

MR. HOWARD STEPHENS: But you -- I mean it's -- depending upon the nature of the contract, if you can get something else that is of greater value to you, then I would suggest that you would -- it's like a bird -- well, a bird in the bush is worth six (6) in your -- well, six (6) in your hand or whatever the saying is but I mean -- sorry, I'm confused.

MR. BOB PETERS: It's a new -- it's a new saying. We like it.

MR. HOWARD STEPHENS: You -- you know what I mean.

MR. BOB PETERS: I -- I do, Mr. Stephens, and the -- but the point I'm asking is --

MR. HOWARD STEPHENS: You guys aren't supposed to be laughing.

MR. BOB PETERS: Under the -- under the old TCP or the Western Gas Marketing Limited and successor companies you had the ability to -- to purchase up to your MDQ and then sell it as you fit.

MR. HOWARD STEPHENS: Which we paid a term factor for and some premium associated with it.

MR. BOB PETERS: All right. I appreciate that but you also made a -- a healthy profit on some of that?

MR. HOWARD STEPHENS: Yeah, but that would be -- the -- the nature of that contract was -- was not separated into the different three (3) categories -- sorry, categories that we talked about earlier. We simply had an -- a contract with what was referred to as an "operating demand volume" which allowed us to take anywhere from zero to the maximum of the contract. And on -- I mean and the only obligation we had under that contract was to meet the annual load factor obligations that they set out for us.

So from the perspective they incented us to go out and sell gas into the secondary marketplace because we had to meet an annual load factor obligation and if I -- we had a very warm winter and we weren't in a position to take all the gas that we had to under the contract, it would put us at a disadvantage.

So that was something that we negotiated into the -- into the contract.

MR. BOB PETERS: All right. My -- my point I suppose was in preparing your shopping list as you consider with EEA whether to renew with Nexen or seek a new gas supplier or gas suppliers, that's one (1) of the factors that you will be considering?

MR. HOWARD STEPHENS: Certainly.

MR. BOB PETERS: All right. When we get down to the Schedule 431 to the -- to the loans revenues or loan revenue, I understand loans to be short-term loans that you take out of storage and then have them replaced subsequently?

MR. HOWARD STEPHENS: That's a fair depiction.

MR. BOB PETERS: And it appears you didn't do any of that in '05/'06?

MR. HOWARD STEPHENS: No, I mean technically speaking we didn't have any transactions that we described as loans. They typically are fairly high risk and very low revenues associated with it so the risk return equation doesn't really fit very well from my perspective. And there isn't that many -- much demand for it.

MR. BOB PETERS: When we get down to

exchange revenues, those are physical swaps that you would make; either a third party provides it here to Manitoba or Centra ships it off to Michigan or something along those lines?

MR. HOWARD STEPHENS: It's essentially the same as what I described on the winter operation map where we take gas in -- in Winnipeg and then send an equivalent amount of gas out of storage onto the Great Lake system further down on the Great Lake system and we provide -- we're providing a virtual transportation service for a third party, and we charge them a fee for that.

MR. BOB PETERS: When you aggregate all of your capacity management activities, they came out to $5.746 million, you added some carrying costs or what I always think of as interest costs, again in the favour of consumers and you have reduced gas costs in '05/'06 by $5.883 million.

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: All right. If we turn please to Tab 7 of the Book of Documents and look at schedule 4.0.0 and we look in the middle column of 2005/'06 actual totals and go down to line 56, we're going to see that $5.7 million repeated there, correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And what's not shown there is the carrying costs, but those are in addition to that amount?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And when you -- in the direct evidence through Ms. Murphy, the Corporation is asking this Board to grant final approval of 2005/'06 gas costs and that total is found on line 58 of schedule 4.0.0 in the amount of $389.66 million.

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: Ms. Derksen, I think in one (1) of the Information Requests and please don't ask me which one, I think we asked you what would be the result of your updating that number more current with this Hearing to take into account any changes in the forecast carrying costs, do you recall being asked that?

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, rather than make that a memory test, let me -- let me word the question maybe this way.

If you were to look at schedule 4.0.0 and update it for any changes to the actual carrying costs that were incurred, recognizing that some of these forecasts were prepared before the carrying costs were finally known, is there going to be a significant or any change that you know of?

MS. KELLY DERKSEN: Very little change, if any, Mr. Peters.

MR. BOB PETERS: All right. And if there is a slight change and I know we're not quantifying it, Ms. Derksen, where would that change be captured?

MS. KELLY DERKSEN: It would be captured in the relevant deferral or PGVA account.

MR. BOB PETERS: So to the extent that there may be additional costs incurred by the Corporation that are not being recovered, you would include those in the PGVA accounts and recover them next year?

MS. KELLY DERKSEN: Recognizing that this number is as close to final as -- that we can get, there's going to be very little impact to any of the PGVA accounts but, if there were, that's how we would propose to deal with it.

MR. BOB PETERS: All right. Still staying with that middle column on schedule 4.0.0, found at Tab 7 of the Book of Documents, the fixed costs that are shown there, those represent primarily the storage and transportation costs, would that be fair?

MR. BRENT SANDERSON: Yes, that's

correct.

MR. BOB PETERS: And, Mr. Sanderson, can you explain then to the Board what the variable transportation costs are?

MR. BRENT SANDERSON: The lion's share of what we pay for our storage and transportation arrangements are charged to us in the form of demand charges which Mr. Stephens described that they're fixed in nature and don't change month to month relative to the volumes that we transport under those contracts.

There are certain variable tolls which are charged in addition to the fixed monthly demand charges that do vary in relation to the units of commodity volume, we transport under those contracts or are related to compressor fuel to move the gas down the respective pipeline systems.

And so those are what we have characterized under variable transportation costs. And they're much lesser amounts relative to the monthly demand charges.

MR. BOB PETERS: Mr. Sanderson, I take it is one of your responsibilities to keep track of the changes from forecast to actual on -- on these costs.

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: Can you explain to the

Board just a couple of selected items, maybe starting at line 3, the TransCanada pipeline firm service demand to the Manitoba zone. You forecast that last time you were before the Board at 24 million, it comes in closer to 22.6 million.

Can you explain the -- the reasons for that?

MR. BRENT SANDERSON: That would have been a result of a number of the TCPL toll reductions which were passed through to shippers that Mr. Stephens described in his examination in-chief.

MR. BOB PETERS: And looking in the variable transportation costs, Mr. Sanderson, down to line 30, storage gas, transportation and delivery cost, estimated at about 5.5 million, it came in at 1.75 million. Why the -- why the reduced cost?

MR. BRENT SANDERSON: Well, our storage -- our transportation and delivery cost would have been much lower last winter due to the extraordinarily warm weather that we experienced. We would have utilized our storage to a much lesser extent than we would have forecasted under normal weather conditions.

So to the extent that our storage charges are assessed on units of volume withdrawn from storage, you would see a much lesser total charge for those types of charges on an actual basis relative to forecast.

MR. BOB PETERS: And how does that fit under the cap of the $14.7 million US that Mr. Stephens told us about?

MR. HOWARD STEPHENS: Well, the total cost or the total bill that we would incur from ANR is twenty -- no, $14,700,000, and those costs are incorporated into the model based upon a calculation that ANR puts together in terms of a full utilization of -- of the facility.

So it's from that perspective that we -- we would pay for it.

(BRIEF PAUSE)

MR. BRENT SANDERSON: Actually, those charges, much of those charges which are characterized as storage, gas transportation and delivery cost, are not subject to the $14.7 million revenue cap. The lion's share of what those charges represent is pipeline compressor fuel that we -- the cost associated with that that we incur during the summer months to move gas to our storage facility.

We inventory those costs in the summer months and then as we withdraw the inventoried commodity and its associated cost and deliver that to the market, we also withdraw those inventoried variable transportation costs, which are largely compressor fuel, and we book those costs as expenses.

So they're subject to a lot more variability than any of the charges that would be covered under the revenue cap. So most of that is inventoried compressor fuel costs that were inventoried in storage in the summer.

(BRIEF PAUSE)

MR. HOWARD STEPHENS: The reason we're having some difficulty with this, sir, is that there's two (2) components lumped into that. There's the compressor fuel as well as the variable commodity charge, which the variable commodity charge is part and parcel of the revenue cap. It is incorporated into that.

The fuel costs are not because they're not predictable. So the fuel costs are distinct and separate.

MR. BRENT SANDERSON: But of the $5.5 million that we have forecast at the outset of a -- you know, we would expect to incur in a normal year, the lion's share of that is compressor fuel, not variable charges subject to the $14.7 million revenue cap.

MR. HOWARD STEPHENS: Which is consistent with our -- my comment earlier in terms of the arrangement is pretty much a fixed cost arrangement. It's very heavily weighted towards the demand charge and a very minor amount of the cost associated with the ANR service is billed out as a commodity charge or a variable charge.

MR. BOB PETERS: Did the forecast, Mr. Sanderson, that is in column 1 on Schedule 4.0.0, did that -- did that, if you added up all those components, did that have the $4.7 million US cap in that forecast, or was it some other amount, have you broke it out?

MR. BRENT SANDERSON: You have to be more specific as to what particular item you're referring to.

MR. BOB PETERS: Well, I'm referring to all of the items that are covered under the -- under the revenue cap, that you call it.

And if I pick out those individual line items and segregate them so that they are pursuant to the contract that you have with ANR, is -- will it total $14.5 million in that first column?

MR. BRENT SANDERSON: If you were to be able to break out every element of the gas costs forecast which is subject to the $14.7 million US revenue cap, yes, we verify every time at the outset of a year when we forecast our gas costs that, indeed, our forecast costs are under the $14.7 million revenue cap.

And I would put to you that it's a little bit less, in the order of a hundred to a hundred and fifty thousand dollars ($100,000 to $150,000) less than the $14.7 million revenue cap.

ANR strives to calculate its tolls to us, fixed versus variable is such that they strive to recover $14.7 million but, it's based on a moving target. Because as you know, our forecast load changes from year to year.

So it would be somewhat different than that, but we always do yes, verify that we are not paying charges to ANR in excess of that $14.7 million US -- $14.7 million US revenue cap, relative to the charges that are covered or under that cap.

MR. BOB PETERS: So while the forecast took that into account, you're also telling the Board that the actual costs in the middle column for 2005/'06 actuals, would also aggregate to $14.7 million US for those same items?

MR. BRENT SANDERSON: Very close to it, yes.

MR. BOB PETERS: And then supply costs,

Mr. Sanderson, can you explain to the Board what you are trying to depict here under lines 38 down to 47?

MR. BRENT SANDERSON: That's analysis of forecast versus actual costs, where the actual physical commodity itself or the natural gas that customers are burning in their furnaces and hot water heaters and in their businesses and so forth; and so it's basically the volumes of natural gas that customers are either forecast to use or actually did use, at the prevailing market cost or storage cost of those commodity supplies.

I might add, as well, plus any hedging impacts associated with hedging activities on primary gas supplies.

MR. BOB PETERS: Those hedging impacts, Mr. Sanderson, are shown discretely on line 48.

MR. BRENT SANDERSON: Yes, Mr. Peters.

MR. BOB PETERS: All right. The -- back to lines 39 and 40, when you're showing commodity costs and storage gas, why is it that your forecasts were out as much as they were?

MR. BRENT SANDERSON: Again, everything that has to do with variances last fiscal year pretty much have to do with the weather. The weather was so extraordinarily warm that our customers demand for natural gas combined with the very high levels of conservation that we saw, are what drove those negative variances of actual costs relative to forecast costs.

MR. BOB PETERS: Is there a correlation between line 40 and line 39? That is on line 40, you predicted or forecasted zero exchanges with counterparties for primary supply, but you ended up spending $27 million, whereas in the line above that your storage gas, your primary gas in storage was forecast significantly higher than what you actually took into storage.

MR. BRENT SANDERSON: That's a good point, Mr. Peters. You can think, for practical purposes of lines 39 and 40, as theoretically being one and the same. It's just that the costs on line 40 were generated through some capacity management activities of which Mr. Stephens would be in a better position to speak to.

They are fundamentally different from a technical perspective, but it has to do with our primary gas supplies and storage and we had a counterparty deliver us gas in lieu of us taking the gas out of our storage facilities.

So line 40 can be thought of theoretically as was Mr. Stephen's described where we would take some other entities gas off of the TCP bill system and then deliver our gas out of storage to them downstream in

Michigan.

MR. BOB PETERS: Mr. Stephens, on line 40 on schedule 4.0.0, it's referred to as an exchange. But when I flip to Tab 8 in the Book of Documents and go to schedule 4.3.1, it doesn't show up as an exchange on the capacity management schedule does it?

(BRIEF PAUSE)

MR. HOWARD STEPHENS: No, it doesn't.

MR. BOB PETERS: Is that -- can you explain why it doesn't or what the transaction was and how it's different than the exchange revenues shown on schedule 4.3.1.

MR. HOWARD STEPHENS: I think I know the answer, but I just want to make sure. I'd like to consult with Mr. Sanderson for a second.

(BRIEF PAUSE)

MR. HOWARD STEPHENS: I think I can answer your question now.

What you are seeing is the -- there's a cost component to the exchange transaction that we had with one (1) counterpart related to a peaking arrangement. So what we've done is assigned a cost associated with that gas that was delivered to the Manitoba delivery area that would be equivalent to the cost associated with the storage withdrawals that ordinarily would have taken place absent the exchange transaction.

Mr. Kostelnyk is looking at me like I have two (2) heads, so I don't think I got it through.

MR. BOB PETERS: Well, just to help me understand that, is the nature of the exchange transactions different from what's depicted on these two (2) schedules?

MR. HOWARD STEPHENS: This particular transaction, because it was dealing with serving up a portion of our firm shortfall, we've categorized it as somewhat -- something different than the day to day exchanges that we do.

MR. BOB PETERS: It's shown here as another source of gas supply, gas molecule supply.

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: To supply to load, not in excess of capacity.

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: All right. I think I understand your -- your point.

(BRIEF PAUSE)

MR. BOB PETERS: Before the Schedule 4.0.0, at line 48, Mr. Sanderson, and I think also Ms. Stewart in her direct evidence alerted the Board that there was a $47.5 million reduction in the gas cost for Manitobans as a result of the hedging activities in 2005/'06.

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

MR. BOB PETERS: And we'll get into the specifics of that later, Ms. Stewart, but that amount was initially forecast to be $8.9 million according to Schedule 4.0.0.

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

MR. BOB PETERS: And was that a market-to-market view at the last time you came before the Board, or how did you arrive at the $9 million number, do you recall?

(BRIEF PAUSE)

MR. BRENT SANDERSON: Yes. That amount -- none of that would have been settled at that point. That would have been an entirely mark to market position for the hedges that we had in place at March 15th, 2005, which would have covered -- to the best -- would have covered to the end of January 2007 at the time. Pardon me, January 2006.

MR. BOB PETERS: Still with Schedule 4.0.0, on line number 56, we get down to capacity management revenues. And the middle column of 5.746 was reviewed with Mr. Stephens and that was found in -- in Tab 8 of the book of documents.

What's interesting is that it was initially, I think, forecast here at $3.8 million; correct?

MR. HOWARD STEPHENS: That sounds right, yes.

MR. BOB PETERS: And do you recall how you came up with the forecast of $3.8 million?

MR. HOWARD STEPHENS: We used the five (5) year rolling average.

MR. BOB PETERS: Is that, Mr. Sanderson, what you've done for the '06/'07 gas year as well?

MR. BRENT SANDERSON: Yes, sir.

MR. BOB PETERS: To the extent that the rates that the Board approved back in '05/'06 for supplemental gas and non-primary gas costs, that already had embedded in it a credit to consumers of $3.8 million.

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And what you're telling us now, Ms. Derksen, is you made more money than $3.8 million on capacity release, you made $2 million more. And that $2 million more will then be part of the PGVA account?

MS. KELLY DERKSEN: Yes, that's correct. It would be embedded in the $13.2 million that we began refunding on August the 1st.

MR. BOB PETERS: Was there a change, Ms. Derksen, in how the Corporation accounted for its capacity management revenues in the last couple of years?

MS. KELLY DERKSEN: Yes, sir. Previously we would have embedded a forecast of capacity management and included it in the -- the deferral account but we either last year or the year before, my memory's failng me now, we've proposed and the Public Utility Board accepted that we would then include a forecast in base rates as opposed to in the deferral accounts which would then form part of the rate rider.

(BRIEF PAUSE)

MS. KELLY DERKSEN: So -- so I guess what I'm saying to you, Mr. Peters, is that previously we would have refunded it on a retrospective basis as opposed to a prospective basis.

So -- and -- and I'm saying to you is that we are including, in this case, for -- for example, for the '06/'07 fiscal year we have forecasted a -- a credit of $4.5 million in capacity management and revenues that we are already refunding to customers and -- the affects of which are not -- not finalized.

So that extent we are refunding it to them on a prospective basis.

MR. BOB PETERS: And you're putting pressure on Mr. Stephens to go out and find $4.5 million to make sure he lives up to his end of the bargain.

MS. KELLY DERKSEN: Yes, at the direction of the Board we agreed that we would be including it in -- those revenues in base rates.

MR. HOWARD STEPHENS: Mr. Peters, I'll be happy to sell you the gas you use in your home if you want me to make more money.

MR. BOB PETERS: Thank you, Mr. Stephens. Ms. -- Ms. Derksen, that -- including that forecast revenue is I suppose analogous to including in rates forecast costs, would you agree?

MS. KELLY DERKSEN: I believe that's the concern that the Public Utilities Board had at the time that this issue was raised a couple of years ago so with respect to that concern, this is how we proposed to treat it and the Public Utilities Board ultimately accepted.

MR. BOB PETERS: Thank you. Mr. Stephens, just to maybe look at your report card for the last few years, at Tab 9 of the book of documents are extracts from PUB/Centra Information Request 14A and there's Attachments 1, 2, 3, 4, and 5 of 5. Maybe for my questions we can just jump to 5 of 5.

(BRIEF PAUSE)

MR. HOWARD STEPHENS: I have it.

MR. BOB PETERS: And on PUB/Centra 14A Attachment 5 of 5 what you're depicting here for the Board is those fixed demand charges that Mr. Sanderson and you spoke to the Board about just a few minutes ago, together with how much of those demand charges you ended up actually utilizing. Would I have that correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And if I look to the bottom right-hand corner of the Attachment 5 of 5 to PUB/Centra 14A it shows ninety-nine thousand two hundred and sixty dollars ($99,260).

What does that represent, sir?

MR. HOWARD STEPHENS: It's the difference between the amounts on -- the total amount on line 9 subtracting -- subtracting the line -- the amount on line 20.

MR. BOB PETERS: All right. I appreciate the math but the -- does it depict -- does it --

MR. HOWARD STEPHENS: It's one way to answer the question.

MR. BOB PETERS: I'll rephrase the question. Does that also show the Board that Centra paid a hundred thousand dollars ($100,000) for capacity that it couldn't utilize or couldn't sell?

MR. HOWARD STEPHENS: Well, that's essentially it, that we -- out of the $24.5 million of the capacity that we purchased there was a hundred thousand bucks ($100,000) worth of capacity that we didn't -- weren't able to utilize.

MR. BOB PETERS: So you left a hundred thousand dollars ($100,000) on the table and all consumers will end up paying a share of that through the distribution rate?

MR. HOWARD STEPHENS: Well, they're going to pay the fixed demand charges as we've -- we've experienced them so I haven't left anything on the table, sir.

MR. BOB PETERS: It was perhaps a poor

choice of words then, Mr. Stewart -- Mr. -- sorry, Mr. Stephens.

But there was a hundred thousand dollars ($100,000) of demand charges that you couldn't bundle or sell to any third party?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And I'm not suggesting it was through lack of effort, but that's how much was the take or pay side of the equation that we had to pay for that we didn't take any advantage of?

MR. HOWARD STEPHENS: That's correct. But, I mean and I would -- I'm not going to let you get away with just -- I mean a simple yes or no on that.

I mean if you look at the relative magnitude, in terms of a hundred thousand dollars ($100,000) out of $25.5 million dollars I think that's a pretty good end result.

MR. BOB PETERS: Is that the Canadian side of the operations?

MR. HOWARD STEPHENS: This is TCPL demand charges, yeah.

MR. BOB PETERS: And what would it be if we also looked at the US side of the operations?

MR. HOWARD STEPHENS: Well, it depends on when you ask me about.

MR. BOB PETERS: Well for '05/'06?

MR. HOWARD STEPHENS: For '05/'06? Actually not too bad, we were able to offload some of that capacity and recover some revenues. Traditionally that capacity has not been that lucrative in terms of -- simply because of the way we've contracted it.

It's contracted simply from the Oklahoma basin in the case of the southwest capacity to storage and our storage only. And we get a discounted rate associated that with. If we try to divert it elsewhere then we go to the max tolls right away and it takes us out the money and it becomes very much less attractive in terms of trying to sell on a secondary market.

MR. BOB PETERS: Can you quantify for the Board, what in 2005/'06 was the unutilized demand charges on the American side of the operation?

MR. HOWARD STEPHENS: I remember seeing the number in one of the IR's, but I don't recall right now off the top of my head.

MR. BOB PETERS: In the event I don't find it, I'll come back and ask you for it. But, I -- I didn't make a note of it either. So we'll check that.

In terms of the seventh document in the Book of Documents, it's a copy of -- sorry in Tab 7, there's also document number -- schedule 4.1.0 and it's a summary of all gas cost deferral balances.

Mr. Sanderson, do you have that?

MR. BRENT SANDERSON: Yes, I do.

MR. BOB PETERS: So these deferral account balances are not shown on the previous page, schedule 4.0.0 because these ended up in a PGVA, a purchase gas variance account, or some other deferral account, would that be correct?

MR. BRENT SANDERSON: What's depicted on schedule 4.1.0 is the fiscal year-end balances in a number of different gas cost deferral accounts, which ultimately were all rolled into a single prior period deferral account at July 31st, 2006.

With the exception of the primary gas, PGVA balance on line 17, which is just noted as an item of interest, but is not particularly relevant here as it relates to the non-primary gas cost deferrals.

MR. BOB PETERS: Well, let's just run down these very quickly then, Mr. Sanderson.

On line 2, the prior period gas deferrals would represent the sum balance of the PGVA's and gas deferrals prior to 2005/'06?

MR. BRENT SANDERSON: It represents what's leftover of the amounts that we were refunding in rate riders over the period July -- August 1st, 2005 through July 31st, 2006.

And those amounts were under-refunded or we didn't refund the full amount that we would have forecast to refund over that period because of the warm winter again and the declining customer utilization or customer consumption.

MR. BOB PETERS: So you still have five hundred and eighty-eight thousand dollars ($588,000) left to refund?

MR. BRENT SANDERSON: We did at July 31st, 2006, yes.

MR. BOB PETERS: And then in terms of the 2005/'06 balances, those specifically relate to the supplemental gas transportation and distribution and that would be numbers that we would have found on Tab 2 of the Book of Documents from your schedule 5.2.4?

MR. BRENT SANDERSON: The line items are the same, but they relate to different fiscal periods. The schedule 5.2.4 in Tab 2 of the Book of Documents relates to the forecast period 2006/2007, whereas the amounts on 4.1.0 relate to the '05/'06 fiscal period.

MR. BOB PETERS: Right. Thank you. I had the wrong year. The heating value margin deferral, can you explain that to the Board?

MR. BRENT SANDERSON: Yes, I can. We

buy natural gas per unit of heat content. We buy it on the basis of dollars per unit of energy. Customers are billed, however, on unit of volume; that's, to the best of my understanding, the most cost-effective way to meter customers is based on the amount of flowing gas through their meter.

To the extent that the heating content of the gas per given unit of volume is less than that embedded in the forecast, a customer would have to use more or buy more gas from us to provide a given level of heating for whatever application they were using it, being in their furnace or their hot water heater or what have you.

So what we do is -- is every month we calculate the difference between the heating content of the gas embedded in the forecast and what was actually delivered to customers and we calculate how much additional margin the utility earned on that excess sale of gas, if you will.

Or if it's a greater heating content we would move less gas than forecast, but generally it tends -- it is tended to be a lesser heating content on an actual basis than the forecast necessitating a customer needing to take more gas to provide a given level of heating.

And we defer those amounts, set them up in a deferral account, calculate interest on those and then bring them forward to a proceeding such as this to ensure that those amounts, in this case it's an amount owing to customers, to ensure that that's refunded to customers to make them whole at the end of the day on the difference between what they were paying -- the volume they were paying for and the energy that they received as a result of what flowed through their meter.

If that didn't clarify it adequately, let me know and I'll try and characterize it from a different perspective.

MR. BOB PETERS: Why is it that you buy gas based on heat content as opposed to volumetric measurement?

MR. BRENT SANDERSON: Mr. Stephens may want to jump in and -- and correct me or clarify on this, but it's -- for want of a better term, it's the -- it's the way the industry is structured and it's -- we don't -- I'm sure that suppliers and utilities don't want to be in the situation of having to calculate heating value deferral accounts between them.

And the technology is -- is there to allow pipelines and natural gas suppliers and utilities to transact on the basis of energy as opposed to volume, but the cost to calculate customers' gas takes on the basis of actual energy would be cost prohibitive if you were to extend that to the individual homeowner, all two hundred and fifty-five thousand (255,000) customers that we have here in Manitoba.

MR. BOB PETERS: And so you sell it volumetrically even though you purchase it by heat content?

MR. BRENT SANDERSON: Yes. I would say by necessity.

MR. BOB PETERS: All right. And on lines 12 and 13 of Schedule 4.1.0, this may be what Ms. Derksen was trying to explain to me that I didn't understand before lunch.

Can you explain why the same deferral account item has these -- has these various charges against it?

MR. BRENT SANDERSON: Now that I look at the schedule and I think about what you had asked me earlier, I think -- I think I need to correct a bit of what I said.

When looking at line 2, the balance in what we call the July 31st, 2005 prior period gas deferrals account, that five hundred and eighty-eight thousand dollar ($588,000) balance owing to customers is actually as at March 31st, 2006, the end of our previous fiscal year.

(BRIEF PAUSE)

MR. BRENT SANDERSON: And so all of those respective balances are all totalled to line 10 to indicate a sum balance in all of these various deferral accounts at the end of our prior fiscal year, March 31st, 2006.

Then lines 12 and 13 carry those balances forward to July 31st, 2006, which is the day immediately preceding the implementation date we had requested to implement the new refunding riders.

So those riders refunding what was five hundred and eighty-eight thousand dollars ($588,000) owing to customers at July -- at March 31st, 2006, those riders would have continued refunding those amounts from the past years to customers for the months of April through July of 2006, and that would have been the ninety-eight thousand six hundred and fifteen dollars ($98,615) of the continuing refunding to customers through to the expiration of those rate riders on July 31st, 2006.

And then line 13 is the carrying costs on all of the various deferral accounts that we're talking about on this schedule, between April 1st, 2006 and July 31st, 2006, which brings us to our July 31st, 2006 sum total balance of $13.186 million owing to customers on July 31st, 2006, the day immediately preceding our requested implementation of these new refunding riders to refund those amounts to customers over August 2006 through July 2007.

MR. BOB PETERS: Thank you, Mr. Sanderson. Did I understand correctly that then line 13 carrying costs shown are on all of the -- all of the deferral account balances shown above line 13 for the -- from March 31 to July 31?

MR. BRENT SANDERSON: Yes, that's correct. On the '05/'06 supplemental transportation and distribution PGVAs the heating value margin deferral and what's shown on line 2 as the July 31st, 2005, prior period gas deferrals account; that's the sum total of the carrying costs on all those accounts over that period.

MR. BOB PETERS: And this $13.2 million of total deferral cost balances is being refunded in the interim rates by way of a rate rider?

MS. KELLY DERKSEN: Many rate riders, but yes.

MR. BOB PETERS: And it's being refunded

over what time period, Ms. Derksen?

MS. KELLY DERKSEN: A twelve month period beginning August 1st of 2006 and set to expire July 31st of 2007.

(BRIEF PAUSE)

MR. BOB PETERS: I'd like to turn with the Panel to a forecast for the 2006/'07 gas costs and in terms of that forecast is the first step in that forecast the estimation of the number of customers by class?

MR. BRENT SANDERSON: I would say it's a little more comprehensive. The first step, it would involve forecasting customers and their consumption over the forecast period and it would -- the -- the different processes dovetail with one another and there's a bit of circularity to it so the load and customer forecasts would be the first start -- first starting point, yes.

MR. BOB PETERS: Mr. Sanderson, in Tab 12 of the book of documents the second page in is an extract from PUB/Centra 17C, Attachment 1 and there's also Attachments 2 and 3 included but these attachments represent your forecast for different customer classes -- classes as well as the volumes for those customers in those classes. Have I that correct?

MR. BRENT SANDERSON: No, I don't believe that you do. I -- what these schedules represent is the differences that took place in prior periods between forecast and actual figures for five (5) fiscal periods going back to the 2001/2002 fiscal period. There's no figures represented in here for the 2006/2007 gas cost forecast.

MR. BOB PETERS: I appreciate that. The -- the actual customers and the actual volumes, though, are -- are current and would be a starting point to working forward for the '06/'07 forecast?

MR. BRENT SANDERSON: Past actual numbers of customers and consumption would be one (1) of the starting points to developing a -- a prospective customer and load forecast, yes.

MR. BOB PETERS: And in terms of developing the numbers in the load forecast, that takes place through some regression analysis that's done?

MR. BRENT SANDERSON: Regression analysis is one (1) of the mathematical tools that's used.

MR. BOB PETERS: It appeared in the materials, Mr. Sanderson, that you aggregated the SGS commercial class with the LGS class when you were doing your forecasts; is that what you did?

MR. BRENT SANDERSON: Yes, aggregated

historical data to -- to provide a common baseline historically. There was a necessity to do that because Centra has undertaken over the past number of years to review the customers that populate those classes to ensure that respective customers in -- in a rate class that's the most economically beneficial to them.

And that has necessitated Centra approaching a number of customers asking if they would like to move classes to be in a more economically advantageous class to them and there's been some fairly significant migrations between those two (2) classes that tends to have a significant effect on the profile of the typical customer in each of those classes.

So there was a need to aggregate them in reviewing their historical data and developing a prospective forecast for those customers in those classes.

MR. BOB PETERS: So you treated them as if they were the same customer class but then you went back and you then dis-aggreqated them, it looks like in your materials.

MR. BRENT SANDERSON: The starting point would be to develop a forecast for those two (2) classes in aggregate and then based on expectations for the relative population of those respective classes, then it would be dis-aggregated in -- in developing the perspective forecast.

MR. BOB PETERS: Mr. Sanderson, before we leave the Tab 12 and the PUB/CENTRA-17-C, Attachment 1, are the variances that are shown here depicting on how far off of forecast Centra has been in -- in the prior years?

So for the '05/'06 year you have actually two hundred and thirty thousand nine hundred and seventy-eight (230,978) customers and you were off in your forecast by the decimal -- 0.10 percent.

MR. BRENT SANDERSON: Yes. That forecast relative to -- that actual figure relative to the most recent forecast for that period.

MR. BOB PETERS: Can you tell the Board whether your forecasts are becoming more or less accurate through all these methodology changes?

MR. BRENT SANDERSON: As it pertains specifically to the number of customers that we're forecasting, if you -- if you look at the table at the bottom, yes, the numbers indicate that the trend is towards a more accurate customer forecast. Yes.

MR. BOB PETERS: Can you say the same for the volume forecast?

MR. BRENT SANDERSON: Well, to paraphrase

Mr. Stephens, not wanting to -- for us to take the blame in that regard, with all of the various things that are going on in the natural gas markets as it pertains to demand side management, publicity that surrounds temporarily high gas prices in the wake of two (2) once in a hundred (100) year hurricanes, like that, which occurred last fall, and the top of my topomine (phonetic) nature of energy efficiency, it's something that's very, very hard to predict.

And so it's introduced a significant element of uncertainty in the load forecasting process because there's so many fundamental changes going on in the underlying market that will take time to sort of percolate to the surface, if you will, so that we can get a firmer handle on what we can expect going forward for the long term.

MR. BOB PETERS: For the customer classes for the higher consumption customers, Mr. Sanderson, the Corporation actually consults with them before it gives a forecast on volumes, is that correct?

MR. BRENT SANDERSON: Our customer service and marketing people, our key and major account representatives touch base in person with the majority of those hundred and fifty (150) to a hundred and sixty (160) large customers that we classify as industrial.

MR. BOB PETERS: And when you touch base with them you ask whether they're going to use the same amount of gas as last year or more or less?

MR. BRENT SANDERSON: Among other things we ask what their expected production levels are going to be, if they have any plans to expand their facilities, change-out equipment with higher efficiency equipment, add another shift; all those type of things that could have an effect on their gas production. And to the -- and they share that information with us to the extent that they feel able.

And -- and then the difference between what they've instructed us to expect and what actually happens can depend on a myriad of factors, but we make our best efforts to get a very tight handle on what they expect to go on in their operations as it relates to gas usage.

MR. BOB PETERS: Once you have those various volumes, Mr. Sanderson, you would aggregate them and that would provide you with your estimate of your annual sales?

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

MR. BOB PETERS: And then to that you would also add a component for this unaccounted-for gas that we've talked about?

MR. BRENT SANDERSON: That part of the process would come after the customer and load forecasting process, that would be the next step in -- in a chain of activities, that would be developing our purchased gas cost forecast.

We would look at given -- our expectations for customer -- customer gas utilization in a normal weather year, then we look at that combined with our expectations of what the unaccounted-for would be and then develop that into what we would need to buy to ensure that we have adequate gas to supply customers' forecast needs.

MR. BOB PETERS: And that UFG component that's added is the 0.9 percent you mentioned to the Board earlier?

MR. BRENT SANDERSON: It's been relatively stable for the past few years and yes, it continues to be 0.9 percent in our forecast.

MR. BOB PETERS: Mr. Sanderson, at Tab 11 of the Book of Documents, there's an extract from PUB/Centra 12 and there's a table attached to it, if you could turn to that attachment.

Can you explain to the Board what the -- what is being depicted there in terms of UFG volumes and then why are there UFG true-up volumes also shown?

MR. BRENT SANDERSON: We measure our actual and accounted for gas experienced over a period that is a little bit out of sync with our fiscal period or the gas year period.

We choose a period over which to true-up that factor. We want to end in a period where system volumes tend to be at their most stable and at a lower ebb, so that any inherent embedded error in the number would have the least impact over the course of the entire annual period.

So we true -- true those figures up based on the June to May period. And then what we do is, during the course of a year beginning at the month of June which would be the beginning of our unaccounted for gas year, we deduct from our system receipts the assumed percentage of unaccounted for gas embedded in our forecast which would be 0.9 percent, in this case.

And then what we do, is at the end of the annual period, we compare our actual system receipts with our total calendar utilization by our customers, which by necessity must be an estimate, as well because we bill our customers on a cyclic basis and, in any given point in time, we have no way of knowing with absolutely certainty exactly how many molecules of gas our customers took over a period.

And so we compare what our actual system receipts were with our absolutely best estimate of what our physical takes by our customers were over that same period, and then we get our actual unaccounted for gas over that period.

We compare that amount to the amount that we've been deducting from our receipts over that same period, based on our forecast assumption that being the 0.9 percent, and to the extent that there's any difference, we go back and allocate that to all the months during the period costed out at the respective prevailing purchase gas costs we experience during that period.

And it may be an additional amount flowing from the primary and supplemental gas PGVA's to the distribution PGVA in that we may have experienced more unaccounted for gas than forecast, and it can go the other way, as well.

And so what this schedule is showing is for each of the months the amount we assumed to be unaccounted for gas based on our forecast and you'll see in June of each year, you'll see an additional two lines that show the financial impacts of our unaccounted for gas true-up, which I've just described.

MR. BOB PETERS: All right. Thank you for that clarification, Mr. Sanderson.

So if we turn to Tab 13 of the Book of Documents and look at schedule 5.2.3(b), what you've got before the Board is the forecast for '06/'07 non-primary gas costs as well as some primary gas forecasts in there.

And that is the amount on which Board Order 116/'06 was based?

MS. KELLY DERKSEN: Can you clarify the schedule number, Mr. Peters?

MR. BOB PETERS: If it's Tab 12, I think in the Book of Documents, Ms. Derksen, and it's schedule 5.2.3(b).

MR. BRENT SANDERSON: We've got that schedule now.

MR. BOB PETERS: I apologize I'm told I mis-spoke again.

In terms of the schedule Mr. Sanderson, this is the same information on which your interim application was made to the Board that resulted in Order 116/'06?

MR. BRENT SANDERSON: With respect to our base supplemental primary -- supplemental transportation distribution base rates that became effective August 1st of this year, yes.

(BRIEF PAUSE)

MR. BOB PETERS: In the -- in the materials -- in the numbers that are on schedule 5.2.3B(b), some of those numbers will now have changed as they relate to primary gas, would that be correct?

MR. BRENT SANDERSON: Yes, and those would have been reflected in subsequent applications for primary gas rates that we would bring forward to the Board for the first of each gas quarter.

MR. BOB PETERS: And you'd agree then that they're also subject to changing the next gas quarters as well?

MR. BRENT SANDERSON: And each and every one after that, yes.

MR. BOB PETERS: And in terms of the capacity management number, it's the second line from the bottom, Forecast Capacity Management Revenues, this $4.5 million is already an amount that you are imbedding in the interim rates based on a rolling five (5) year average of capacity management?

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

MR. BOB PETERS: Ms. Stewart, and we will not forget her and talk with her yet about hedging matters, but in her evidence today she suggested that there was a certain amount that had already been fixed or crystallized in terms of hedging impacts for the '06/'07 budget year. Those amounts aren't reflected in here; is that correct?

MR. BRENT SANDERSON: There would have been two (2) months of crystallized hedging impacts imbedded in this forecast at the time it was prepared, that being the months of April and May of 2006.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Sanderson, also in this forecast on Schedule 5.2.3B it was premised on a May 1st, 2006 forward price strip, correct?

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: And that was a point in time that was selected by the Company and the application was based on it and every day since then the numbers would change?

MR. BRENT SANDERSON: In the overall gas cost forecast I would agree. I'd just like to point out with respect to the base rates for supplemental transportation and distribution rates that are the subject of this hearing, those costs would not be subject to any material variability as a result of the changes in the prevailing or futures market prices for natural gas.

MR. BOB PETERS: You already told the Board, Mr. Sanderson, that the UFG percentage used was 0.9 percent, correct?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: These numbers also assume a small TCPL toll reduction?

(BRIEF PAUSE)

MR. BRENT SANDERSON: I'm just looking for a document here, Mr. Peters, if you could just bear with me for a moment?

MR. BOB PETERS: Certainly.

(BRIEF PAUSE)

THE CHAIRPERSON: Mr. Peters, let us know when you think it's time to have a bit of a break.

MR. BRENT SANDERSON: I have that answer for you, Mr. Peters. All of the TCPL toll reductions that were itemized in Mr. Stephens' examination-in-chief are all reflected in the numbers on the schedule to which you refer.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: And you can also confirm then that the ANR and the Great Lakes gas transmission tolls remain unchanged?

MR. BRENT SANDERSON: Yes, sir.

MR. BOB PETERS: And the primary gas as per the Nexen contract, pricing has remained unchanged?

MR. BRENT SANDERSON: Do you mean the terms of the price -- determination of the price under that contract?

MR. BOB PETERS: Yes, sir.

MR. BRENT SANDERSON: Yes, correct, sir.

MR. BOB PETERS: And in terms of the US supply, that is indexed to the NYMEX futures strip and was done on the May 1st, 2006 strip taken there as well?

MR. BRENT SANDERSON: It's -- it's -- the pricing is -- the basis of the price forecast originates with the NYMEX but we also incorporate a basis -- a forward basis to reflect the difference in price between Henry Hubb in Louisiana and the delivery point at which we would take that US gas into those contracts.

So just to be clear it's not a pure NYMEX/Henry Hubb price; it's a NYMEX/Henry Hubb price with a -- with a basis differential.

MR. BOB PETERS: Maybe I'll just slow you down here and have you explain to the Board what this basis differential is notionally to accomplish.

MR. BRENT SANDERSON: What a basis differential is, is it's the market value -- it's -- it's meant to signify essentially the market value of transportation to move gas from one delivery point to another.

A NYMEX, when you hear a NYMEX index or a NYMEX future's price quoted that's -- that's the US equivalent of ACO (phonetic) for Alberta gas and it's basically supposed to be the benchmark that indicates the market value of natural gas in the United States. And then prices for the commodity at different points away from there will be somewhat different because there's a cost to move the gas from that point to any other delivery point.

So to the extent that we expect to take gas at the Oklahoma head station, for example, to transport it on our -- in our southwest, we can't just use a NYMEX price because our delivered price will have to be higher because any supplier who's supplying us with that gas will have to pay to move that gas.

And so the most objective measure by which to determine the cost of that transportation is to look at the -- the basis futures which is the prevailing market price that the market is paying for transportation between those two (2) points.

MR. BOB PETERS: Thank you, Mr. Sanderson.

The storage withdrawals that are reflected in the numbers of Schedule 5.2.3, what you anticipate here is you've taken the actual balances after 2005/'06 and then you've put in the projected summer 2006 injection costs?

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

MR. BOB PETERS: And in terms of delivered service, that would be also NYMEX-based plus the differential that you spoke of?

MR. BRENT SANDERSON: Yes. In this case it would be a NYMEX future's index -- or future's price with a -- a NYMEX Michigan head station basis differential, because that's where -- that's the most appropriate proxy for delivery point for our delivered services, in the majority of cases.

MR. BOB PETERS: The exchange rate that was utilized in this application was one dollar and twenty-three cents ($1.23)?

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

MR. BOB PETERS: And how did that change from the previous year?

MR. BRENT SANDERSON: You'll just have to give me a moment, Mr. Peters, I have to find the reference.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Sanderson, maybe while you're just checking that, I wonder if I could impose on Mr. Warden to look in his crystal ball and tell the Board what he thinks the US exchange rate will be -- well, is currently and will be for the -- for the balance of the '06/'07 year.

MR. VINCE WARDEN: Well, it's currently about one nineteen (1.19) and -- well, we're actually a little better than that. I don't see it -- I think we're using -- in our financial forecast I think we're using one twenty (1.20) as the exchange rate going forward.

MR. BOB PETERS: Mr. Sanderson, I might just let you look for that at the break, but would -- would the exchange rate dropping from one dollar and twenty-three cents ($1.23) down to a dollar nineteen

($1.19) prove beneficial to Manitoba customers a year from now?

MR. BRENT SANDERSON: Yes, it would.

MR. BOB PETERS: And that would be reflected in the amount of monies that are captured in the PGVA accounts?

MR. BRENT SANDERSON: Correct, sir.

--- UNDERTAKING NO. 2: Mr. Sanderson to advise: The exchange rate that was utilized in this application was one dollar and twenty-three cents ($1.23), how did that change from the previous year.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: You've told us that the forecast gas costs have $30.5 million imbedded in it as the estimated impacts of hedging and that is $30.5 million of additional costs; correct?

MR. BRENT SANDERSON: As of the preparation of this forecast, correct.

MR. BOB PETERS: And even though Ms. Stewart told the Board how much had actually settled to date, that still is not an indication as to what the final number will necessarily be, is it?

MS. LORI STEWART: Yes, that's correct. A number of our positions are as yet -- a number of our 2006/'07 positions are as yet unsettled.

MR. BOB PETERS: Ms. Stewart, while you have the microphone maybe we can just flip to Tab 27. And Tab 27 contains a -- a copy of Schedule 6.3.1, which is the mark to market calculation on which the interim application to the Board was based.

Would that be correct?

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

(BRIEF PAUSE)

MR. BOB PETERS: We're busy debating whether it's 5.3.1 or 6.3.1 and we'll --

MS. LORI STEWART: I believe it is 5.3.1.

MR. BOB PETERS: Right. And Ms. Stewart if you turn the page in Tab 27, you'll see an answer that you provided the Board -- excuse me -- an answer that you provided the Board to PUB Information Request of Centra number 43, and attachment 1(e).

And 1(e) was another snapshot in time and it shows that the mark to market results are $77 million unfavourable, would that be fair?

MS. LORI STEWART: Yes, that's correct, noting that some of those positions had not yet settled.

MR. BOB PETERS: And you say that, Ms. Stewart, because until they're settled you don't know if they will settle more favourably or less favourably than what's shown on the schedule?

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

MR. BOB PETERS: But regardless of what has been settled to date, the Corporation is not changing the application that it made for the interim rate approvals that resulted in Order 116/'06?

(BRIEF PAUSE)

MS. KELLY DERKSEN: Mr. Peters, I just wanted to clarify for the record, hedging impacts don't flow through to supplemental transportation or distribution rates.

So we would really be speaking to Order 144 of '06, which recently approved our November 1 primary gas application, and we are not seeking a change to it.

MR. BOB PETERS: And as of November 1, Ms. Stewart, do you recall what the -- what the settled positions were on the hedges for the -- for the year?

MS. LORI STEWART: Following the close or the settlement of the month of November 2006, actual realized results to the end of November -- to November 30th, 2006; are an addition to customer's gas costs of $42.3 million.

(BRIEF PAUSE)

MR. BOB PETERS: All right. Then just to conclude and maybe summarize what we've been -- gone over, the 2005/'06 total gas costs you've shown as at Tab 7 of the Book of Documents and schedule 4.0.0, $389.7 million and that's your request for approval, is that correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And of that amount the hedging results were $47.5 million as a reduction in gas costs?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And the total non-primary gas costs that were in rates would have been this $68.9 million shown on schedule 5.2.4 in Tab 2 of the Book of Documents?

MS. KELLY DERKSEN: What we're showing on schedule 5.2.4 at $68.9 million is -- was not embedded in rates. It is weigh COG applied against weighted average cost of gas for that year applied at the '06/'07 forecast of volumes and demand and so forth.

So those two (2) numbers are not the same, Mr. Peters.

MR. BOB PETERS: All right. Thank you for that. What is the result though, is that for '05/'06 there has been a surplus of monies in the PGVA that will be refunded in the amount of 13.2 which reflects the revenues received over the costs charged for the non-primary gas items?

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

MR. BOB PETERS: And for the 2006/'07 year at Tab 12 and that schedule 5.2.3, the total forecast gas costs are shown there at $482 million, but that doesn't reflect the latest view of primary gas, does it?

MR. BRENT SANDERSON: No, it does not.

MR. BOB PETERS: But it does contain the latest forecast for non-primary gas which is the $62.4 million.

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: Mr. Chairman, I will move onto a new area about how that $62.4 million is going to be paid after the break, if that suits the Board?

THE CHAIRPERSON: Very good. Thank you. We'll be back just before 3:00.

--- Upon recessing at 2:44 p.m.
--- Upon resuming at 3:03 p.m.

THE CHAIRPERSON: Okay, Mr. Peters...?

MR. BOB PETERS: Thank you Mr. Chairman.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Mr. Sanderson, you took away a short request to figure out what was the foreign exchange rate that was embedded in the 2005/'06 forecast for the non-primary gas cost rates.

What was that number?

MR. BRENT SANDERSON: Yes, that was a dollar twenty-three ($1.23) sir.

MR. BOB PETERS: Do you know what it settled out at, in terms of actual?

MR. BRENT SANDERSON: In terms of our purchases of services and supply from the US, a dollar nineteen ($1.19).

MR. BOB PETERS: Thank you. Before the

break, Ms. Derksen, Mr. Sanderson confirmed that the total non-primary gas costs that he wanted approval for were the $62.4 million.

And I take it, it's now your responsibility to figure out which customer classes pay how much of that?

MS. KELLY DERKSEN: Yes, it is.

MR. BOB PETERS: And at the book of documents, Tab 13, you've provided the Board with some insight as to how the functionally classified non-primary gas costs have been allocated, correct?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: Can you just briefly explain to the Board how you -- the mechanical steps you went through to do that?

MS. KELLY DERKSEN: As in previous years and consistent with what we've presented in our application, the first step that I go through is to functionalise costs and that means to put them in the broadly defined categories of production, pipeline storage, transmission, distribution and onsite.

So I take all of the 62.4 million that we have requested approval of from the Public Utilities Board and functionalised them into one (1) of those six (6) categories.

As the case might be for this smaller type of application, those costs only fit into production, pipeline storage and transmission in this case. I would then classify costs and to classify costs, means to determine the variability and how those costs are influenced, what drives those costs.

And the third step then is -- once I've figured out how they're functionalised and how -- the basis of variability, I'm then able to allocate them to each of the customer classes.

MR. BOB PETERS: The commodity component is based on class volumes, would that be correct?

MS. KELLY DERKSEN: It really depends on which commodity component that you're referring to. If it was primary gas, for example, we would accumulate all of the forecasted volumes that we expect to sell to each of the customers that take our primary service and divide total cost by that volume.

MR. BOB PETERS: Then can you explain how the capacity components are allocated to the customer classes?

MS. KELLY DERKSEN: Capacity costs are allocated on a peak and average basis, which assigns cost responsibility on that classes contribution to peak day, as well as, average use of the system.

MR. BOB PETERS: Is the methodology you've used and shown here on -- in Tab 13 in your response to PUB/Centra 30, consistent and the same as the methodology that you've used last time?

MS. KELLY DERKSEN: Yes, it is, sir.

(BRIEF PAUSE)

MR. BOB PETERS: When we look at the rate schedules and customer impacts from the application, let's just remind ourselves, Ms. Derksen, there are really no rate changes that are being sought as a result of the application before the Board, that's correct?

MS. KELLY DERKSEN: Yes sir.

MR. BOB PETERS: But, what happened in the interim application was that there was -- in the case of base rates for non-primary gas, a decrease in aggregate of $6.6 million?

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

MR. BOB PETERS: And we saw that in the book of documents, the second tab, Schedule 5.2.4.

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: Mr. Sanderson, did -- did we yet uncover the mystery as to why the distribution -- and I know it's not a mystery, but the distribution rate was going to increase by eight hundred and thirty-seven thousand dollars ($837,000)?

Did you look at that further?

MR. BRENT SANDERSON: I was -- I wasn't clear that you were expecting me to undertake to do that but I can do that if that's what you'd like.

MR. BOB PETERS: If you would, please, I think that would help complete the record for the Board.

MR. BRENT SANDERSON: Yes, sir.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Ms. Derksen, the -- the base rates that we've talked about are the rates that are based on the forecasted costs and do not take into account any deferral account balances or PGVA balances, is that correct?

MS. KELLY DERKSEN: Yes, it is.

MR. BOB PETERS: And the base rates that this Board approves are not necessarily, and some would say seldomly, are the billed rates to consumers.

MS. KELLY DERKSEN: Probably a fair statement, Mr. Peters, yes.

MR. BOB PETERS: And that -- what that means is that usually added on to the billed rate or subtracted from the billed rate is a rate rider or -- or multiple rate riders.

MS. KELLY DERKSEN: Yes, sir.

(BRIEF PAUSE)

MR. BOB PETERS: In terms of the base rates that went into effect on August the 1st of 2006 in the Interim Order 116 of '06, those base rates are designed to recover the $62.3 million of non-primary gas costs?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And at the same time as those rates were established there was a rate rider that was coming off, is that also correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And can you explain to the Board what that rate rider that came off was to accomplish?

MS. KELLY DERKSEN: The rate riders that fell off on July 31st of 2006 reflected past accumulations in the PGVA accounts for supplemental, transportation, and distribution, and those were a result of the 2006 -- sorry, excuse me -- 2005/'06 and 2006/'07 General Rate Application and they were in effect for a twelve (12) month period and fell off; that means they came off of the rate, the -- the billed rate effective August 1st of 2006.

MR. BOB PETERS: And those prior rate -- the prior rate rider that came off had not as you've shown the Board in Schedule 4.1.0 in Tab 7 of the book of documents, it had not fully refunded the amount of money that you had expected it to refund for a variety of reasons?

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

MR. BOB PETERS: And one (1) of the variety of reasons would include that the meters weren't spinning as much in Manitoba because the weather was warmer than normal.

MS. KELLY DERKSEN: A very good possibility, yes.

MR. BOB PETERS: All right. And so there was a balance yet to be refunded and that balance that didn't get refunded you've now added that into the new rate rider that's on the interim rates today?

MS. KELLY DERKSEN: Yes, I have, yes.

(BRIEF PAUSE)

MR. BOB PETERS: Just a point of clarification with you, Ms. Derksen, in -- in terms of what are the prior year PGVA balances, I think we have a document showing that there's about four hundred and ninety-eight thousand dollars ($498,000) included in that -- in that amount; are you familiar with that?

MS. KELLY DERKSEN: I am. That's actually reflected in Schedule 7.4.0 --

MR. BOB PETERS: And --

MS. KELLY DERKSEN: -- of our filing.

MR. BOB PETERS: And that's found at Tab 14 of the book of documents, although it may not be as legible there as elsewhere.

But, Ms. Derksen, this four hundred and ninety-eight thousand dollars ($498,000) that's on that schedule is not shown on Schedule 4.1.0 in that amount unless you net off line 2 from line 12 that Mr. Sanderson and I went through.

Have I got that right?

MS. KELLY DERKSEN: Yes, you're correct.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, you show on Schedule 7.4.3 the $13.2 million total of deferral accounts and PGVA account balances to be refunded, can you confirm to the Board that those are going to be refunded to customer classes on the same basis as the $62 million non-primary gas costs were -- are charged to them?

MS. KELLY DERKSEN: Yes. I go through the exact same process, Mr. Peters, to re-allocate the costs that were incurred during that fiscal period, which end up resulting in an amount of $13.2 million outstanding to be owed to customers. I allocate costs in exactly the same manner as I do for base rates.

MR. BOB PETERS: Now, you mentioned it I believe in your direct evidence through Ms. Murphy, but when you add a rate rider to some components of non-primary gas it's not quite as straightforward as one would have thought, because the supplemental gas rate rider really doesn't get added to the supplemental gas rate for most customers.

MS. KELLY DERKSEN: For all customer classes, yes, that's correct. As per Board Order 131 of '04, Centra had at that time proposed that we not recover or refund any PGVA amounts on account of supplement gas in the supplemental rate, and we had proposed that they be recovered or refunded through the distribution rate.

And we have done so in this application, consistent with what we have done in the past General Rate Application, with the exception of the main line and the interruptible customer classes.

MR. BOB PETERS: Thank you for settling that argument. So in terms of all -- all customers, it's all with the exception of interruptible and main line?

MS. KELLY DERKSEN: All customers have their supplemental PGVA refunded to the distribution rate with the exception of main line and interruptible.

MR. BOB PETERS: And in terms of the special-contract customer, that special contract-customer share of the $13.2 million is mostly through the heating value deferral account, is it not?

MS. KELLY DERKSEN: In this application it is indeed, Mr. Peters.

MR. BOB PETERS: And that's seen on Schedule 7.4.0, albeit not all that clearly, but it's -- it's demonstrated that about two hundred and twenty thousand dollars ($220,000) is owing as a result of heating value deferral.

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

MR. BOB PETERS: And you have reached an agreement to pay off this customer's balance owing in a lump sum and probably have in fact already done so.

MS. KELLY DERKSEN: We have done so already, yes, Mr. Peters.

MR. BOB PETERS: And the amount you paid

was the two hundred and seventy-three thousand dollar ($273,000) total figure, as shown on 7.4.0?

MS. KELLY DERKSEN: Yes, sir.

MR. BRENT SANDERSON: Mr. Peters, not wanting to interrupt your line of questioning, I do have the response to that undertaking that we discussed a moment ago anytime you're ready to hear it.

MR. BOB PETERS: Well, let's -- let's hear it now.

MR. BRENT SANDERSON: The reason why we're showing an increase to the distribution rate in our '06/'07 forecast as a result of UFG costs, while at the same time our forecast unaccounted-for percentage remains the same at 0.9 percent, is, as I suspected initially, in that our '06/'07 forecast our average unit cost of commodity is higher than was the case in the '05/'06 forecast or the amount that was embedded in the pre-August 1, 2006 base rates.

So, when we flow unaccounted for gas costs from the primary and supplemental PGVA's to the distribution PGVA, their costed at the prevailing market price of our acquired supplies. And so the fact that the forecast costs -- unit costs are forecast to be higher, our distribution rate as it relates to unaccounted for gas, would have to increase.

MR. BOB PETERS: Thank you. And I suppose when the percentage stays the same, really one (1) of the only variables then can be the commodity cost and that's what's driven that increase?

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

MR. BOB PETERS: Ms. Derksen, you were playing perhaps Santa Claus to the special contract customer class by providing them with a little refund; why haven't you lump sum refunded the other customer classes, in terms of the non-primary class PGVA balances?

MS. KELLY DERKSEN: Lump sum refunds are absolutely a consideration and we -- we did give thought to that type of process. There's a number of down -- drawbacks to lump sum refunds in my mind and we haven't aggressively pursued that type of mechanism in the past that I recall. I can recall in one (1) case maybe fifteen (15) years ago that we have -- we have done that. And some of the drawbacks include -- well of course there's some benefits.

And the benefits of a lump sum refund is that you minimize inter-generational issue. And inter-generational issues mean that those who have caused the cost or in this case, those who have caused the refund are better -- are those customers who are entitled to the refund or pay for the cost and not other customers who are in the system at the time.

Some of the drawbacks include the fact that its administratively very complicated to do. We have two hundred and fifty thousand (250,000) customers on our system and a lump sum refund basically suggests that we need to go and calculate some way, each of the refunds entitled to each of the two hundred and fifty thousand (250,000) customers we have on the system.

And so from that perspective, it's very time consuming. It's administratively complex. I think customers will be confused by that from a perspective that one (1) customer's refund will likely be different than his neighbour, and so that would cause concern for obviously some customers.

So from a number of perspectives, we don't consider -- we haven't considered a refund at this time in the form of a lump sum.

MR. BOB PETERS: Have you ever thought when the PGVA balances are owing to the Utility to invoice one (1) lump sum to each customer who owes you money?

MS. KELLY DERKSEN: The last time, Mr. Peters, that we talked about that was as part of the 1998 General Rate Application, so it happens very few and far between.

And of course, the drawback there is that it could be -- it could well be onerous for low income customers and so forth. And so we don't consider lump sum payments as a matter of course, in most cases, Mr. Peters.

MR. BOB PETERS: Thank you Ms. Derksen. Staying with Tab 14 of the book of documents and turning to Schedule 7.1.0 there's page 1 of 2 and 2 of 2 provided.

If we can start with page 2 of 2, the last page in the book of documents, Tab 14, Schedule 7.1.0, you're depicting what has been the impact on annual bills as a result of the interim application you made to the Board, am I correct?

MS. KELLY DERKSEN: From a base rate perspective, yes, sir.

MR. BOB PETERS: And in terms of a base rate perspective, what has happened in this schedule with respect to the primary gas bill impacts?

(BRIEF PAUSE)

MS. KELLY DERKSEN: Subject to check, Mr. Peters, I believe the August 1st primary gas base rates have been reflected in -- in this determination.

MR. BOB PETERS: All right. Does that then suggest that the -- what is depicted here is strictly the non-primary rate decrease, leaving aside the primary gas impacts from August 1st?

(BRIEF PAUSE)

MS. KELLY DERKSEN: Yes, Mr. Peters, we've kept the primary gas constant in both sides of the equation so as to highlight or extract just the impact of the non- primary gas impact.

MR. BOB PETERS: And so this non primary gas impact, that would be the reduction by $6.6 million from the previous year's rates?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: When we flip back to the billed rates on Schedule 7.1.0, page 1 of 2, there's a total of a 7 percent reduction and if I understood the direct evidence earlier that incorporates a reduction in primary gas rates which is about 4.2 percent or fifty-seven dollars ($57) a year and the balance would then be attributable to the non- primary gas rate reductions.

Have I that correct?

MS. KELLY DERKSEN: Mr. Peters, you do

have that correct. This Schedule 7.1.0 page 1 of 2, indeed, reflects both the impact of the change in the primary gas for August 1st, as well as the impact of the changes resulting out of the 2006/'07 non-primary gas costs.

And I'm going to have to confirm with you on the base rate calculation because I expect -- I'm -- I'm thinking at this moment that what I told you is incorrect, which means I'm thinking that primary gas was not kept constant on both sides of the equation for the base rate calculations.

MR. BOB PETERS: Thank you and I appreciate your just confirming that to the Board.

--- UNDERTAKING NO. 3: Ms. Derksen to confirm base rate calculation re Schedule 7.1.0 page 1 of 2.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Ms. Derksen, I suppose the Board's going to have to consider what happens a year from now and a year from now the impact of the reductions that the -- that the -- now, let me rephrase the question.

The -- the rate riders are contributing to lower gas rates than would be the case without those PGVA balances, correct?

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

MR. BOB PETERS: When -- when those balances of those PGVA accounts are entirely refunded or twelve (12) months' lapses, those rate riders are supposed to come off, correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: When those rate riders come off, even though the base rate hasn't changed, the consumers will see a rate increase on their bill -- a -- a bill increase in any event because the rate riders aren't there to dampen the impact?

MS. KELLY DERKSEN: Yes, both -- they will see both an increase in their rates on a general basis.

On an individual rate basis it might not work exactly out that way but on a general basis they will see increases in their rates as well as increases on their bills and that's one (1) of the downsides of having a negative rider or an amount owing to customers is that -- at that -- at some point that's going to be taken away and at that point then, all else equal, rates will increase.

MR. BOB PETERS: When you say, "rates will increase," what you're saying is the billed rate will no longer apply and you'll revert back to a base rate which could be higher than the billed rate and it has then the -- the consumer sees what amounts to an increase?

MS. KELLY DERKSEN: That's correct.

(BRIEF PAUSE)

MR. BOB PETERS: Ms. Derksen, I'm just looking at the confirmation of interim orders that have been requested by the Corporation and there is one (1) that stems back to November 1st of -- of '04, and that's a matter that was discussed at the last cost of gas or GRA matter but it just, through presumably oversight, wasn't specifically confirmed as final.

Would that be fair?

MS. KELLY DERKSEN: That's fair.

MR. BOB PETERS: All right.

In terms of the rural expansion orders, those are to expand the franchise area in which Centra can serve customers; would that be correct?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And in terms of the process, the rural municipality if to grant Centra a franchise or extension to their franchise area to allow

Centra to be able to serve additional customers.

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And in the normal process the municipality would give first reading to a bylaw that would give effect to granting Centra the franchise and asking Centra to make an application to the Board seeking approval.

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And once -- once that is given first reading then it is incumbent on Centra then to make the application to the Board, and these applications were made to the Board on a interim ex parte basis?

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

MR. BOB PETERS: And once the Board adjudicates on it, if the Board does grant the order approving it, that order is granted on an interim basis because it hasn't -- hasn't been the subject of a public hearing?

MS. KELLY DERKSEN: That's probably fair, Mr. Peters, yes.

MR. BOB PETERS: And then after the Board issues its order the municipality will proceed and give final reading to the bylaw and take such steps to allow Centra to expand their franchise area.

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: In the case of Order 132/'05, which was for the RM of Rockwood, I believe there were four (4) customers that were initially part of the expansion.

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And then along came a fifth.

MS. KELLY DERKSEN: I think there were more than five (5) but, yes.

MR. BOB PETERS: Well, when -- the initial application was premised that there would be four (4) customers and that was the feasibility test to -- to add those four (4) customers.

MS. KELLY DERKSEN: Yes. The feasibility test contemplated those four (4) customers at the time.

MR. BOB PETERS: And those four (4) customers are responsible to pay cost to make this project financially feasible according to the feasibility test that this Board has approved and that Centra uses.

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

MR. BOB PETERS: And what that often means is customers have to make contributions to the capital expenditures to get the -- the pipe to their -- to their premises.

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And when they do that, Ms. Derksen, and along comes an extra -- let's say a fifth customer, that fifth customer is getting the benefit of the infrastructure that has been paid for by the first four (4).

Would that be the case?

(BRIEF PAUSE)

MS. KELLY DERKSEN: Mr. Peters, in this case, because it's an expansion project, that fifth customer is also subject to the feasibilities that are run typically and that this customer, indeed, also paid a contribution.

A true-up will be done by Year 5 -- or at Year 5 which will contemplate the addition of this customer and the contributions that they paid. And to the extent that customers have overpaid in terms of contribution initially, we will be refunding that money to them at that time.

MR. BOB PETERS: Do you recall, Ms. Derksen, for this particular example, whether the one (1) extra customer that came along and had a feasibility test conducted on their premiss -- premises, whether that gave rise to incremental costs that were not covered by the first feasibility test or were they paying part of the costs that were identified in the first feasibility test for the initial four (4) customers?

MS. KELLY DERKSEN: I'm not sure that I could answer that at this point, Mr. Peters.

--- UNDERTAKING NO. 4: For Ms. Derksen to advise in the case of Order 132/'05, re RM of Rockwood, there were four (4) customers that were initially part of the expansion. The one extra customer that came along had a feasibility test conducted on their premises. To advise whether that gave rise to incremental costs that were not covered by the first feasibility test or were they paying part of the costs that were identified in the first feasibility test for the initial four (4) customers.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: All right. Recognizing that you may have five (5) customers then on the system and they've all made contributions of some level or another, why do you have to wait five (5) years to true them up?

MS. KELLY DERKSEN: Our financial feasibility test contemplates a five (5) year true-up, such that the revenue to cost ratio needs to equate to one (1) by that year. And so we typically wait to see if there's any other customers who materialize on that system and generally that's -- you know that's been our past practice.

MR. BOB PETERS: And so if additional customers join up onto the system when its trued up there may be refunds to the initial four (4) or five (5) who paid their capital costs earlier?

MS. KELLY DERKSEN: Possibly to all.

MR. BOB PETERS: When you do the true-up would each of the additional customers be responsible for the same share of the feasibility test?

MS. KELLY DERKSEN: Could you ask me that again, Mr. Peters, sorry?

MR. BOB PETERS: If the feasibility test identifies a certain dollar amount that is necessary to make the total project feasible, is that then divided equally amongst those who have hooked on for gas, or are they charged depending on their individual costs and volumes on the system?

(BRIEF PAUSE)

MS. KELLY DERKSEN: It would be based on individual circumstances, Mr. Peters.

MR. BOB PETERS: In the expansion in the St. Anne's municipality, there was one (1) customer and I think the additional cost was five hundred dollars ($500) and there have been no additional customers identified for that expansion?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And in terms of north Cypress, Order 28/'06, this is where Centra took over the operation of a gas co-op?

MS. KELLY DERKSEN: Yes, sir.

MR. BOB PETERS: And there's one (1) customer on this, is this -- have I got this right?

MS. KELLY DERKSEN: No, sir, there's several customers including a Hutterite colony.

MR. BOB PETERS: And is this now then treated as the co-op class in the rate category?

MS. KELLY DERKSEN: No, they've been spread among the rate classes that are existing and the co-op class is not one (1) of them.

MR. BOB PETERS: When Centra expanded to take over the co-op were there capital costs that were incurred?

MS. KELLY DERKSEN: I don't believe there were, Mr. Peters.

MR. BOB PETERS: Did Centra run a feasibility test on the co-op, using the assumptions that it determined would be applicable?

MS. KELLY DERKSEN: I think yes, that's true.

MR. BOB PETERS: And there was no contribution then required from the co-op customers for Centra to take it over?

MS. KELLY DERKSEN: No, sir.

MR. BOB PETERS: Is this one (1) subject to a true-up, as well?

MS. KELLY DERKSEN: No, sir.

MR. BOB PETERS: The last one was another expansion to Rockwood Municipality in Order 102/06 and I believe there were eight (8) customer additions and contributions received, is that right?

MS. KELLY DERKSEN: Yes.

MR. BOB PETERS: And again that will be the subject of a five (5) year true-up?

MS. KELLY DERKSEN: Yes, it is.

MR. BOB PETERS: And since that Order, have there been any additional customers identified?

(BRIEF PAUSE)

MS. KELLY DERKSEN: No, there haven't.

MR. BOB PETERS: Sorry, and that one's also subject to a five (5) year true-up?

MS. KELLY DERKSEN: Yes, it is.

(BRIEF PAUSE)

MR. BOB PETERS: If I can turn -- I believe, Mr. Stephens, this may come back to you. In terms of Board directives at Tab 8 of the application there was a -- a number of documents filed and some information provided and one (1) of the issues that was to be looked at by the Corporation was natural gas storage. Do you recall that?

MR. HOWARD STEPHENS: I do, sir.

MR. BOB PETERS: And in terms of natural gas storage that's not a new issue before the Board because the Board back in I believe 2003 had an opportunity to consider what I think had been called a blank page analysis or a -- a consultant's report as to what Centra should do with its assets that underlie its gas supply.

MR. HOWARD STEPHENS: Yes, on the basis of what -- how we should reconfigure our assets post-day in our arrangements.

MR. BOB PETERS: What you're saying is that the Board wanted the Company to examine whether or not it should change its asset mix, and its assets being the transportation and storage arrangements, to perhaps some other portfolio that would be more cost effective for consumers?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And the upshot of that report from your consultant was what, Mr. Stephens?

MR. HOWARD STEPHENS: They -- generally speaking they just rejigged some of our assets. They reduced the amount of TransCanada capacity. They had us bringing a little bit more gas coming up from the States and developing storage in Saskatchewan or potentially in western Manitoba. That's a very high level overview.

MR. BOB PETERS: All right. And -- and the high level overview of why storage was even needed for Manitoba was what?

MR. HOWARD STEPHENS: One was to provide a peaking service and many of the other attributes associated with storage, those being the natural hedging effects associated with storage, but primarily it was to increase the load -- our purchase load factor and to provide the additional peaking service that we currently undertake using the capacity management arrangements.

MR. BOB PETERS: Now, when you say, "improve the purchase load factor," can you explain what you mean by that to the Board?

MR. HOWARD STEPHENS: Sure. We have a sales load factor into our -- into our system which is for the residential class of customers, 32 percent. Our purchase load factor under our existing set of assets on the TransCanada Pipelines with design load factor in a normal year is about 78 percent notwithstanding all of our capacity management transactions that bring it much higher.

And what additional storage would allow us to do is reduce the amount of pipeline capacity we have and use storage as a buffer on peak day -- peak days or very cold days and allow us to run our gas commodity at a much higher purchase load factor.

MR. BOB PETERS: And if you didn't

improve your purchase load factor, you'd be subject to some penalties or demand charges that would add to the cost of gas?

MR. HOWARD STEPHENS: Well, it remains to be seen as to just exactly how high they will be, but there is typically, I mean, oh, and we've discussed this this morning or this afternoon, the swing service that we have under our current Nexen contract essentially provides some of the service that storage was providing, and it comes at a premium.

So to the extent that you need flexibility within your gas supply arrangements, you will pay some optional costs over and above the index.

MR. BOB PETERS: When Centra was looking to improve its purchase load factor by finding storage, did Centra initially consider storage in Michigan as well as salt caverns in Saskatchewan?

MR. HOWARD STEPHENS: Actually, I mean, the arrangement that we currently have were the second choice of an assessment that we did back in 1989. And the initial recommendation of the consultant at that time was that we acquire TransGas storage at that time, but TransGas could not at that point develop enough storage for us to meet the deadline that was driving the whole arrangement.

MR. BOB PETERS: And so Michigan was chosen because of the time it was going to take to develop the Saskatchewan storage sites.

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And the Michigan storage was developed at a significant cost. Was that paid by the utility or by the -- by ANR?

MR. HOWARD STEPHENS: Well, the storage already existed. We were just buying a storage service and signing a contract with the commitment to pay a certain amount of dollars every year. So from that perspective ANR purchased -- or made the investment and we're paying the freight associated with it.

MR. BOB PETERS: And that freight that you're paying is the, as we've referenced, is the $14.7 million US.

MR. HOWARD STEPHENS: That's right.

MR. BOB PETERS: You call it a revenue cap, I guess it's their revenue.

MR. HOWARD STEPHENS: That's right. I mean, they've designed the rates so that they collect the revenue cap or something very close to it almost every year.

MR. BOB PETERS: And as a result of that storage, what has happened to purchase load factor in

Manitoba?

MR. HOWARD STEPHENS: Well, as I mentioned just a few minutes ago, our design in terms of on the TransCanada pipelines is seventy-eight (78) to 80 percent as opposed to -- as opposed to prior to having storage we ran on a pipeline about 50 percent load factor, which meant that we were paying essentially double the rates for the capacity that we had contracted.

MR. BOB PETERS: And all the while that that storage wasn't developed, it was saving Manitoba consumers money.

MR. HOWARD STEPHENS: You seem to have some question with respect to that last part. Yes. That's the -- that is the short answer.

MR. BOB PETERS: And the Michigan storage arrangement, I think you've heard -- I've heard you say that it -- it expires in 2013?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And as part of that blank page analysis back in 2003 Centra was looking at whether it should sell or assign that if it legally could or what to do to find perhaps cheaper ways to provide gas to Manitoba, and that was the upshot of that report.

MR. HOWARD STEPHENS: Well, really, I mean, the -- the initiative for doing the blank page analysis is that I was being challenged in a number of circumstances at proceedings like this in terms of the veracity of that arrangement. So I committed one year to say, Okay, we'll have a look at this to see what we can do given the current marketplace and conditions and come up with, I mean, what would be ultimately the appropriate answer.

The difficulty associated with that was that the environment was changing almost minute by minute, so that it was very hard to make the necessary assumptions that you need to make when you're developing a portfolio of assets to serve a certain market.

Our market was changing, the market around us was changing, so a variety of different factors made it very difficult to come to any solid conclusions.

And in any event, the consultant's recommendation indicated that there was no urgency for us to try and extricate ourselves from our existing arrangements, that we could let those contracts play themselves out because there is the revenue cap associated with the ANR arrangement, that is becoming more valuable every year or a lower cost every year if you take into consideration the effects of the cost of money.

And TransCanada capacity, there is

certainly more than enough there. And we've been able to satisfy our peak day requirements without having to add a significant expenditure in terms of the development of storage.

MR. BOB PETERS: Can you explain to the Board briefly why TransCanada pipeline capacity has -- is so prevalent and available?

MR. HOWARD STEPHENS: Well, after the significant change in the marketplace in 2000/2001, the development of the Alliance pipeline, there is -- TransCanada basically got themselves into a position where they were no longer competitive.

And the Alliance pipeline took a considerable amount of the volume that's been -- the newly produced volume in Alberta and was moving it down a bullet pipeline, into the Chicago market.

And that is -- that has eroded TransCanada's presence in the marketplace.

MR. BOB PETERS: And there still is, ample, in your view, capacity on TransCanada pipeline if for some reason Manitoba needed more?

MR. HOWARD STEPHENS: The last numbers that I've read vary from -- this is post-Keystone, assuming they proceed with the Keystone project which is converting a portion of the pipeline to oil.

Minimally, we'll see over the course of the next fifteen (15) years is at least 1.2 BCF per day of excess capacity and going up as high as 2.25.

I mean -- and that's enough capacity to serve us for a good long time.

MR. BOB PETERS: And as a result of that, you haven't been pursuing any other storage arrangements, would that be fair?

MR. HOWARD STEPHENS: No, I alluded to the fact that we will be reviewing this again because I'm not necessarily convinced that we have the perfect set of assets. And certainly if we have a declining use per customer, and our requirements to satisfy customers is starting to reduce, then we have to know which is the best component to divest ourselves of.

And so that certainly is very much on the top of our mind.

MR. BOB PETERS: Can you tell this Board whether the Saskatchewan storage fields have been developed?

MR. HOWARD STEPHENS: Actually we met with Trans Gas -- was it a month ago -- about a month ago and we had some discussions with them, very high level discussions with them. We had had some initial discussions when the original portfolio review was done, but they were very specific to developing a very specific storage site.

Trans Gas right now, is very much in the marketing mode. They have many opportunities in terms of developing storage. They really don't have a need for it themselves, so they're out trying to drum up business and this is a very good time, in terms of the marketplace and the dynamics of the marketplace, for them to be selling storage.

So they're looking for -- and I mean and they came to visit us and, basically, I tried to -- I mean identify what our requirements would be, in terms of providing a storage type service very similar to what we have from ANR right now where we don't have to make an investment. They would make the investment and we would have to commit for some timeframe and some sort of rate associated with it.

MR. BOB PETERS: So it's not -- they haven't decided to build it and they will come, they're waiting for somebody to indicate they want it and help figure out how to pay for it?

MR. HOWARD STEPHENS: That's right.

MR. BOB PETERS: And so for Manitoba Centra's operations haven't expressed any interest in pursuing Saskatchewan storage?

MR. HOWARD STEPHENS: We haven't given them a definitive answer. We've said we're looking at it and if and when it does make sense to us, then we would proceed.

MR. BOB PETERS: So an open-ended indication that sometime in the future and that future would be between now and 2013, presumably if you were going to act on it, because your arrangement expires with ANR at that time.

MR. HOWARD STEPHENS: Well, it would have to be sometime prior to the 2013, it takes time for them to develop the storage, unless they could manage our load with their existing assets.

MR. BOB PETERS: All right. I appreciate it takes lead times to build a storage -- storage facilities, what approximate lead time do you think it takes?

MR. HOWARD STEPHENS: I'd have to talk to Trans Gas because I mean we're talking an entirely different -- I mean, under the scenario that we were talking before, it was building specific facilities and that was going to take up to about four (4) years to get them all into place and serviceable.

Depending upon how much excess storage they have on their system right now, they may be able to take a portion of us almost immediately and then develop the storage over the period of a number of two (2) or three (3) years.

MR. BOB PETERS: Is Trans Gas also a potential recipient of request for proposal to supply gas on a long term basis?

MR. HOWARD STEPHENS: They don't have a significant component or amount of production. So we won't be looking at them very hard in terms of providing us with a commodity immediately.

Perhaps on the longer term once we've established what our portfolio of assets looks like, we may include them in that portion of it.

MR. BOB PETERS: In addition to the storage facilities, the Board also wanted you to look at the future gas supply contracts and their -- and to that end I believe you indicated you hired EEA, which stands for Energy Environment Assessment?

MR. HOWARD STEPHENS: I'll take your word for it.

MR. BOB PETERS: No, I'm stretching --

MR. HOWARD STEPHENS: "Analysis" is the last word.

MR. BOB PETERS: All right. All right, sorry. Energy and environment analysis?

MR. HOWARD STEPHENS: That's right.

MR. BOB PETERS: And they're doing a report for you?

MR. HOWARD STEPHENS: Yes.

MR. BOB PETERS: And does that report look at the storage component or just the gas supply contract component?

MR. HOWARD STEPHENS: It contemplates some of the potentials -- potential benefits associated with storage but that would be a phase 2 component of it. Their direct mandate right now is to identify for us the most cost effective way to replace or -- and/or renew our Nexen contract given our existing set of assets, simply from the perspective that I can't get out from under them unless I really want to spend a lot of money trying to buy my way out of the ANR contract.

MR. BOB PETERS: But it would be fair to say you haven't investigated that with any diligence in terms of who would be out there to buy your -- to buy your obligation that's capped at 4.7 million?

MR. HOWARD STEPHENS: I --

MR. BOB PETERS: Or 14.7 million?

MR. HOWARD STEPHENS: Sorry, Mr. --

MR. BOB PETERS: Well, I'm just --

MR. HOWARD STEPHENS: Just -- could you

run it by me again? I was just thinking about Mr. Stewart.

MS. LORI STEWART: We're wondering whether I'll be referred to as Ms. Stephens.

MR. BOB PETERS: It's entirely possible. I -- but just let me pick up that thought about the EEA assignment. They will be looking at whether or not you should renew or replace the Nexen long-term gas supply contract and in making the recommendations they may look at certain aspects of storage or related ways to -- to accomplish the gas supply that Nexen's presently doing.

MR. HOWARD STEPHENS: There's no question and that's -- that's precisely what they're doing and I mean in terms of determining the appropriate supply basin and looking at the variety of factors associated with diversity of supply we all know that the WCSB is in decline so should we be continuing to contract there? Should we be contracting with the sole supplier in terms of a marketer or divest -- diversifying the -- the portfolio?

All of those things tend to drive out -- okay, you should be buying your gas, say, some portion of it from western -- the western Canadian sedimentary basin, some of it from perhaps the States, Chicago, et cetera, and so when it comes time to reconfigure your portfolio, you now know where you're going to buy your gas from because you know what makes the most sense from a pricing perspective. And then you put the assets in place to satisfy that.

Now, it's a somewhat iterative process and certainly interlinked but that is the first step of the process.

MR. BOB PETERS: We'll watch to see whether you're dining with any of the Intervenors this week as to whether you have some more exploratory talks on that, Mr. Stephens, but suffice it to say then you're not asking for anything related to additional storage or storage arrangements or the assets you have right now for storage; you're content with what they are?

MR. HOWARD STEPHENS: Right now -- right now we're serving the market as cost effectively as we can.

MR. BOB PETERS: And in terms of EEA's review and study to analyse the options for either renewing or replacing the Nexen agreement, Centra Exhibit 5, which I introduced with the belated permission of your counsel this morning is also found in Tab 15 miraculously.

It's a document that Centra has sent to the Board indicating that it needs a bit more time and I believe either you or Mr. Warden indicated that in your direct evidence this morning.

MR. HOWARD STEPHENS: Yes, I think -- I think we both alluded to it, yes.

MR. BOB PETERS: Can you -- and -- and maybe this might be even a -- might be more fair for your counsel to consider as a part of her closing submission, but what process does Centra envision being taken once -- once it gets the information from EEA and does its internal reviews and makes a filing with this Board? Is there some thought?

Is there a -- are you asking for a -- a review process or do you know at this point in time?

(BRIEF PAUSE)

MR. HOWARD STEPHENS: I mean, really, our two (2) choices are to go into an RFP or to renew with Nexen. The Board has indicated that prior to us releasing an RFP they want to see the -- the document. We would certainly file it in advance, as -- as appropriate. And prior to signing off on the contract, I mean, we would also bring the contract before the Board and seek their approval with respect to moving down that path.

Now, in what context, during what hearing would we do that, I -- I don't know.

MR. BOB PETERS: We'll leave that then for a matter of future discussion.

I'm being urged to perhaps indicate this would be an appropriate place to take a -- the recess for the day. And just to ensure people come back tomorrow, we'll talk about potential changes to WTS service, broker costs, but we will spend most of our time talking about hedging for -- and I expect to be finished by lunchtime tomorrow.

THE CHAIRPERSON: Very good. We'll see you all tomorrow at 9:00. Thank you.

--- Upon adjourning at 4:00 p.m.

Certified Correct,

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Wendy Warnock, Ms.