MANITOBA PUBLIC UTILITIES BOARD

Re: CENTRA GAS
COST OF GAS APPLICATION

Before Board Panel:

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

HELD AT:

Public Utilities Board
400, 330 Portage Avenue
Winnipeg, Manitoba
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Volume I
Pages 1 to 219

APPEARANCES

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

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LIST OF UNDERTAKINGS

--- Upon commencing at 9:03 a.m.

THE CHAIRPERSON: Good morning, ladies and gentlemen. I want to call this public hearing to order. I am Graham Lane, Chairman of the Public Utilities Board and I am joined by two (2) other Board members; to my right, Ms. Monica Girouard and to my left, Mr. Mario Santos.

Also with us today is Mr. Hollis Singh, Associate Secretary to the PUB and Bob Peters, Board Counsel. In due course, Mr. Peters will introduce the other members of the Board Advisory team.

Centra Gas applied to the Public Utilities Board for approval as of November 1st, 2004 for a rates for supplementary gas, transportation to Centra, and distribution to customers.

For this hearing, Centra updated its initial application for the PGVA and gas cost deferral account balances and published a notice indicating forecast rates related to its Application.

As part of its Application, Centra also requested final approval of 2003/04 gas costs, non-primary PGVA and other gas cost deferral account balances; final approval of interim orders since the 2003/04 General Rate Application; approval to refine the allocation of unaccounted for gas; approval to amend the billing of demand related to costs for high volume customers, approval to make miscellaneous adjustments to the terms and conditions of service, and approval to remove the income tax component from Centra's feasibility test.

Centra has provided its response to Board directives from Order 118/03, these relating to cost of gas matters including its gas supply portfolio and derivative hedging policy.

Recently, Centra provided updates of its contractual arrangements.

Along with these matters, Centra and Intervenors provided the Board with preliminary views with respect to matters raised by the Board at the April pre-hearing conference, those being: the question of the competitive landscape; the roles and rights of the parties within it and the implications for the public interest, and the appropriateness of regulation based on rate base and allowable rate of return.

We will touch upon those landscape and regulatory oversight matters during the course of the Hearing but do not anticipate resolving all of them.

Parties can provide their further advice in these areas to the Board in closing submissions.

Mr. Peters will cover the matters related to this Hearing in more detail during his upcoming statement.

Centra Gas Manitoba Ltd. is a wholly-owned subsidiary of Manitoba Hydro, Manitoba's largest Crown Corporation. Hydro conducts operations in the energy related fields of electricity and natural gas and is also involved in activities with respect to alternate forms of energy generation and demand-side management; demand-side management being matters related to efficiency and conservation.

Unlike electricity which is generated within Manitoba, natural gas is imported into the province with the benefits from its production and sale falling to other producer provinces.

Natural gas and electricity have inter-related economic concerns with respect to efficiency and conservation, particularly now that natural gas pricing pressure has pushed the average cost of space heating past that of electricity.

Lower consumption of natural gas reduces the impact of higher commodity prices and this may provide continued support for the selection of natural gas over electricity for space heating and other energy needs.

Measures undertaken to reduce gas consumption may provide improved opportunities to export electricity, supporting Manitoba's electricity rates. Thus, efforts to achieve natural gas consumption savings can be supported by economic as well as public policy reasons.

Reliable, efficient, and cost-effective natural gas service is of critical importance to the two hundred and fifty thousand (250,000) homes, businesses, and organizations that rely on it. Energy costs affect transactions ranging from property purchases to industry operations and expansions.

Centra's commodity costs are passed through to the customer without mark up. Despite the pass-through nature of commodity costs, the Board is unaware of any current plans for major expansion of the service, the prospects for expansion being reduced by the high end rising cost of the commodity.

Centra's operations are integrated within those of its parent, Manitoba Hydro. The overall Corporation is administered by a government-appointed Board, led by an experienced President.

The utility's decisions and operations are subject to a number of oversight bodies and processes including those of the government, the legislature, Crown Corporation's Counsel, Clean Environment Commission and this body, yet the fact that the oversight is shared, does not imply the responsibilities of this Board are reduced or unimportant.

Before calling on Mr. Peters, I want to make a few general comments related to these proceedings. The purpose of these proceedings is to inform this panel sufficiently to allow it to reach a conclusion on Centra's Application.

The Corporation has produced voluminous and significant information related to and in support of its Application. It goes without saying that without the co-operation of the Corporation, which is charged along with the Intervenors with the responsibility of assisting the panel in reaching a proper decision, it would be next to impossible to reach proper conclusions.

The Corporation will present and support its case and Application. The evidence to be provided will be tested by Board Counsel and the Intervenors through cross-examination.

Intervenors are very important to the process. Through the Intervenors, the understanding of the Public Utilities Board of the interests and concerns of the utilities rate payers are more fully identified.

Following cross-examination, the process will move on to final argument and following -- following closing argument, the panel, myself and my two (2) colleagues, will sequester ourselves and deliberate to reach a final determination on the matters before us.

In the end, we may accept, deny, or vary the company's Application. In brief, we could determine that the rate schedules proposed by Centra should be varied to achieve objectives arising out of this Hearing. As well, we could amend the regulatory framework to govern future rate hearings. As previously indicated, your submissions are welcome and important.

Whatever decisions we make, will be made carefully with the implications and consequences understood as best as possible. In reaching our decision, we will be guided by the evidence, written and oral, and our determination of what represents the public interest.

It goes without saying that our expectations of all those who appear before us include effective participation, comprehensive presentations and examinations, all toward the objective of assisting the panel in making proper decisions and a cooperative approach by all.

Shortly I will call on Board Counsel, Mr. Peters, to make further introductions and to further outline the purpose of the hearing.

We have allocated to Mr. Peters the responsibility of guiding us through this proceeding. The current expectation is that the Hearing will occur over the last three (3) days of this week and next week, with September 22nd set aside for final argument.

Our normal schedule have us beginning at nine o’clock each day, breaking for lunch at noon and resuming at

2:00. We will adjourn each day at 4:00.

If it becomes apparent that we will be unable to complete our work in the days set aside, we will consult with those involved and if additional days are required, provide as much notice as possible.

Now, Mr. Peters...?

MR. BOB PETERS: Good morning. Thank you, Mr. Chairman, Board Member Girouard, Board Member Santos, ladies and gentleman. For the record, my name is Bob Peters and I act as Counsel to the Public Utilities Board of Manitoba.

I am assisted by the Board's accounting advisors from Price Waterhouse Coopers and, in particular, Mr. Brent McLean and Mr. Roger Cathcart, and Roger is with me on my left.

We are also assisted by the Board's engineering advisors from Energy Consultants International, particularly Mr. Myron Kostelnyk, Mr. Jim Sandison behind -- seated behind Mr. Kostelnyk.

Centra presently has five (5) major components in its gas base rates and those are the primary gas rates, the supplemental gas rates, the transportation to Centra rates and the distribution to customer rates, as well as a basic monthly charge.

The primary gas component of Centra's rates is the subject of quarterly primary rate adjustments and are not -- and is not part of this Hearing. The last primary rate adjustment was on August 1st, 2004, and this Board will be aware that the next primary rate adjustment is scheduled for November the 1st, 2004.

The primary gas component of Centra's rates recovers the cost of supply which is received from Western Canada sources and represents the vast majority of Centra's overall supply of gas.

The non-primary gas costs, which we're going to focus on in this Hearing, include supplemental gas, transportation, and distribution. The supplemental gas rates recover the cost of gas purchased primarily from US sources and those are over and above the primary gas supplies.

The transportation to Centra component of rates recovers the costs associated with transporting all gas supplies to Manitoba, including storage gas. The distribution to customers component of rates recovers the costs associated with Centra operating utility and the cost related to unaccounted for gas.

The Board last reviewed the distribution component of rates in the Public Hearing process that led to Order 118/03 in 2003.

Total gas cost forecast for 2004/05 fiscal year of the Corporation has been updated based on a forward price strip as of July 2nd, 2004, and based on my reading of the materials, is $420.5 million of which the non-primary gas costs total approximately $83.4 million.

In this Application, Centra has requested approval of supplemental gas rates, transportation to Centra rates, and distribution to customers' rates, to be charged by the utility for the sale of gas and the provision of transportation and distribution services to their customers, to be effective with respect to all gas consumed on and after November 1 of 2004.

I should stress, Mr. Chairman, and Board Members, the only component of Centra's distribution rates that are going to be addressed in this Application, is the portion related to unaccounted for gas.

In addition to -- to those rates, Centra is seeking a lengthy list of approvals which I will put on the record of this transcript, and those approvals include: final approval of April 1st, 2003 to March 31st, 2004 gas costs, final approval of the various non-primary purchase gas variance account, and gas cost deferral account balances, as at March 31st, 2004, with carrying costs calculated forward to October 31 of 2004.

They also seek approval of the disposition of these non-primary purchase gas variance accounts and gas cost deferral account balances over a nine (9) month period, ending July 31st of 2005.

Centra is also seeking final approval of supplemental gas, transportation to Centra, and distribution to customer sales rates that were effective from August 1st, 2003, and approved at that time on an interim order in Board Order 125/03.

Final approval of Interim Order, Ex-parte Orders 119/03, 161/03, 11/04, and 100/04, related to the approval of the interim primary gas sales rates is also being sought, and in the case of Order 100/04, the removal of supplemental gas, transportation, and distribution rate riders as of July 31st, 2004.

Centra is seeking final approval of Interim Ex-parte Order 143/03 and 69/04, in which the PUB approved amendments to the primary gas rate setting process and minimum filing requirements.

Additionally, approval is sought on a final basis of the Interim Ex-Parte Orders 120/03 and 121/03, which are related to the approval of amended franchise agreements and feasibility tests for the extension of gas service to certain customers in the rural municipality of Rockwood and the rural municipality of Hameota (phonetic).

Centra is seeking final approval of Interim Ex-Parte Order 44/04, related to the approval of the inclusion of an additional zone in its atmospheric pressure zones, as set forth in the Terms and Conditions of Service.

There is also approval being sought to change the allocation of unaccounted for gas to the various customer classes as part of the process in calculating sales rates, and I will have more to say on that when we go through the outline of procedures.

Centra is also seeking approval to implement the billing and demand related costs for the high volume firm customer class, using actual demand from the November 1st, 2003 to March 31, 2004 period, and that billing would commence at the new rates on November 1st, 2004, should Centra's Application be approved.

And, narrowing down the list, Centra is also seeking approval to make miscellaneous adjustments to the terms and conditions of service to ensure consistency with their operations and previous decisions of this Board.

And, as you noted, Mr. Chairman, Centra is seeking approval to remove the income tax component from the feasibility test used to assess the financial feasibility of the proposed expansion to a new franchise area or main extension in a -- in an existing franchise area to be effective on January 1st, 2004.

As you commented in your comments, Mr. Chairman, and also was noted in the public notice dated March 17th, the Board has indicated that it will initiate a discussion on the form of future regulation of the utility and would request comments from Centra and the Intervenors in this Hearing on that matter.

Centra's original Application requested approval of new rates to be effective on August 1st of 2004. However, in recognition of the timing of this hearing, the rate implementation date was amended to November 1st, 2004 and public notice was given in the March 17th, 2004 notice.

This Application was revised on August the 9th, 2004 to reflect more current information, particularly updated gas costs.

In its original filing, Centra estimated a decrease of approximately 5.2 million dollars for non-primary gas costs for the 04/05 fiscal year over those included in the currently approved rates, and in addition to that decease, Centra was planning on refunding approximated 14.5 million dollars of the estimated balances of various non-primary PGVA and gas cost deferral accounts to March 31, 2004.

As a result of the update on August the 9th, which used the July 2nd, 2004 forward price strip, the reduction in non-primary gas costs for the 04/05 fiscal year was revised to 3.2 million dollars over those costs included in the currently approved base rates and also there was a revision for a refund of approximately 16.5 million dollars of non-primary gas PGVA accounts and gas cost deferral accounts based on actual balances at March 31, 2004.

The PGVA includes carrying costs and, I think, also rate rider amortization to October 31 of 2004, and is to be refunded through transportation to Centra and distribution to customer rate riders over a nine (9) month period ending July 31st of 2005.

If Centra’s Application is approved and -- as updated, there will be the following resultant range of estimated annual bill impacts relative to the August 1st, 2004 existing rates, and these bill impacts would depend on the volumes consumed.

For the SGS class, which includes the residential customers, there would be a decrease of 3.9 percent to 4.2 percent. For the LGS class, there would be a decrease of 2.8 percent to 3.4 percent.

For the mainline customer, there would be a decrease of 4.2 percent to 6.2 percent. For the high volume firm customers, there would be a decrease of 7.2 percent to 8.3 percent.

For the interruptible class, there would be increases of 1.2 percent to 1.4. For the co-op class there would be an increase of 5.8 percent to 5.9 percent. For the special contract class, there would be a decease of 19.3 percent and for power stations there would be an increase of

13.2 percent.

Let me summarize those by saying, for a typical residential consumer, there would be an annual decrease of approximate 3.9 percent, or fifty-two dollars ($52), if the Application before the Board is approved.

I should comment and remind the Board that these bill impacts do not take into account any impacts that may result from a change in the primary gas sales rate on November the 1st, 2004.

And, Mr. Chairman, with that overview of the Application, I'll turn it back to you and you may wish to canvass with the other parties any opening comments and introductions they have. Thank you.

THE CHAIRPERSON: Thank you, Mr. Peters. Now, we'll proceed to ask the Centra Gas and Intervenors to provide introductions to those in their parties and to make general opening remarks. So, I'll begin with Centra.

Ms. Murphy...?

MS. MARLA MURPHY: Good morning, Mr. Chairman, Members of the Board. I don't intend to make any formal opening comments this morning. Mr. Peters has reviewed the approvals which Centra is seeking in this Application but I will just take a moment to introduce myself and Centra's representatives that are here today.

For the record, my name is Marla Murphy, I act as counsel to Centra Gas. Appearing with me as co-Counsel and seated behind me is Brent Zarnicki (phonetic), also of the Manitoba Law Department. Unfortunately, Mr. Jim Foran, who appeared at the pre-hearing conference was unable to continue to act in this matter due to some personal health problems that he was having.

During the course of this hearing, Centra intends to have seven (7) witnesses appearing. First, addressing the cost of gas issues including gas cost forecasts, derivative hedging, the new gas supply contracts, the blank page analysis, is the Panel which is here this morning.

By way of introduction, to my immediate right is Mr. Vince Warden who's the Vice-President of Finance and Administration and Chief Financial Officer; Ms. Lori Stewart, who's the Manager of Gas Supply Pricing and Administration; Mr. Howard Stephens, Manager of Gas Supply, Transportation and Storage; Mr. Brent Sanderson, Senior Gas Cost and Hedging Analyst; and Mr. Rainkie, who's Manager of Rates and Regulatory Services.

And behind us in the back row, providing support for the Panel is Brent Zarnicki, who's in my immediate left; Christine Folks (phonetic), Regulatory Coordinator; Mr. Mack Kast is Division Manager of Gas Supply; Mr. Robin Wiens, Division Manager of Rates and Regulatory

Affairs; and Mr. Craig Kellis (phonetic) who's the Manager of Market Forecasting.

Once this Panel has presented their evidence and been cross-examined, we'll as the Board to excuse Mr. Stephens and Ms. Stewart and we'll bring to the panel Ms. Kelly Dirkson, who's a Senior Analyst of Gas Rates and Mr. Greg Barnlund, who's a Senior Consultant of Gas Rates and Policy and both Mr. Barnlund and Ms. Dirkson are present in the audience this morning.

That panel, which will include Mr. Warden, Mr. Sanderson and Mr. Rainkie as well, will address cost allocation and rate design issues as well as the high volume firm demand rates and will speak to Centra's terms and conditions of service. That panel will also appear at the appropriate time to discuss the UFG issues that were -- were before the Board.

Subject to any questions which the Board might have, that concludes my opening comments. I spoke with Mr. Singh this morning and I understand that both the Affidavit of Service and publication of the Notice of Hearing and Pre-Hearing Conference which was dated April 7th, 2004, and the Affidavit of Publication and service of the Reminder Notice which was dated August 31st of 2004, have been recorded with the Board Secretary as exhibits. Thank you.

THE CHAIRPERSON: Thank you, Ms. Murphy. Now we'll move on to the Intervenors. I'll ask each of them in turn to introduce themselves and if they want to make some brief remarks I will do it in alphabetical order.

To begin with, it would be the Canadian Association of Consumers and Manitoba Society of Seniors represented, I believe, today, by Mr. Kris Saxberg.

Mr. Saxberg...?

MR. KRIS SAXBERG: Not the best way to start but thank you, Mr. Chairman. Good morning Board Members and Ladies and Gentlemen. My name's Kris Saxberg and I am the lawyer for the Consumers' Association of Canada and the Manitoba Society of Seniors and my colleague, Brian Meronek will also be participating in this hearing; he'll be monitoring it as well as possibly providing some closing submissions.

The -- with us -- with me today is Gloria DeSorcy from the Consumers' Association of Canada, that's the second row and also from the Manitoba Society of Seniors we have Charles Groudin (phonetic) and Laurie Hunter (phonetic) and they'll be in and out monitoring these proceedings through the course of the next three (3) weeks.

In terms of our level of participation, we plan to actively participate in this hearing through cross-examination and then providing our comments during closing submissions and we will reflect very carefully on the transcript and the evidence presented in this hearing before formulating those positions and then communicating them to the Board. And subject to -- to any questions that you may have about our level of participation, those are my comments.

THE CHAIRPERSON: Thank you, Mr. Saxberg. Next on our list is MacDon Industries Ltd. and I see Mr. Carroll.

Mr. Carroll...?

MR. BILL CARROLL: Thank you, Mr. Chairman, my name is Bill Carroll, I'm President of Carroll and Associates Ltd.; I'm representing MacDon Industries Limited. Mr. Allan MacDonald, President and CEO of MacDon Industries will be here I believe on September 15, Wednesday and at that time he'll speak to the Brief that we have submitted, that the Board has in front of it.

MacDon's chief concern through these Hearings is the high volume firm change to the demand billing methodology, although MacDon does have some other broader concerns in terms of competitiveness and sustainability for industries in Manitoba that are gas users; and particularly users of gas as product input rather than space heating.

So we'll be speaking to those issues more fully on Wednesday next. Thank you.

THE CHAIRPERSON: Thank you, Mr. Carroll. For Municipal Gas and Direct Energy, Ms. Melnychuk is here.

Ms. Melnychuk...?

MS. KAREN MELNYCHUK: Good morning, Mr. Chair and Members of the Panel. Direct Energy Marketing Limited operates in Manitoba as Municipal Gas. Municipal Gas is a registered broker selling natural gas in Manitoba to both commercial and residential consumers.

Municipal Gas is -- intends to participate in this Hearing both through the cross-examination of some of Centra's witnesses and by submitting final argument.

I have the pleasure of addressing to you these opening comments. Our counsel Mr. David Brown of Stikeman's will be in attendance on our behalf later in this proceeding as required in light of the issues on which our intervention will focus.

Our intervention will focus on two (2) issues. One, the new primary gas supply contract.

First in this Hearing, Centra's seeking PUB approval of the cost consequences of the new primary gas supply contract it has entered into with Nexen Marketing. In Centa's 2003 distribution rates hearing held last year, Municipal Gas pointed out a number of the operational limitations constraining WTS offerings in Manitoba that resulted from terms and conditions as Centra's long term primary gas high contracts.

In Section 8.5.3 of its Board Order 118/03, the PUB noted the concern raised by Municipal Gas regarding Centra entering into a new gas supply contract. I quote:

> "Municipal urge the Board to require Centra to consult with ABM's prior to making any decisions on renegotiating its new gas supply and transportation arrangements with TCPL."

End quote.

The PUB also noted Municipal also recommended the Board advise Centra that if Centra failed to consult with interested parties in this matter, the Board would consider penalizing Centra by reducing its allowed return on equity in the next rate proceeding.

In Section 8.5.4 of its Decision, the PUB held:

> "The Board urges Centra to involve all stakeholders in the upcoming review of all aspects of Centra's gas supply including commodity storage and transportation arrangements."

Municipal Gas is very concerned that Centra did not follow the consultation path urged by the Board in its Order 118/03 and in this Hearing, Municipal wishes to explore why that happened and with what result.

Our second issue is the primary gas

advertising campaign. The second issue that Municipal Gas wishes to address involves the public relations campaign that Centra and Manitoba Hydro have embarked upon in recent weeks featuring annotes and information brochures entitled "It's Your Natural Gas, It's Your Choice".

Municipal Gas regards the campaign as an effort by Centra and Manitoba Hydro to dissuade consumers from entering into direct purchase contracts. This is a very serious matter and Municipal Gas has written to the President of Manitoba Hydro complaining that this public relations campaign violates the principles of consumer education established by this Board in its Order 19/00 regarding the introduction of the WTS Service and has asked for an immediate meeting with the President.

Subject to early resolution of this concern by Centra, Municipal Gas will cross-examine Centra's first Panel on this campaign, specifically Municipal Gas wants to find out why Centra is not abiding by the principles regarding consumer education, on natural gas choice set down by this Board, in its WTS Decision, and further to Municipal's Information Request No. 4 in this proceeding, how the costs of the current Public Relations Campaign are being booked and allocated by Centra.

Municipal is concerned that Centra is using ratepayer funds to promote system supply and compromise competitive retail options, contrary to the objectives of the fair and open retail market that this Board has determined is in the best interests of Manitoba's gas consumers.

Thank you.

THE CHAIRPERSON: Thank you, Ms. Melnychuk. And the last registered Intervenor here that we have on the list is Simplot Canada Limited, Mr. Gretner.

MR. BOB PETERS: I can indicate, Mr. Chairman, that I have spoken with Mr. Gretner on a couple of occasions, and that his focus for his client will be on the unaccounted for gas matter, for which, through the cooperation of Centra, we have scheduled for one (1) week from tomorrow. And so, Mr. Gretner, I will enter his appearance on his behalf today, that he will be here with his witnesses next Thursday, and he will participate in the portion of the Hearing dealing with unaccounted for gas, and also filing closing submissions.

Thank you.

THE CHAIRPERSON: Thank you, Mr. Peters. Would you now review the draft outline of procedures as circulated with the Company and the Intervenors, and seek any questions or suggestions for any changes thereto.

MR. BOB PETERS: Yes, I would be pleased to, Mr. Chairman. I have circulated in advance an outline of procedures to, I believe, all the Registered Intervenors and

I have provided additional copies this morning.

Parties will note, as they did in your Opening Comments, Mr. Chairman, that this Hearing is scheduled for September 8th, 9th and 10th, as well as September 15, 16 and 17, that is Wednesday, Thursday, Friday of this week and Wednesday, Thursday, Friday of next week. There is also Closing Submissions on -- scheduled presently for September 22nd.

In terms of the Registered Intervenors, the Board held a Pre-Hearing Conference on April the 7th, 2004, where they issued Procedural Order 65/04, and that did grant Intervenor status to the Consumers' Association, I'm sorry, the Canadian Association of Consumers of Manitoba, and the Manitoba Society of Seniors; also to Municipal Gas and Direct Energy, and to Simplot Canada, as well as MacDon Industries Limited.

The time table was established in Order 65/04 for the orderly exchange of information, and did set the commencement hearing date as I have indicated.

Now, turning to the outline of procedures that I have circulated, when we start the Hearing in terms of the witnesses, I am suggesting that Centra's Witness Panel Number 1 would start; Ms. Murphy has already introduced them. They would be examined in-chief or direct examination by Ms. Murphy; they would then be cross-examined firstly by Board

Counsel, then by Intervenors in alphabetical order, and re-examined if requested.

I should indicate, Mr. Chairman and Board Members, that in addition to Centra's first panel today, the Board can anticipate a presentation by Professor Peter Miller on behalf of Time to Respect Earth's Eco Systems, as well as Resource Conservation Manitoba; it goes by the acronym, if I have it right, as TREE and RCM, and they would like to attend after lunch today, and commence the afternoon with their presentation.

Once we finish with the presentation and this Witness Panel, after it is concluded, Centra will then call its second Witness Panel; again, Ms. Murphy has indicated the change that is planned, and the additional two (2) parties that would sit on the Witness Panel.

And likewise, that Panel would deal with cost allocation, rate design, customer impact-type issues, and they would be examined by Ms. Murphy, cross-examined by Board Counsel, and then by Intervenors.

What parties will see on the outline of procedures next, is that on Wednesday, September 15th, 2004, at 9:00 a.m., a time has been set aside for the presentation of MacDon Industries Limited, and that was referred to by Mr. Carroll in his Opening Comments. That presentation would take place first thing on Wednesday morning, one (1) week from today.

Then the Panel would, Centra’s Witness Panel would continue, and the Panel would be, if not concluded, interrupted on Thursday, September the 16th, and it would be interrupted so that the Centra Witness Panel could first give its unaccounted for gas evidence, and be cross-examined on it by Board counsel and then by Intervenors.

And once Centra has dealt with the unaccounted for gas portion of its evidence, then we would allow Simplot to call its two (2) witnesses in their panel and have them examined by Mr. Gretner, cross-examined by the Intervenors in alphabetical order firstly followed by any cross-examination by Centra and then lastly by Board counsel.

The remaining item on the Outline of Procedures, Mr. Chairman, and Board Members, is the closing comments which I indicated we have tentatively scheduled for Wednesday, September 22, two (2) weeks hence, to conclude this Hearing.

We will work towards those objectives and if there are time constraints or issues that arise, we’ll bring them to the Board’s attention and ask for the Board’s -- Board’s guidance.

I would also like to take this opportunity, on behalf of all parties, to file the exhibits that are part of this proceeding and I’ll do that in summary form that PUB

Exhibit 1 is the Notice of Hearing.

PUB Exhibit 2 would be the Reminder Notice of August 11, 2004.

Exhibit PUB number 3 would be the Procedural Order 65 of ’04 dated April 22, 2004.

And PUB Exhibit 4 is the transcript of the pre-hearing conference held April 7th.

Then Exhibits PUB/Centra 5-1 through 5-108 represent the Public Utilities Board information requests of Centra and Centra’s responses to both first and second round information requests.

--- EXHIBIT NO. PUB-1 Notice of Hearing

--- EXHIBIT NO. PUB-2 Reminder Notice of August 11, 2004

--- EXHIBIT NO. PUB-3 Procedural Order 65 of ’04 dated April 22, 2004

--- EXHIBIT NO. PUB-4 Transcript of the pre-hearing conference held April 7th.

--- EXHIBIT NO. PUB/CENTRA 5-1 TO 5-108
Public Utilities Board information requests of Centra and Centra’s responses to both first

and second round information requests

MR. BOB PETERS: In terms of Centra’s exhibits, Centra number 1 would be their application dated February 20, 2004.

Centra Exhibit 2-1 would be the affidavit of publication and service of the notice dated April 7, 2004 as indicated by Ms. Murphy in her opening comments.

Centra Exhibit 2-2 would be an affidavit of publication and service of a reminder notice dated August 31, 2004.

Centra Exhibit 3 will be their rebuttal evidence dated August 30, 2004.

The witness qualifications would be Exhibits 4-1 through to 4-7. They were filed on September 2nd by Centra.

And Centra/Simplot Exhibit 5-1 to 5-14 would be the questions that the Utility had of the witnesses for Simplot and the responses by Simplot’s witnesses.

--- EXHIBIT NO. CENTRA-1: Application dated February 20, 2004

--- EXHIBIT NO. CENTRA 2-1: Affidavit of publication and service of the notice dated April

7, 2004

--- EXHIBIT NO. CENTRA 2-2: Affidavit of publication and service of a reminder notice dated August 31, 2004

--- EXHIBIT NO. CENTRA 3: Rebuttal evidence dated August 30, 2004

--- EXHIBIT NO. CENTRA 4-1 TO 4-7: Witness qualifications

--- EXHIBIT NO. CENTRA/SIMPLOT 5-1 TO 5-14: Questions that the Utility had of the witnesses for Simplot and the responses by Simplot's witnesses

MR. BOB PETERS: The Consumers' Association of Canada and Manitoba Inc. and Manitoba Society of Seniors exhibits would be Exhibits CAC/MSOS/Centra 1.1 through 1.92 and those would be the information request posed by those Intervenors and the Utilities responses to them.

Direct Energy's exhibits, Direct Energy/Centra 1-1 through 1-4 would be the information requests posed by this intervener as well as the responses by the Utility.

--- EXHIBIT NO. CAC/MSOS/CENTRA 1-1 through 1-92:
Information Requests posed by those Intervenors and the Utilities responses to them.

--- EXHIBIT NO. DIRECT ENERGY/CENTRA 1-1 through 1-4:
Information Requests posed by this intervener as well as the responses by the Utility.

MR. BOB PETERS: For MacDon Industry Limited, their exhibits would be MacDon/Centra 1-1 through 1-12. And those would be the information requests by MacDon and Centra's responses to them.

--- EXHIBIT NO. MACDON/CENTRA 1-1 to 1-12:
Information Requests by MacDon and Centra's responses to them

MR. BOB PETERS: I should indicate that from what people may have as their typed list, MacDon/Centra 1-12 has been added. This is a response to MacDon's letter of August 19 dealing with rates and billing differences that was answered a week or two ago.

In terms of Simplot Canada's exhibits, Simplot 1-1 through 1-23 would be the information request posed by

Simplot and Centra's responses.

And Simplot Exhibit 2 would be the evidence of David Hawk and Simplot Exhibit 3 would be the evidence of Dr. Don Redding.

--- EXHIBIT NO. SIMPLOT 1-1 through 1-23:
Information Requests posed by Simplot and Centra's responses.

--- EXHIBIT NO. SIMPLOT 2: Evidence of David Hawk

--- EXHIBIT NO. SIMPLOT 3: Evidence of Dr. Don Redding

MR. BOB PETERS: Mr. Chairman, I believe I've got those exhibits to a current stage and the parties can work them. If they have any revisions or corrections they can certainly let me know and likewise, you may wish to canvas them to see if there's any concerns with the Outline of Procedures that we have prepared and circulated.

So subject to any comments you or your Board Members have of me at this time, those conclude my review of the Outline of Procedures and the exhibits. Thank you, Mr. Chairman.

THE CHAIRPERSON: Thank you, Mr. Peters. Ms. Murphy, do you have any problems or concerns with the procedure outlined by Mr. Peters?

MS. MARLA MURPHY: No, sir, we don't.

THE CHAIRPERSON: Mr. Saxberg...?

MR. KRIS SAXBERG: No.

THE CHAIRPERSON: Mr. Carroll...?

MR. BILL CARROLL: No.

THE CHAIRPERSON: Ms. Melnychuk...?

MS. KAREN MELNYCHUK: No, I don't.

THE CHAIRPERSON: Thank you. So now we'll move onto direct evidence by Centra Gas. To begin with, Mr. Singh, would you kindly have the Panel sworn or affirmed and then we can proceed to hear from them?

VINCE WARDEN, Sworn:

HOWARD STEPHENS, Sworn:

LORI STEWART, Sworn:

BRENT SANDERSON, Sworn:

DARREN RAINKIE, Sworn:

THE CHAIRPERSON: Thank you, Mr. Singh. Ms. Murphy we can begin and I just got a note that at 10:30 we'll have a short break, thank you.

MS. MARLA MURPHY: Thank you, good morning. Mr. Chairman and Members of the Board, the Centra Panel which has now been sworn consists of Mr. Vince Warden, Ms. Lori Stewart, Mr. Howard Stephens, Mr. Brent Sanderson and Mr. Darren Rainkie.

The witness qualifications of the Panel as well as Ms. Derksen and Mr. Barnlund are marked as Exhibits Centra 1-1 through Centra 1-7 respectively. These witness qualifications set out the positions of each Panel member, their experience and education qualifications, previous appearances before the Board, their area of responsibility with respect to this Application and their adoption of pre-filed evidence as it relates to their areas of responsibility.

With your leave, I'll proceed with the examination.

THE CHAIRPERSON: Please.

EXAMINATION-IN-CHIEF BY MS. MARLA MURPHY:

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

MR. VINCE WARDEN: Yes, good morning, Mr. Chairman, Members of -- of the Board, Ladies and Gentlemen. My areas of responsibility with respect to Centra's 2004, 2005 Cost of Gas Application relate mainly to policy issues and general oversight of the filing.

MS. MARLA MURPHY: Mr. Warden, you're familiar with the Application and the evidence filed on behalf of Centra Gas and marked as Exhibit Centra 1 in this proceeding?

MR. VINCE WARDEN: Yes, I am.

MS. MARLA MURPHY: And that evidence was prepared under your direction and control?

MR. VINCE WARDEN: Yes, it was.

MS. MARLA MURPHY: And is that evidence true to the best of your information and belief?

MR. VINCE WARDEN: Yes.

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

MR. VINCE WARDEN: Yes, and Mr. Peters did an excellent job as usual in providing an overview of Centra's Application so I won't go into detail. But in summary, Centra's requesting changes to its supplemental gas, transportation to Centra and distribution to Centra rates. As well as a change to the distribution rate related to unaccounted for gas to be effective November the 1st, 2004.

Centra is seeking approval to refund to customers $16.5 million accumulated in various cost -- cost of gas deferral accounts based on actual balances as at December the -- sorry, March 31, 2004 with carrying costs and rate rider amortizations to October 31, 2004.

Centra is also requesting approval for reduction in non-primary gas costs for the 2004/05 fiscal year of approximately $3.2 million over those -- those costs included in the currently approved base rates. This reduction is based on forecast of gas prices using the twelve (12) month forward strip as at July the 2nd, 2004.

If approved, these changes will result in an annual decrease to the typical residential customer of approximately 3.9 percent or fifty-two dollars ($52). Centra is not requesting any changes to its non-gas costs in this Application.

MS. MARLA MURPHY: Mr. Warden, could you please advise the Board as to Centra's plans as a result of the gas applied portfolio review or blank page analysis?

MR. VINCE WARDEN: Centra conducted a comprehensive gas supply portfolio review, or blank page analysis during 2002 and 2003. To assist with this review, Centra engaged International Gas Consulting, or IGC, and the report of IGC has been filed with these Proceedings in Tab 4.

In summary, IGC concluded that Centra's existing gas supply portfolio, which has essentially been in place since 1993, has served Centra's customers reliably and at reasonable cost.

IGC's major recommendation was that Centra migrate from the existing portfolio, over time, to a new portfolio, consisting of salt cavern storage, and expanded in our reservoir storage.

The advantages -- advantages of this optimized portfolio, according to IGC, included a greater security of supply, and a lower expected unit cost than the existing portfolio. IGC recognized that the availability of surplus capacity on TCPL, TransCanada Pipelines, is such that there is adequate time for Centra to fully consider its options before embarking on this project.

As noted in its pre-filed evidence, Centra is presently able to utilize short-term contracts for delivered gas, and can arrange exchanges of firm capacity, in order to meet its needs in a secure and economical manner. Centra has also had some discussions with TCPL as to whether some of their excess pipeline capacity could be used as virtual storage to meet Centra’s firm supply and requirements.

Because of the significant cost in developing salt cavern storage in the order of $50 million, Centra must be fully satisfied that this is the best possible solution for the gas consumers of Manitoba, both in terms of security supply and lowest net cost. We are currently in the midst of an internal analysis, and expect to have a recommendation for review by Centra’s senior management and Board of Directors, by the first quarter of 2005.

MS. MARLA MURPHY: Mr. Warden, Centra has proposed changes to the terms and conditions of service to advance its one (1) bill initiative. Could you please describe these proposed changes for the Board?

MR. VINCE WARDEN: Centra's requesting that the Board approve changes to its terms and conditions of service and terms and conditions of billing and collection services, in order to permit Centra and Manitoba Hydro to achieve substantial synergies in the combined billing of energy services.

Manitoba Hydro is currently preparing to move all electricity customers from its legacy customer system to the -- modern banner customer information system, presently used by Centra Gas. This will permit one (1) bill for customers who have both natural gas and electricity services, and will result in considerable savings for all customers.

Manitoba Hydro expects to commence issuing integrated gas and electricity bills in November of 2005. The planning and programming leading up to this implementation date requires that Centra receive approval to the proposed changes to its terms and conditions of service, as part of this Application, in order that Centra's able to meet the November of 2005 date.

One (1) of the important issues to be addressed in the programming phase relates to the fact that although approximately 85 percent of our customers pay their bills when they -- when they're due. And approximately another 10 percent pay their bills within thirty (30) days of the due date, there are some customers who do not make payment in full of their accounts, until sometime after the due date.

Centra is therefore requesting approval of changes to the terms and conditions of service, to permit the appropriate allocation of partial payments, or other credits between a customer's electricity and natural gas service.

In order to ensure consistency with Centra's terms and conditions of service, it will be necessary to amend the terms and conditions of billing and collection services that were approved by the Public Utilities Board, in Order 105/97.

The requested amendments will permit Centra and Manitoba Hydro, in the small number of cases, where payment in full is not received, to appropriately credit customers' accounts with payments received on a pro rata basis between the two (2) services. The requested amendments are detailed in Tab 9, pages 11 to 14.

This allocation process will only apply in the absence of explicit instructions from the customer. As such, where a customer designates that a payment applies to a particular service, or an allocation other than the one set out in the terms and conditions of service, Centra will honour these instructions and -- and apply the payment as directed by the customer.

MS. MARLA MURPHY: Mr. Warden, in the Reminder Notice issued for this Hearing, the Public Utilities Board indicated it wished to initiate discussions on the future regulation of Centra Gas.

Do you wish to comment on this matter?

MR. VINCE WARDEN: Yes, and this is a -- a fairly broad topic area which covers a number of issues but one (1) issue that has been of particular interest to Manitoba Hydro since the acquisition of Centra Gas is the rate-based rate of return regulation versus regulation based on cost of service.

Manitoba Hydro’s position has been, and is, that both gas and electric rates -- rates should be based on the cost of service model which we believe to be the most appropriate rate setting methodology for a Crown owned utility.

Manitoba Hydro is also of the view that until appropriate legislative changes are made to permit the regulation of Centra Gas under the cost of service methodology, there is discretion for the PUB to -- satisfy its current legislative requirements by ensuring that the contribution to retained earnings under the cost of service methodology does not exceed the allowed rate of return under rate-based rate of return methodology.

And based on the current financial information at Centra Gas we expect to be appearing before the Public Utilities Board in the late fall or early winter with the General Rate Application for new distribution rates to be effective April 1, 2005.

Given the express desire of the Board Chairman as set out in the letter of April the 30th, 2004, Centra proposes that the GRA be filed under the current legislation which would include -- and include calculations for both rate-based rate of return and cost of service. And this would allow the Board to satisfy its legislative requirements and permit the comparison of the two (2) methodologies based on actual circumstances prevailing at that time.

MS. MARLA MURPHY: Mr. Warden, are there any other issues to be addressed in this Application?

MR. VINCE WARDEN: Yes, there are a number of other issues which the other Panel members will address briefly in their direct testimony. Thank you.

MS. MARLA MURPHY: Thank you, Mr. Warden. 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 Board, Ladies and Gentlemen. In my testimony I will be providing evidence with respect to Centra’s derivatives hedging program and its results as well as the market research with respect to customers’ perceptions and preferences regarding primary gas price volatility. I will also be addressing issues that may arise with respect to the Western Transportation Service.

MS. MARLA MURPHY: Ms. Stewart, would you please outline Centra’s derivative hedging activities since Centra last appeared before the PUB in the 2003/’04 General Rate Application.

MS. LORI STEWART: All of the financial instruments purchased since last year’s GRA were purchased in accordance with the approved derivatives hedging policy and operating principles and procedures. All hedges purchased were fifty (50) cent out of the -- out of the money cashless collars on 90 percent of eligible volumes. Accordingly there were no prepaid premiums -- or prepaid premium costs associated with the transactions.

The impact of Centra’s hedging transactions on its gas costs will be referred to by Mr. Sanderson in his direct evidence. Notwithstanding the reduction in gas costs that Mr. Sanderson will outline, Centra considers the percentage reduction in primary gas rate volatility as the appropriate measure in determining the success of the hedging program.

As noted in the response to CAC/MSOS Centra 43, the reduction in volatility achieved during the 2003/04 fiscal year was 20 percent. Year to date 2004/05 -- that is the period from April 1st, 2004 to October 31st, 2004 -- the reduction in primary gas rate volatility as a result of the hedging program is 33 percent.

MS. MARLA MURPHY: Ms. Stewart, could you please outline why Centra undertook its recent market research on customers' perceptions and preferences related to the primary gas price volatility?

MS. LORI STEWART: Centra indicated to the Public Utilities Board at the 2003/04 General Rate Application that it intended to undertake market research on customers' perceptions and preferences related to primary gas price volatility, as its then current research had been undertaken in 1998. In late 2003, Western Opinion Research conducted four (4) focus groups, and used the output from those focus groups to design a telephone survey, which was conducted in January 2004.

The report on research results was completed in March 2004, and is filed as an attachment to the Response to PUB Centra 9(a).

MS. MARLA MURPHY: Ms. Stewart, can you please outline the results of that report, as it relates to the derivatives hedging policy, and its impact on the derivative hedging policy and procedures.

MS. LORI STEWART: In the study, 53 percent of respondents indicated that they would like to see the current level of hedging maintained. An additional 13 percent of respondents indicated that they wished to see an increase in hedging activities.

Given that approximately two-thirds (2/3) of respondents indicated that they would like to see the current levels of hedging either maintained or increased, Centra is not proposing any changes to its derivatives hedging policy.

The current hedging program appears to strike an appropriate balance between market responsiveness and price volatility.

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

MR. HOWARD STEPHENS: Certainly. Good morning, Mr. Chairman, Members of the Board, Ladies and Gentlemen.

In my testimony I will be providing evidence on Centra’s gas supply, storage and transportation arrangements, the gas supply per quota review, and Centra’s Capacity Management Program and results.

MS. MARLA MURPHY: Mr. Stephens, there have recently been changes to Centra’s primary gas supply contract; could you please discuss how these changes came about.

MR. HOWARD STEPHENS: Centra's current primary gas supply contract with Nexen Energy Marketing, will expire on October 31st, 2004. A comprehensive Request for Proposal, RFP, describing Centra's natural gas supply requirements, was sent to twenty (20) major natural gas suppliers/marketers, on January 9th, 2004. Nine (9) responses were received, a summary of which is provided at Attachment 5 to Tab 3.

Following a comprehensive review of each proposal, Nexen was determined to have the most attractive offer, and as such, is the preferred supplier. Nexen has demonstrated its ability to accommodate Centra's highly variable load during the current contract. Nexen's proposal provided the most attractive pricing provisions and the flexibility to accommodate variations in Centra's daily load, and adjustments to accommodate Centra's western transportation service.

Nexen indicated that its pricing proposal was dependent upon it receiving a contract for the full quantities, and that a premium would be added if the contract was for lesser quantities. Because Nexen had a commanding lead in the evaluation matrix, and because the contract being negotiated was for a three (3) year term, a single supplier was considered appropriate.

MS. MARLA MURPHY: Mr. Stephens, can you please outline the key features of the Nexen contract?

MR. HOWARD STEPHENS: The proposal submitted by Nexen provides a flexibility very similar to that which Centra currently enjoys.

Under the existing contract, Centra has the ability to adjust its nominations for any given day, several times throughout the day, to reflect changing weather conditions. In addition, Centra has the ability to revise its system requirements each quarter, to reflect any changes to quantities supplied by brokers.

From a pricing perspective, Nexen was the most attractive of all the supplier proposals received. The salient of the Nexen contract are: a firm caseload supply component that does not have any price premium over index, and as such will be priced directly to the Alberta AECO index, base load quantities, which have 100 percent load factor commitment attached to them, can be adjusted to each quarter, fifteen (15) days prior to the expiry of the prior quarter; this remains unchanged from the current contract, and enables Centra to accommodate WTS purchases.

A two-tiered firm swing supply component provided Centra with the ability to make changes to the quantities nominated several times over the course of the day to account for changing weather conditions.

Priced at AECO daily index plus two and a half (2 1/2) cents per GJ for the first eighty thousand (80,000) Gigajoules per day, nominated, and at AECO daily index plus five (5) cents per GJ for quantities between eighty thousand (80,000) Gigajoule per day and a hundred and twenty thousand (120,000) Gigajoules per day.

The incremental cost of this rate revision is approximately four hundred thousand dollars ($400,000) per year. AECO to Empress -- TCPL Transportation is billed on an as-used basis as opposed to an as-billed basis. A three (3) year term with an option to extend for an additional one (1) or two (2) year term. And all quantities purchased are restricted for use by customers in Centra in the Centra delivery area, depending upon market circumstances.

This may reduce capacity management revenues by approximately two hundred and fifty thousand dollars ($250,000) per year.

MS. MARLA MURPHY: Mr. Stephens, can you please advise the Board as to the changes to the Trans-Canada Pipelines contract for natural gas transportation?

MR. HOWARD STEPHENS: Centra's current contractual arrangements with Trans-Canada Pipelines for firm service have been in place since January 1st, 1989 and terminated on December 31st, 2004.

On May 25th, 2004, Centra advised TCPL of its intention to renew the two (2) existing firm service transportation contracts which provide for the transportation of natural gas from Empress, Alberta, to the Manitoba delivery area and the Saskatchewan delivery area, sister of the market.

The daily contract quantity of the Manitoba delivery area firm service transportation contract, and that's a multiple, was reduced slightly to -- to accommodate the firm service contract with Centra to consignment of, as part of the acquisition of the Gladstone Austin Natural Gas Co-op.

No changes were made to the Saskatchewan -- delivery area firm service transportation and contract. Both contracts were renewed for twenty-two (22) months, terminating on October 31st, 2006, the minimum term provided by -- by TCPL which would allow for termination coincident with the end of the gas year, i.e., November 1st through October 31st.

The short term renewal provides Centra with the opportunity to alter -- alter its transportation portfolio should more attractive services become available from Trans-Canada, and preserve Centra's right of first refusal for the contracted capacity upon expiry of the reviewed -- renewed contracts.

TCPL's storage transportation service contract that expires on March 31st, 2005 has also been renewed for one (1) year.

MS. MARLA MURPHY: Mr. Stephens, could you also please summarize the changes which have been made to the ANR and GLGT contracts for storage and transportation services?

MR. HOWARD STEPHENS: I hope everybody's comfortable. In 1993, Centra Gas entered into a twenty (20) year arrangement with ANR for a bundled package of storage and transportation services to meet Manitoba's gas supply requirements.

ANR contracted on Centra's behalf for the -- for capacity on the Great Lakes system. This asset makes us serve Manitoba consumers reliably and economically for the past decade.

The service is provided directly by ANR; we're subject to an annual revenue cap of $14,767,00 US per year for the term of the agreement.

ANR had the right to adjust the rates for transportation and storage provided that, using the design volumes, ANR's total projected revenues for all transportation and storage services did not exceed the revenue cap.

The rate -- rates for the services ANR

contracted on Centra’s behalf with GLGT for both forward haul and back haul are based on a declining cost of service methodology, amortized over twenty (20) years and the resultant costs were passed through to Centra with no mark up or discount by ANR.

ANR proposed the revised contract incorporate reservation charges fixed at levels which, going forward, would result in the lesser of the stated rates which equate to the revenue cap or -- or the tariff rates.

It was -- it was also proposed that the GLGT firm forward haul and the interruptible back haul contracts previously held by ANR on behalf of Centra be permanently assigned to Centra.

The new ANR contracts contain a standardized unilateral rate adjustment clause which provides a mechanism to ensure that the over -- agreed overall rate is maintained. Centra also obtained a letter from ANR recognizing the historical intent of the arrangements and a stipulation that the revenue cap would not be exceeded in the future.

Centra also signed contracts directly with Great Lakes Gas Transmission for both its forward haul and back haul requirements. The previous back haul service was provided on an interruptible basis and has been replaced with a firm back haul service coincident with the remaining term of the storage arrangement, September 1st, 2004 until March

31st, 2013.

The terms of the firm back haul service arrangement mirror the terms of the previous interruptible back haul contract held by ANR.

The terms of the forward haul contract with GNL -- GLGT remain unchanged except that they -- the contract is now held directly by Centra.

Changing the back haul service from -- from interruptible to firm will result in a cost increase of approximately two hundred thousand dollars ($200,000) US per year, relative to the current pricing.

Realignment of the contracts through March 31st, 2013 will provide greater rate certainty for the back haul service, by avoiding the potential exposure to paying un-discounted rates.

When originally signed, contracting with GLGT for back haul service on an interruptible basis was viewed as comparable to a firm contract, as long as sufficient quantities were shipped by others under -- under firm forward haul transportation contracts.

Contracting for firm back haul service for Centra at this point eliminates any concerns about potential rate changes arising from other parties de -- de-contracting or GLGT filing a new tolling application.

The long term firm discounted back haul

service will ensure that Centra will be access its storage gas without interruption for the remaining term of the contract with price certainty.

MS. MARLA MURPHY: Mr. Stephens, can you please describe for the Board the purpose of Centra's capacity management program?

MR. HOWARD STEPHENS: Certainly. Centra's capacity management program should be viewed as an integral component of its overall portfolio management activities.

The purpose of this program is to mitigate the costs of the assets under contract that are required to serve Manitoba gas consumers. Centra's first priority, however, is to ensure that the requirements of our customers are satisfied before any capacity management transactions are considered.

MS. MARLA MURPHY: What factors determine whether Centra is able to enter into a capacity management transaction?

MR. HOWARD STEPHENS: There are a number of variables outside of Centra's control that influence the volume of activity as well as the revenue that is generated by Centra's capacity management program.

There must be an asset that is temporarily not required to serve our customers and there must be an alternate -- alternate market that can utilize that asset at a price that generates a profit to Centra.

Also, there must be an ability to access that market through the use of our storage and pipeline facilities. Weather also -- is also a significant variable that impacts Centra's capacity management activities and revenues.

The weather determines the level of capacity that may be in excess of that needed to serve the Manitoba market and the amount of capacity that may be released for a capacity management transaction. The weather also influences the demand for our excess capacity in other market locations.

Another significant variable influencing Centra's capacity management program is the price that the market is willing to pay for any excess capacity Centra may have to offer.

When these variables all come together in a manner in which -- a benefit may be derived for Centra's customers, Centra enters into a transaction.

MS. MARLA MURPHY: Mr. Stephens, would you please summarize the capacity management revenues for the 2003/04 fiscal year and the forecast for the 2004/05 fiscal year?

MR. HOWARD STEPHENS: For the 2003/04 fiscal year, actual capacity management revenues together with carrying costs total approximately $6.3 million as shown on the updated Schedule 5.3.1.

Centra generated net revenues of approximately $4 million through capacity release and approximately $1.9 million in exchanges.

The balance of the capacity management revenue, approximately two hundred and seventy-three thousand dollars ($273,000) arose through the re-sale of contract -- Centra contracted supplies with Nexen.

It should be noted that there are also circumstances, and I can't emphasise this enough, where certain capacity management transactions can be utilized to serve market requirements during cold periods, thereby resulting in avoided costs which are not captured as capacity management revenues.

For the 2004/05 fiscal year, Centra has forecast capacity management revenues of $3.2 million based upon the most -- recent five (5) year rolling average of Centra's actual capacity management results.

These forecasts amounts have been included as a reduction to the requested rates for November 1st, 2004, and as I've indicated in previous proceedings before this Board, our staff avail themselves of every opportunity to market in the market place or that the market place allows to enter into capacity management transactions for the benefit of our customers.

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

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 Gas's costs for the period April 1st, 2003 to March 31st, 2004, as well as the related PGVA and other gas cost deferral balances, and derivatives hedging results for the period from April 1st, 2003 to March 31st, 2005.

I will also be providing evidence with respect to Centra's gas costs forecast, for its 2004/2005 fiscal year.

MS. MARLA MURPHY: One (1) of the approvals that Centra is seeking is final approval of gas costs for the period April 1st, 2003 to March 31st, 2004. 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 of $368.4 million for the period April 1st, 2003 to March 31st, 2004, as summarized on Schedule 5.0.0 in Centra's updated Application of August 9th, 2004. This includes a reduction in gas costs of approximately $4.6 million, as a result of Centra's derivative hedging activities for the 2003/2004 fiscal year.

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

MR. BRENT SANDERSON: Centra is requesting final approval of all non-primary gas PGVA and gas cost deferral balances to March 31st, 2004, with carrying costs and amortization of currently approved rate riders to October 31st, 2004, totalling approximately $16.5 million owing to customers, as per updated Schedule 5.1.0.

This balance includes the refund of forecast capacity management revenues for 2004/2005 as was referred to by Mr. Stephens, of approximately $3.25 million.

MS. MARLA MURPHY: Mr. Sanderson, would you please provide the Board with an update of the gas costs sought by Centra in this Application for 2004/2005?

MR. BRENT SANDERSON: On August 9th, 2004, Centra also filed an update of its forecast gas costs for 2004/2005, based on the forward strip price, as of July 2nd, 2004. The resulting gas cost forecast for 2004/2005, is $420.5 million, as per updated Schedule 6.2.3. This includes an expected reduction of $19.9 million in gas costs as a result of Centra's derivative hedging activities, for the 2004/2005 fiscal year.

Of the $420.5 million gas cost forecast for

2004/2005, approximately $83.4 million is non-primary gas costs. This amount represents a decrease of approximately $3.2 million from the non-primary gas costs included in existing base rates, as shown on the updated Schedule 6.2.4.

MS. MARLA MURPHY: Thank you Mr. Sanderson. Mr. Rainkie, would you please outline your areas of responsibility with respect to this filing?

MR. DARREN RAINKIE: Good morning, Mr. Chairman.

(BRIEF PAUSE)

MR. DARREN RAINKIE: Good morning, Mr. Chairman, Members of the Public Utilities Board, Ladies and Gentlemen.

In my testimony I will be responding to questions related to Centra's Letter of Application, including the confirmation of interim orders and the removal of income taxes from Centra's feasibility test.

MS. MARLA MURPHY: Mr. Rainkie, would you please outline the interim orders for which Centra seeks final approval in this Application?

MR. DARREN RAINKIE: In this Application, Centra is seeking final approval of the supplemental gas transportation and distribution sales rates, effective August

1st, 2003, approved on an interim basis, in Order 125/03. Centra is also seeking final approval of interim ex-parte orders 119/03, 116/03, 11/04, 69/04 and 100/04, related to the approval of interim primary gas sales rates effective August 1, 2003; November 1, 2003; February 1, 2004; May 1, 2004; and August 1, 2004; respectively.

Centra is also requesting final approval of Interim Order 143/03 in which the Public Utilities Board approved amendments to the primary gas rate setting process and minimum filing requirements.

Centra is also seeking final approval of Interim Ex Parte Orders 120/03 and 121/03 which approve the amended franchise agreements and feasibility tests for the extension of gas service to certain customers in the rural municipality of Rockwood and the rural municipality of Hamiota. And Interim -- Ex Parte Order 44/04 related to the changes to the terms and conditions -- conditions of service to include an additional atmospheric pressure zone.

MS. MARLA MURPHY: Mr. Rainkie, Centra has requested approval to remove the income tax component from Centra’s feasibility test which is used to assess the financial feasibility of a proposed expansion to a new franchise area or a main extension.

Could you please outline the details of Centra’s request?

MR. DARREN RAINKIE: The purpose of the feasibility test is to project the interim -- incremental costs and revenues of each expansion project or main extension and to determine if a customer contribution is required to make the project or extension financially feasible.

Centra is no longer subject to income taxes and as such, there is no incremental income tax cost for expansion projections or main extensions, and as such, it is appropriate to remove this component from the feasibility test.

Additionally, in Order 118/03, it was also resolved that the one (1) time tax payment that was made by Centra to become nontaxable would be recovered through sales rates -- customer sale rates -- over a thirty (30) year amortization period. Given the resolution of the recovery of the one (1) time tax payment, Centra now requests approval to revise the feasibility test to remove the income tax expense component.

Centra requests that these changes be made effective January 1, 2004 and that they apply to all new expansion projects and new main extensions approved by management after that date. In addition, Centra is proposing that income taxes be removed from feasibility true-ups (phonetic) required under contract for calendar periods after

January 1, 2004.

For these true-ups, income tax would be included in the feasibility tests for all calendar periods up to and including December 31, 2003 and would be removed for all calendar periods commencing January 1, 2004.

MS. MARLA MURPHY: Mr. Rainkie, are there other approvals which Centra's requesting?

MR. DARREN RAINKIE: Yes, in addition to those approvals outlined by Mr. Warden and Mr. Sanderson, Centra's also requesting approval to refine the allocation of unaccounted-for gas to various customer classes as part of the process of calculating sales rates.

Approval to implement the billing of the man-related costs for the high volume firm class based on actual peak day on November 1st, 2004, and approval to make miscellaneous adjustments to the terms and conditions of service. These matters will be addressed by Ms. Derksen and Ms. -- Mr. Barnlund in their testimony later next week.

MS. MARLA MURPHY: Thank you, Mr. Rainkie. Mr. Chairman, that concludes out direct evidence and the Panel's available to be cross-examined.

THE CHAIRPERSON: Thank you, Ms. Murray. I think what we'll do, we'll have our break now Mr. Peters and then we'll start -- be back in about ten (10) minutes.

--- Upon recessing at 10:20 a.m.
--- Upon resuming at 10:34 a.m.

THE CHAIRPERSON: Okay, Mr. Peters, do you want to --

MS. KAREN MELNYCHUK: Mr. Chairman, may I interrupt? Sorry.

THE CHAIRPERSON: Please.

MS. KAREN MELNYCHUK: I just wanted to note that we have provided a copy of our letter from Stikeman Elliott to the Board and that there's further copies on the back table for other -- other members, and that Mr. Brown will enter it as an exhibit tomorrow, if that's okay with the Board.

THE CHAIRPERSON: That's fine. Or we could give it an exhibit number now, what you do think, Mr...?

MR. BOB PETERS: I think unless there's objection from Ms. Murphy we can -- we can accord it the next exhibit which, quite frankly, I don't know what it is for Direct and Municipal. It would be Number 2, if that's --

MS. MARLA MURPHY: We have no objection.

--- EXHIBIT NO. DIRECT ENERGY/MUNICIPAL GAS-2:
Copy of letter from Stikeman Elliott

THE CHAIRPERSON: Okay, we've entered it as an exhibit. It'll make it easier when he arrives.

MS. KAREN MELNYCHUK: Thank you, sir.

THE CHAIRPERSON: Mr. Peters...?

CROSS-EXAMINATION BY MR. BOB PETERS:

MR. BOB PETERS: Yes, thank you Mr. Chairman and Board Members. When the microphones shut down and the Board is left to deliberate, I want them to be clear as to the requests that are being made of them and I'd like to start off my questioning of the Panel and it's open to all panel members, of course, as -- as usual, to run through -- and I'll stress the run through, the Application requests.

Mr. Rainkie, I may pick on you, because I think you said you were responsible in your direct evidence, for -- for general over -- over part -- overview of it and ...

So let's start off -- and it may be beneficial, Mr. Chairman and Board Members, to refer to a Book of Documents that the Advisors took the liberty of preparing to utilize with this Panel; not to say it's complete, not to say it's totally accurate but it's got some -- some documents that, if the Board can follow along, we hope to make your task easier as you noted in your opening comments, Mr. Chairman, so that when you do deliberate, you'll have the issues before you.

Mr. Rainkie, I'll start with you, then, and Tab 1 of the Book of Documents that have been prepared for Board Counsel. And let's run through your summary -- the summary of your Application.

The main thrust of why you're here is you want new rates effective November 1st for your non-primary gas. Have I got that right?

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

MR. BOB PETERS: And going forward, those are for the supplemental gas, the transportation and the distribution to Centra?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: And when we say "distribution", Mr. Rainkie, I said in my opening comments, and I hope I'm correct and you'll tell me, that that refers only to the unaccounted-for gas component of the distribution costs?

MR. DARREN RAINKIE: That's the only component that we're asking to change in this Application. Of course the distribution rate would still have the operating costs of the Company included.

MR. BOB PETERS: And if I heard Mr. Warden correctly, the distribution costs will be before this Board by way of a General Rate Application late this fall?

MR. DARREN RAINKIE: I think that's the expectation. I think that's always subject to our Board of Directors, of course.

MR. BOB PETERS: Thank you. And those -- those new rates going forward, Mr. Rainkie, commencing November 1st, 2004, would be considered new base rates for those three (3) components. Is that correct?

MR. DARREN RAINKIE: That's correct. We are also, of course, refreshing the rate riders, but I'm sure you'll get to that in due course.

MR. BOB PETERS: All right, we -- we'll -- we'll try to straighten that out. Now, going to the next component, also on Tab 1 of the Book of Documents that's been circulated, and I've copied Tab 2 from your Application and Item Number B was you want final approval of the gas costs that were incurred last year, and those gas costs are both the primary gas and the non-primary gas costs?

MR. DARREN RAINKIE: That's correct. It's our total gas costs.

MR. BOB PETERS: And if -- I believe Mr. Sanderson gave the Board the -- the numbers before. What's noted on -- in Tab 1 of the Book of Documents that I've circulated is a number that's incorrect and the final approval number is $368.4 million, if I have heard that correctly.

MR. DARREN RAINKIE: That’s correct. The -- the number was correct when we first filed the application. It was the estimate but it’s been updated to actual now to 368.4 million as per Schedule 5.0.0.

MR. BOB PETERS: All right. Thank you, Mr. Rainkie. And then going through to the next approval for the PGVA balances and the non-primary -- sorry, on the gas cost deferral accounts, you’re looking for approval of those balances as of March 31st and now with carrying costs, all the way through to October 31 of ’04.

MR. DARREN RAINKIE: That’s correct; carrying costs and rider amortization to October 31st, 2004.

MR. BOB PETERS: Mr. Rainkie, I had it somewhere else in my notes, but maybe you can help me with the rider amortization, and I hope I am not getting too deep on this; did not the rate riders come off on August 1st, 2004?

MR. DARREN RAINKIE: That -- that’s correct, Mr. Peters, but the deferral balances are the final balances at March 31st, 2004, so we have to account for the rate rider amortization between March 31st, 2004, and July 31st, 2004, when those riders came off.

MR. BOB PETERS: What you’re telling the Board, Mr. Rainkie, is that the rate rider was not charged after August 1st of 2004, in accordance with the Board Order?

MR. DARREN RAINKIE: That's correct. We had to account for the period, though, between the end of that deferral account, and when the rate rider actually came off.

MR. BOB PETERS: All right. In terms of, the next approval was to -- not only did you tell me you want approval of the amounts that are in the deferral accounts, you're also asking in Item Number D, on page 205 of Tab 2 of your February 19th filing, you wanted approval as to how you're going to dispose of those balances, and that is -- what you're telling the Board is you want to refund those to customers?

MR. DARREN RAINKIE: That's correct. And that amount is a -- is a refund to customers.

MR. BOB PETERS: And, instead of refunding over a twelve (12) month period, you're asking this Board to approve a shorter time frame, and that is to refund over a nine (9) month period?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: Can you tell the Board why you picked a shorter refund period than initially proposed?

MR. DARREN RAINKIE: The -- the practise, at least in the last two (2) or three (3) years, has been to change our non-primary gas rates on August 1st of the year, it just fits well with the timing of the filing of the

Application and the Hearing and the Order, et cetera.

So what we're trying to do is line up the expiry -- we're anticipating what's going to happen next year, and we're trying to line up the expiry of the rate riders proposed in this Application, with perhaps a 2005/06 GRA or a 2005/06 Cost of Gas Application.

MR. BOB PETERS: And what you're then trying to do, Mr. Rainkie, is to be able to put into place new rates on August 1st of '05, whether they're just for cost of gas or whether they're a general rate application?

MR. DARREN RAINKIE: That would be the intention, yes.

MR. BOB PETERS: All right. Moving on, final approval is being sought for the supplemental gas, the transportation and the distribution sales rates that were effective August '03, that were approved on an interim basis in Order 125/03?

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

MR. BOB PETERS: And that was an order from the GRA and it was interim because the gas costs at that time were forecast and were not finalized?

MR. DARREN RAINKIE: I'm going to say yes to the second part. I'm not exactly sure why those rates were approved on an interim basis, given that we had a full GRA

Hearing to develop them in the first place, but, but I'll -- I -- I just -- I don't think anything hangs on it; we're here to finalize that order right now.

MR. BOB PETERS: Okay. Mr. Rainkie, just backtracking one question here: you were looking to have the rates perhaps refreshed August 1st, 2005 if I understood your previous answers to me, and that would be by way of either another Cost of Gas Hearing or a General Rate Application; is that correct?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: In the gas industry, Mr. Rainkie, it's my understanding that the gas year is considered November 1st of a given year, to October 31st of the following year; is that your understanding?

MR. DARREN RAINKIE: That's my understanding, yes.

MR. BOB PETERS: Can you explain to the Board why you wouldn't try to line up your gas rate changes on November 1st of every year as opposed to August 1st of each year?

MR. DARREN RAINKIE: Well, while the gas year may be November 1st to October 31st, our fiscal year, of course, is April 1st to March 31st, and particularly with the implementation of -- of a rate change coming out of a general rate application, we would like to get that rate change as early as we can in the fiscal year.

It's a bit of -- I think the August 1st time frame is just a bit of history, it's kind of how it's worked in the last two (2) or three (3) years. It -- it with the Board schedule and our schedule and when our forecasts are put together in -- late in the fall and how long it takes to get to a hearing et cetera.

It seems that August 1 is -- is a decent implementation date and it's not that far off from April 1 and we try to line up most of our rate changes on the primary gas rate setting months so that there isn't a rate change between the gas quarters.

I'm not sure if that's giving you what you want, but that -- that's historically been the rationale for August 1st versus November 1st where it works well with all of the schedules and it -- it seems to get the increase or the decrease in as soon as we can the fiscal year.

MR. BOB PETERS: Okay, that's fair enough. Moving on, Mr. Rainkie, you are looking for final approval of Interim Ex Parte orders and you listed them in your direct evidence going back to August 1st of 2003, all the way through to August 1st, 2004. Have I got that right?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: And with respect to the -- we're -- we're talking here primary gas orders and you're not proposing in this Application to change the primary gas rate, but you do want approval of the orders of this Board that fixed the primary gas rate on those orders?

MR. DARREN RAINKIE: That's correct. The rate setting methodology for primary gas contemplates interim rate changes and then a cost of gas hearing later on to review and make those changes final.

MR. BOB PETERS: In terms of the quarterly primary gas rates that have been set, Mr. Rainkie, for May 1 of 2004, would you or Ms. Stewart or Mr. Sanderson be able to tell the Board whether or not the derivative products that were placed have all matured or crystallized at this point in time or are there any yet to be determined for the May 1, 2004 primary gas rates?

MR. DARREN RAINKIE: At this point there would be outstanding derivative products for the months of October 2004 through April 2005 which have yet to mature or yet to expire, for which we do not know with certainty at this point what the ultimate result will be of those transactions.

MR. BOB PETERS: All right then so, for the primary gas, Mr. Sanderson, that was consumed in May and June and July of 2004, all of the derivative products would have matured and -- and the final prices for that gas would now be known?

MR. DARREN RAINKIE: That's correct.
MR. BOB PETERS: And with respect to the rates that this Board approved on August 1 of 2004, you're telling the Board that their last primary gas rate order still has some uncertainty in it because the final gas costs for October and November -- for October in any event, have not yet been settled?
MR. BRENT SANDERSON: Yes, that's correct.
MR. BOB PETERS: Mr. Rainkie, back to you, the Board made some amendments to the primary gas rate setting process and the minimum filing requirements in its order 143/03 and the Corporation is now seeking to finalize that order?
MR. DARREN RAINKIE: That's correct.
MR. BOB PETERS: Do I take from your seeking to finalize that, Mr. Rainkie, that order had to do with the removal of the requirements on Centra to file impacts on a 25, 50, and 75 percent of the difference basis, that was one of the changes?
MR. DARREN RAINKIE: That's correct.
MR. BOB PETERS: And likewise there was no required update ten (10) years before the end of the -- or ten (10) days before the end of the month?
MR. DARREN RAINKIE: That -- that was the other change in that decision.

MR. BOB PETERS: And -- and by your asking this Board to finalize it, are you telling the Board that you're in agreement with that and you're finding that it's working properly or is there areas of concerns with that order?

MR. DARREN RAINKIE: I think we're -- we're pleased with that. The purpose of that of course was to eliminate the customer confusion of filing an initial application, having a notice that went out to customers saying here is the impact of the rate change, and then lo and behold just a few days before the actual implementation of that rate changing -- for the most part the Board had accepted the update and not the original application so we were changing the rate from what had been published.

So I think we're more than pleased with that -- that procedural change.

MR. BOB PETERS: You're telling the Board that there hasn't been confusion then from the customers over the amount of the rate change and that's the primary reason that it -- it's working well?

MR. DARREN RAINKIE: I think that's correct. I -- I'm unaware of any negative reaction of the customers of -- of making the change and not having the update. We haven't received any correspondence to that effect.

MR. BOB PETERS: All right, Mr. Rainkie,

moving to the next area, when Centra expands its service territory to an area that is not covered by an existing franchise, Centra will file with this Board a request to amend their franchise and to provide service to an expanded customer base. Is -- is that correct?

MR. DARREN RAINKIE: Yes, I believe that's required under Section 69 of the PUB Act.

MR. BOB PETERS: For an accountant, that's not bad, Mr. Rainkie, but we'll - we won't hold that against you if you're wrong.

What you're telling the Board, Mr. Rainkie, is that when you come to the Board looking for approvals you've usually got the -- you have to have in hand the -- the consent of the franchise granter and that is usually the municipality?

MR. DARREN RAINKIE: That's right. We need the right to distribute in that -- in that area; that's through the Franchise Agreement.

MR. BOB PETERS: And the two (2) orders that you are seeking final approval of are the R.M. of Rockwood expansion and the R.M. of Hameota expansion, Mr. Rainkie?

MR. DARREN RAINKIE: That's correct.

Those -- those were what I call the small expansions that were done on an Interim Ex Parte basis and we're now coming at our earliest opportunity in a public hearing to -- to try and finalize those.

MR. BOB PETERS: And maybe by covering it now I won't need to cover it later, Mr. Rainkie, those -- when you say small expansions, there was really one (1) or two (2) customers in each expansion if I recall?

MR. DARREN RAINKIE: That's right. I think there was -- in one (1) there was one (1) residential customer and -- and the other there was one (1) commercial customer.

MR. BOB PETERS: And in those circumstances you prepared a feasibility test that has the currently Board approved methodology?

MR. DARREN RAINKIE: In the one (1) circumstance it was a main extension so we prepared a feasibility test. In the other circumstance it was an attachment to an existing main so our excess footage charge and customer contribution schedule came into effect.

MR. BOB PETERS: And in those circumstances, Mr. Rainkie, if any contributions were required from the customer or third parties, those contributions have been received?

MR. DARREN RAINKIE: Yes, Mr. Peters. I think there was an information request that laid out that -- the receipt of those monies.

MR. BOB PETERS: Are there any other

expansions that have been done by way of Interim Ex Parte orders, Mr. Rainkie, that are outstanding.

MR. DARREN RAINKIE: No. I think this -- this is -- these are the -- the two (2) that are outstanding in interim at this point.

MR. BOB PETERS: All right. You also have indicated in the evidence that Centra wants to seek this Board's approval to refine the allocation of the unaccounted-for gas cost to various customer classes as part of the process for calculating the sales rates, correct?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: And this is a topic that will be discussed on Thursday, August 16th, in the presence of Simplot's counsel and their witnesses. Is that your understanding?

MR. DARREN RAINKIE: That's my understanding, yes.

MR. BOB PETERS: In addition, Mr. Rainkie, you're seeking approval for the billing of demand-related costs for the high volume firm customer using actual demand as opposed to the average demand. Have I got that right?

MR. DARREN RAINKIE: That's right.

MR. BOB PETERS: Now, Mr. Rainkie, if memory serves me, we've tripped over this once before in various ways. Can you tell the Board when you are -- what is the time period in which you are measuring the demand -- or proposing to measure the demand -- and what is the time period in which you propose to commence the new demand charge?

MR. DARREN RAINKIE: I think you're the best that I have in terms of a cost allocation person right now but hopefully Ms. Derksen can read the transcript and clean it up if I'm not 100 percent technically correct.

One of the -- one (1) of the things to keep in mind is that when we filed -- I think it was Section 7.6, the so-called additional HVF demand evidence -- we changed our proposal slightly from what was outlined in the letter of application that you have in Tab 1 of your book of documents.

We started out by saying that we were going to implement HVF demand billing on November 1, 2004 based on the demands that had been set in the previous year, 2003/04. In -- in looking at the timing of the implementation of the rates and -- and -- and some of the information that was coming out of, I think it was Order 16/04 and 45/04, related to this matter.

We made a -- a slight change in that we would -- we're proposing to implement actual demand billing on a prospective basis so the customers would continue to be billed on their average demand up until November 1 and up until the time that they -- that their next peak day was set

-- that we would start billing actual peak day when they set their -- their next demand in the November 1st, 2004 to March 31st, 2005 period.

That’s about the extent of my understand. It gets fairly complicated with the demand rachet -- the twelve (12) month demand rachet but -- but I think this is where we got tripped up the last -- the last time in -- in the -- in the 2003/04 GRA is that we were -- we were looking to implement this on a prospective basis and I think the Board took that as meaning, while we were waiting to the end of the next winter period to start and what we were saying is -- is what we’re doing is we’re trying to say to the customer, rather than taking your peak from 03/04 and -- and -- and using that actual peak for the forward looking billings, we’re going to allow you to set a new peak.

If you can make some changes in your operation to mitigate the effects of our proposal in the 04/05 period, then -- then we’re not going to -- I won’t use the word "penalize" you, but we’re not going to go back to what you did in your 03/04 and the 03/04 winter.

So it’s very important, I think, that we understand that this is to be implemented on a prospective basis and I’m sure we’ll have lots of opportunity to go through that with Ms. Derkson because that’s where, I think, we got tripped up -- tripped up the last time.

MR. BOB PETERS: Thank you for that, Mr. Rainkie, for clarifying that and that's a matter that we'll address with your second panel and get more details for the Board and also for, perhaps Mr. Carroll and others who are interested in that matter.

The filing you have before us, Mr. Rainkie, asks this Board to amend the terms and conditions and that's a matter again that Ms. Derkson will -- will address in the second panel?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: And in terms of removing Income Tax component from the feasibility test, that's an area that you're prepared to speak to with this panel, correct?

MR. DARREN RAINKIE: I can do it in either panel, Mr. Peters.

MR. BOB PETERS: Well, let's ask questions while we've got you on this panel, Mr. Rainkie, so we can ask the real ones later. See if you -- see if you give us the same answer.

What you're asking the Board is, when you do your feasibility tests for a system expansion, you want to remove the Income Tax component?

MR. DARREN RAINKIE: That's correct, effective January 1st, 2004.

MR. BOB PETERS: And you want to remove, in essence, retroactive to the beginning of this calendar year?

MR. DARREN RAINKIE: That’s correct.

MR. BOB PETERS: The removal of the Income Tax component, Mr. Rainkie, that you -- that you told the Board about just a few minutes ago in your direct evidence through -- through Ms. Murphy, was because the Board is -- has ordered that the recovery of the one (1) time tax payment that has to be made by Centra as a result of Hydro becoming its parent, was going to be amortized over thirty (30) years.

MR. DARREN RAINKIE: I think there’s -- there’s two (2) essential factors, Mr. Peters, and that’s one (1) of them. The first factor is that we are no longer subject to incremental income taxes, so there are no longer incremental income taxes as a result of an expansion project.

The second factor is that -- you know, between the time that we became non-taxable and the time that we cleared up the -- the issues related to the recovery of the one (1) time tax payment, sorry -- we -- we’ve cleaned that up now, and I think we -- we’ve resolved the issues related to Income Tax, so it’s now time to remove that from the feasibility test.

We -- I don’t think we wanted to remove Income Taxes whiles those issues were still outstanding.

MR. BOB PETERS: Will -- if your Application is granted on this point, Mr. Rainkie, will that result in the Corporation having to make refunds to certain customers that have expanded during this current calendar year?

MR. DARREN RAINKIE: Yes, I think we'll have to go back through the main extensions and make that adjustment.

MR. BOB PETERS: Does that answer you've given me, Mr. Rainkie, imply that you have done main extension expansion since January the 1st of '04?

MR. DARREN RAINKIE: I'm not sure how much -- how many there would be after January 1st; that's something I don't have off the top of my head. I guess I could -- I could probably find that out.

MR. BOB PETERS: Is that a matter, Mr. Rainkie, that your second panel can help you with?

MR. DARREN RAINKIE: No.

MR. BOB PETERS: All right. Well then I'll -- I'll ask you to -- to check on that and advise the Board as to whether there have been feasibility tests run on new expansions, whether it's for main extensions or other franchise areas. You can let us know?

--- UNDERTAKING NO. 1: Advise the Board as to whether there have been feasibility tests run on new expansions, whether it's for main

extensions or other franchise areas.
(Answered on Page 128)

MR. DARREN RAINKIE: I can do that, Mr. Peters. I can indicate that if there would have been feasibility tests ran for expansions and new franchise areas, they would have been filed with the Board, so I can probably give you a 99.9 percent assurance that there haven't been any projects that have been completed, but -- but I'll check and get the numbers for the main extensions.

MR. BOB PETERS: All right. Mr. Rainkie, in terms of additional approvals that I see in your Application that you're asking for, I just want to make sure again we've got them on the record; you want Interim Order 69/04 approved on a final basis, and that was the order that addressed the primary gas rate-setting methodology process, effective May the 1st of 2004?

MR. DARREN RAINKIE: Right. It set -- it did two (2) things, it set primary gas rates on May 1st, 2004, and it discontinued the requirement for a Public Notice of those Primary Gas Rate Applications.

MR. BOB PETERS: And it also had a requirement that you would notify your customers by way of bill insert or other similar mechanism, post-rate adjustment?

MR. DARREN RAINKIE: That's correct, by both press release and bill insert.

MR. BOB PETERS: And again, you’re finding -- by seeking final approval of that order, Mr. Rainkie, do -- can the Board interpret that as the Corporation is satisfied with the way that that process is working?

MR. DARREN RAINKIE: Yes, we’ve -- we’ve only tried it once, but we haven’t got any negative feedback and I think it was contemplated when, way back in Order 55/00, when we started this process out, that we would try it with the public notice for a while, and once customers became aware of the process, we might be able to discontinue that.

So it’s -- it -- it worked satisfactorily on -- on August 1st, and I think it will save us probably in the order of a hundred and twenty thousand dollars ($120,000) a year in terms of notice costs.

MR. BOB PETERS: In terms of another interim order, Mr. Rainkie, Order 100/04, was I believe the Interim Order that set the primary gas rates effective August 1st of this year; do you recall that?

MR. DARREN RAINKIE: I certainly do.

MR. BOB PETERS: And, in that one as well, the Board ordered that the rate riders that were on supplemental gas, transportation and distribution to Centra would be removed?

MR. DARREN RAINKIE: That’s correct. That was, of course, the Board's direction from Orders 118/03 and 125/03 last year, that those rate riders would expire on July 31st, 2004.

MR. BOB PETERS: And when the rate riders expire, Mr. Rainkie, the Corporation reverts back to base rates; would that be correct?

MR. DARREN RAINKIE: Yes, this is about the only time in history that I can remember our billed schedule being equal to our base schedules -- base rate schedule.

MR. BOB PETERS: And that's shorthand for saying that there were no rate riders that were in addition to, or in reduction of, base rates that this Board has approved?

MR. DARREN RAINKIE: That's correct. That was even the case for the primary gas rate rider; the amount was so small that it didn't register on the screen when we went to calculate our rate rider.

MR. BOB PETERS: Mr. Rainkie, Interim Order 16/04 and 45/04 were Orders issued by this Board dealing with the high volume firm and setting of demand; can those orders be finalized as a result of this process in the Corporation's view?

MR. DARREN RAINKIE: I sure hope so, Mr. Peters. I think we need to get resolution of these -- this issue, both for the customers' sake and for the Company's sake, that we know how we're -- we're billing these demand costs.

I don't recall those Orders being issued on an interim basis, so I'm not sure. Procedurally, we have to confirm them as final, but -- but certainly we filed evidence in -- in this Proceeding, and our Proposal in this Proceeding, if approved by the Board, would put that issue to rest.

MR. BOB PETERS: We'll come to that, I suppose that's another issue for the Second Panel, Mr. Rainkie, and I know there are interested parties who will canvass that, in addition to the Board.

Mr. Rainkie, before I leave Order 100/04, I think I had understood Mr. Sanderson giving advice to the Board that the primary rates that were set by his Board on August the 1st of 2004, were forecast and included forecast price management impacts?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: And because, I think the price management impacts for the months of October of '04 were not settled, again as I recall Mr. Sanderson's evidence of a few minutes ago?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: Mr. Rainkie, recognizing those costs have not been finalized, is it the Corporation's view that Interim Order 100/04 can be approved on a final basis, or is that a matter that's going to have to stand over until those issues are finalized?

MR. DARREN RAINKIE: I'm not sure it's 100 percent clear; this is where we get into some of the procedural aspects, I guess, of the Public Utilities Board.

To me the only thing missing for -- recognizing that we have purchased gas variance accounts that take the differences between actual and forecast gas costs, so regardless whether -- whether the Board finalizes this or not they're going to see in the next cost of gas year and the next year rate, all the final balances coming out of the -- of the -- of the derivative hedging transactions and will get to approve them or disapprove them as they see fit.

So I don't -- it doesn't mean if you finally approve that order that it's never looked at again by the Board. But my understanding of the Board's procedures is that when orders are issued on an interim basis, they're suppose to try to confirm them as final at the earliest opportunity.

And I think that's what our proposal is based on is that it's, you know, the only thing that was missing in approving the rates was -- was a public hearing. We're now at a public hearing, it's probably acceptive -- acceptable procedurally to close that order off as final and the results of the derivative hedging transactions for 2004/05 will be subsequently reviewed next year by the Board.

I guess the Board could go the other way and say, well if -- if -- all of the gas costs in that order aren't final, we won't finalize this order. And I guess next year at this time or whenever we have the next major hearing I'll be back asking for approval of that order.

I'm not sure that anything, once again, really hangs on it but it's -- I think the only thing missing in the approval of that order on a final basis was a public hearing. We have a public hearing now to look at it and we could finalize it procedurally if we want to.

MR. BOB PETERS: All right, Mr. Rainkie, just to cover off on your answer, you've indicated to the Board that the results of the -- of the financial derivative hedging program will flow into the PGVA account and will be there to be examined by the Board at a later date as well.

MR. DARREN RAINKIE: That's right, Mr. Peters. Inherently, any increase or decrease to gas costs because of derivative hedging transactions -- our gas costs and all gas costs eventually flow into a purchase gas variance account.

MR. BOB PETERS: And the hypothetical I'll throw to you then, Mr. Rainkie, is if for any reason the Board -- well let's start off that the Board does approve on a final basis Order 100/04 as you've requested and at a later point in time the Board disallows some of the gas costs, say related to the hedging program, the Corporation's view is that could be addressed in a subsequent order and taken into account when the PGVA is calculated the next time?

MR. DARREN RAINKIE: That's right. At the next major hearing we'll have, we will present our deferral accounts for 2004/05 which would include the hedging impacts and so they could be adjusted next year.

MR. BOB PETERS: Thank you, Mr. Rainkie. One of the interim orders that you also sought approval for, sir, was the additional pressure zone that now exists in the Centra service territory. Can you briefly explain that to the Board?

MR. DARREN RAINKIE: Earlier this year we acquired the Gladstone Austin Natural Gas Co-op and there is a I guess a federal -- federal regulations in terms of the measurement of -- of gas and I think Mr. Barnlund can go into this if you need another level of detail. I'm kind of the fifth wheel witness here that's covering off everything that nobody else is covering I guess.

But -- but my understanding of that is that based on differences in elevation there's a difference in atmospheric pressure. There's a -- with each increment there's a different fix factor that is put into the billing system to account for those differences in pressure. When we went into the Gladstone Austin area we found twenty (20) customers that weren't in -- in our current pressure zones.

We had, I guess, from the old Plains Western days and the ICG days and the -- and the Greater Winnipeg days, we had all of the pressure zones covered off except one in the middle. So we plugged that hole with this Application in order that we can conform with that -- the applicable regulations.

MR. BOB PETERS: All right. Thank you, Mr. Rainkie. Mr. Rainkie, in tab 2 of the Book of Documents and, Mr. Chairman, and Board Members, you provided a level of update, Mr. Rainkie and that was generally filed on, we'll call it just yellow paper, correct?

MR. DARREN RAINKIE: You disappoint me, Mr. Peters. I thought you were going to have another name -- more specific name for this, but yeah, I recognize it as yellow.

MR. BOB PETERS: All right. Well let's keep with -- with that, Mr. Rainkie. In reading the updated materials from August 9, sir, that was the first time you've told the Board, other than the interrogatories, that you wanted the rates to become effective on November 1, 2004, correct?

MR. DARREN RAINKIE: That's correct. We

originally filed the application in late February and we -- we thought we might be able to sink this one in for August 1 implementation but it became apparent with the Board schedule and -- and the requirement for electric GRA that November 1st was probably a better implementation date for everybody.

MR. BOB PETERS: And is it the Corporation's practise to ask this Board to leave those rates open-ended, or is there a sunset date put on when these rates would expire?

MR. DARREN RAINKIE: Sorry, Mr. Peters, I'm not clear, when which rates would expire?

MR. BOB PETERS: Okay, that's a good point, Mr. Rainkie. On November 1st, 2004, if your Application is granted, you will have new non-primary gas rates in place; correct?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: And those rates will include both a base rate, as well as a billed rate, and the billed rate would be equal to the base rate plus a rate rider?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: At what, and you've told the Board that you want the rate rider to fall off in about nine (9) months, on July 31st of '05; is that correct?

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: When should the base rate expire?

MR. DARREN RAINKIE: I don't think -- base rates expire, I think they continue until there's a further Order of the Board, recognizing, once again, that we have PGVA accounts that take all the swings between actual gas costs and forecast gas costs. I mean, there has to be a rate to charge, so until a further Application of the Board -- of Centra, we wouldn't change the base rates.

MR. BOB PETERS: I appreciate that answer, Mr. Rainkie. But would the Board be correct in assuming that Mr. Sanderson has forecast twelve (12) months of gas costs. And you're going to recover those gas costs in the ensuing twelve (12) months through the base rates, for supplemental gas transportation and the UFG component of distribution?

MR. DARREN RAINKIE: Well, Mr. Peters, I think -- I think we may be getting more into the area of non-gas costs when we get worried about the test period versus the -- the period that the rates are going to be in effect.

I mean, we -- we obviously want annualized base rates, so we forecast twelve (12) months worth of gas costs, we don't forecast, even if we're asking for the rate riders to come off in nine (9) months, we don't forecast nine (9) months for the gas costs, because the rates wouldn't be reflective of what we expect the underlying costs to be.

So, I know we're a little bit out of step because of the lateness of this adjustment this year, but I think we can live with that, and we won't be as far out of step next year, I think, just because of the timing of this Hearing.

But I -- I don't see anything wrong with using the 04/05 gas costs as a proxy for the base rates. And when we come back next time, we'll be using our 05/06 gas costs forecast as the -- as the forecast that's built into the base rates at that point in time.

MR. BOB PETERS: Thank you for that answer, Mr. Rainkie. Perhaps I could have phrased the question: What volumes is the Corporation putting before this Board in order to calculate the unit rates going forward?

MR. DARREN RAINKIE: It's the fiscal 04/05 volumetric calculations.

MR. BOB PETERS: And so you've based it on the -- the twelve (12) month fiscal year forecast?

MR. DARREN RAINKIE: That's correct, because internally, we do our forecasts on the fiscal year, and that's the, you know, the approved, recognized volume that's used internally for all these types of calculations.

MR. BOB PETERS: And so your previous answers to me, Mr. Rainkie, when you were talking about a mismatch, what you were really saying is that you've got twelve (12) months forecast before the Board, it may not line up month for month for which the rates will apply, but you still feel it's an appropriate proxy for the costs going forward?

MR. DARREN RAINKIE: I think that it's still appropriate, yes, Mr. Peters.

MR. BOB PETERS: In your update material, you tell the Board that you have recalculated the costs included in your Application, based on a forward price strip as at July 2nd, 2004; can you explain to the Board why you have updated your filing?

MR. DARREN RAINKIE: Well, because we -- we purchase gas on an index, that index changes every day, and it's been the past practise that we will update the Application to have more current information, because of the time that it takes for the process to work itself through the filing of an -- or I'll go even earlier there, the development of the Application, the writing of the materials, the putting together of the schedules, the process.

We have to have a starting point and we have to have a certain gas cost when we file, and of course, the practise has been to update it sometime during the process, closer to the Hearing, so that it's more reflective of -- of current forecasts of gas costs on a go-forward basis.

MR. BOB PETERS: And when you use a forward price strip, would the Board be familiar with this methodology in terms of the setting of the quarterly primary gas rates?

MR. DARREN RAINKIE: That’s correct. In fact, I think we used the same strip that we used in the August 1st, 2004 Primary Gas Application.

MR. BOB PETERS: Mr. Rainkie, in your update materials, you also tell the Board that you’ve updated the TCPL tolls as well as the Great Lakes Gas Transmission tolls, and also made adjustments on account of Canada-US exchange rates and also the supply contracts with Nexen for 04/05.

MR. BRENT SANDERSON: I can take that, Mr. Peters, that’s correct.

MR. BOB PETERS: And this comes by way of -- some of these amendments, Mr. Sanderson, are the August 25 letter and attachments which contain the agreements that the company has negotiated with respect to future gas costs.

MR. BRENT SANDERSON: That’s correct.

MR. BOB PETERS: And in terms of what you’re asking of this Board is you want the Board to approve your forecast gas costs for 04/05 based on the contracts that you have for those periods of time.

MR. BRENT SANDERSON: That’s correct.

MR. BOB PETERS: Can you just tell the Board and I’ll, perhaps, cover it a bit further later with maybe Mr. Stephens, but does the Canada-US exchange rate -- that’s been revised in your updated filing, I take it.

MR. BRENT SANDERSON: That's correct.
MR. BOB PETERS: Can you indicate to the Board what -- what was the nature of that revision, Mr. Sanderson?
MR. BRENT SANDERSON: If you just bear with me one (1) moment while I find my reference, please.
THE CHAIRPERSON: We'll take advantage of that for a two (2) minute break.

--- Upon breaking at 11:17 a.m.
--- Upon resuming at 11:22 a.m.

THE CHAIRPERSON: Okay, Mr. Peters.
MR. BOB PETERS: I'm able to --
THE CHAIRPERSON: I apologize, there's Mr. Warden, too.

CONTINUED BY MR. BOB PETERS:
MR. BOB PETERS: Mr. Sanderson, can you provide the Board with the information about the exchange information.
MR. BRENT SANDERSON: Yes, I can, Mr. Peters. The original application reflected a forecast Canada-US exchange rate of approximately a dollar thirty-seven ($1.37). The update filed in August with the Board reflected an

updated forecast of Canada-US exchange of a dollar thirty-one ($1.31).

MR. BOB PETERS: And just to talk about this on a bit higher level, Mr. Sanderson, many of your purchases and expenditures are in US funds because of the US transportation and gas supply, correct?

MR. BRENT SANDERSON: That is correct.

MR. BOB PETERS: And the major expense is the ANR storage arrangement.

MR. BRENT SANDERSON: That is correct.

MR. BOB PETERS: And I believe in the -- and I don't want to get down to too many small details here, but in the PUB-I-IR-27 you explained to the Board that you were using a higher exchange range of about a dollar fifty ($1.50) or a dollar fifty-three ($1.53) previously when you forecast gas costs for 2003/04. But what the actual has come in at is -- is closer to a dollar thirty-seven ($1.37) as you've just told us and forecast going forward it's now a dollar thirty-one ($1.31), I believe.

MR. BRENT SANDERSON: Off the top of my head I can't speak to what the actual average Canada-US exchange rate was in 2003/2004. The two (2) figures that you just referenced, the dollar fifty ($1.50) and change that you referenced was what's embedded in the currently approved base rates and the dollar thirty-seven ($1.37) was the forecast reflected in our initial 04/05 Application.

MR. BOB PETERS: Can you explain to the Board what happens when you embed, say a dollar fifty ($1.50) for exchange, and it comes out to be more like a dollar thirty-seven ($1.37), what happens when you -- when your forecast wasn't matching what the actual is?

MR. BRENT SANDERSON: All things being equal, we would recover costs from the customers that are in excess of our underlying cost to -- to a certain extent. And that excess will build up as a credit balance owing to customers in the appropriate PGVA accounts.

MR. BOB PETERS: And as part of this Application, there is a refund to consumers based on the -- the difference in exchange rates?

MR. BRENT SANDERSON: Yes, that exchange rate difference makes up part of the approximately $16.5 million that we're proposing to return to customers in rate riders effective November 1st, '04

MR. BOB PETERS: Mr. Rainkie, back to you sir, in terms of your update, you tell the Board that you've also updated the volumes in your Application for the special contract customer class.

Do you recall that?

MR. DARREN RAINKIE: That's right.

MR. BOB PETERS: Can you tell the Board why that volume update was done for that customer class?

MR. BRENT SANDERSON: I may be able to speak to that, Mr. Peters. At the time of the preparation of the original 04/05 forecast, there was some question as to what the production levels would be with regards to the special contract customers operations during fiscal 04/05, to such an extent that there was some question whether they would even continue in business in Manitoba.

So at that point we were forced to develop a forecast for the customer and the possible range of volume takes that they were looking at ranged anywhere from zero to -- to normal annual levels. And they were unable to provide any -- any clearer direction on what they expected their operations would look like in the 04/05 fiscal period.

So as a result we were -- we chose a middle ground scenario where we forecast their volumes at half of normal production levels. As the actual 04/05 period progressed, their operations or their future in Manitoba became clearer and they were able to provide us with some clear indication on what their expected production levels would be.

And they were significantly higher than what was reflected in the original 04/05 forecast and so those higher volume levels are reflected in the update filed with the Board in August.

MR. BOB PETERS: Thank you for that, Mr. Sanderson. In terms of the updating of the unaccounted-for gas percentage in your -- in terms of total through-put, the unaccounted for gas is now proposed to be .9 percent of total through-put?

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: And the other update that the Board has from you was the market to market impacts of your derivative hedging program for 03/04 as well as 04/05 and that was because a -- a new forward price strip was used and also because some of those derivatives matured and crystallized?

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: So just to bring all of this into a focus in terms of dollars and cents, the Board is being told that the rates that are in place right now for non-primary gas costs are approximately $3.2 million too high on an annual basis?

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: And therefore the new rates that you're asking this Board to approve will result in revenues to the Corporation that are $3.2 million lower from those base rates?

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: And the other bit of good news, Mr. Sanderson, is that the deferral account balances to March 31st, ’04 have been calculated for the fiscal year of 2003 and 2004 together with carrying costs to October 31. And you’re telling the Board that there now is $16.5 million that will be available to be refunded to the various customer classes?

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: And that $16.5 million is an increase from the fourteen point five (14.5) that was set out in the initial Application?

MR. BRENT SANDERSON: That’s correct. That amount -- a greater amount owing to the customers.

MR. BOB PETERS: And again, it’s the $3.2 million rate reduction in base rates would take place over a twelve (12) month period and the refund of $16.5 million would take place over a nine (9) month period, if I’ve understood your Application?

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: Some final matters to just check off for the record, Mr. Sanderson and Mr. Rainkie, that the update also made some minor, I’ll call them minor corrections to the Cost Allocation Study. And we’ve already talked about the volumes, but also with the power station, bill rate, the basic monthly charge, and the interruptible class, and I appreciate that’s a matter for the Second Panel, but that was part of the update as well?

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

MR. BOB PETERS: And while you have told the Board, Mr. Sanderson, that the volume for the special contract customer was increased based on what the Corporation feels is the appropriate volume for fiscal 04/05, that also had a -- an affect on the unit cost for the unaccounted-for gas, because you had more volumes than you had planned initially?

MR. BRENT SANDERSON: I might be able to answer half of your question and the other half I might have to defer to Ms. Derksen; increasing the special contract customer's forecast volumes would increase the absolute amount of our forecast unaccounted-for gas over the forecast period.

Whether that would affect the unit value of the rate itself, I think there's a bit of -- some question as to whether it would increase absolute costs. But recovered over a greater amount of volume, I would suspect that all things being equal, that it would have little affect on the unit value of the UFG distribution rate.

MR. BOB PETERS: I might not hold you to that last answer, because I think Ms. Derksen can maybe provide us with some more information on it, particularly to that customer, but the dollar amount of UFG doesn’t change, it’s rather the unit cost to that particular customer class that would change, or is that not your understanding?

MR. BRENT SANDERSON: As it affects the special contract customers’ rate, I think it would be better that we leave that question for Ms. Derksen.

MR. BOB PETERS: Thank you, Mr. Sanderson.

The last point I want to remind the Board of, in terms of what’s being asked of them, is that in terms of supplemental gas PGVA, Mr. Sanderson, a large portion of that $16.5 million that has been over-collected, comes out of the supplemental gas PGVA account as I read your filing; am I correct?

MR. BRENT SANDERSON: That’s correct. Approximately $11.1 million.

MR. BOB PETERS: And this Application would normally come into refund at the various PGVA accounts by virtue of the type of gas charge that created them. And what I’m saying is, if you had a transportation surplus, you’d have a transportation PGVA to refund some money, and that’s generally how it would -- would be calculated; correct?

MR. BRENT SANDERSON: To state it a little more clearly, if, in your example, using transportation, if it was a transportation PGVA account which gave rise to a balance owing to the customers, we would normally calculate a transportation rate rider to tack on to the transportation, base rate to either refund or recover that cost, yes.

MR. BOB PETERS: All right. And, Mr. Sanderson, but using your example, supplemental gas was over a million dollars -- has over a million dollars in the PGVA related to supplemental gas to be refunded. But in this Application, you're not asking the Board to approve a supplemental gas rate rider. You're proposing that for most customer classes, their share of that $11 million get refunded by way of a rate rider that is done through the distribution charge?

MR. DARREN RAINKIE: That's correct, with the exception of a little bit of a different treatment for the main-line class, because it would otherwise create a negative billed rate.

MR. BOB PETERS: And for the main-line class, Mr. Rainkie, as I understand the Application, you want a separate billing line on the invoice to the customer, rather than doing it through a supplemental gas rate that will contain what you called a negative rate?

MR. DARREN RAINKIE: That's correct. I think there's four (4) or seven (7) customers that -- because of the -- the other proposal worked for our two hundred and fifty thousand (250,000) customers, we've -- had a slightly different proposal for the four (4) or seven (7) customers that are in that class. But it has the same effect, just a different treatment.

MR. BOB PETERS: The same affect is that you're refunding the money to the appropriate customers in the class, it's just how you're labelling that is going to be different?

MR. DARREN RAINKIE: That's right. It's because those customers are billed off of a separate billing system, we can make those kind of adjustments quite easily.

MR. BOB PETERS: And finally, the customer impacts that I said in my opening comments, a typical residential consumer's annual bill will decrease by approximately 3.9 percent or fifty-two dollars ($52) on an annual basis compared to your August 1st rates, is that correct?

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

MR. BOB PETERS: And that reduction, Mr. Rainkie, of 3.9 percent or fifty-two dollars ($52), that incorporates both the reduced base rates for the non-primary gas as well as the refund of the PGVA and gas cost deferral accounts?

MR. DARREN RAINKIE: That's correct. It's a comparison of billed rates versus billed rates.

MR. BOB PETERS: All right. Thank you. I

would like to turn with the Panel to Tab Number 3 of the Book of Documents that's been prepared and perhaps for the benefit of myself and the Board, run through the -- the gas dispatch rules. Mr. Stephens, is that an area that is near and dear to your heart?

MR. HOWARD STEPHENS: Apparently so, sir.

MR. BOB PETERS: Well then let's talk about that. Would it be correct, Mr. Stephens, to tell the Board that the gas dispatch rules have not changed from 2003/04 when you were last before the Board?

MR. HOWARD STEPHENS: No, our dispatch rules are precisely the same as they were at that time. There isn't a lot of flexibility associated with them but the -- the general concept is still the same.

MR. BOB PETERS: All right. And when we talk about dispatch rules, Mr. Stephens, we're talking about how Centra manages its daily load, is that correct?

MR. HOWARD STEPHENS: Yeah. It's the order in which we bring on supply, transportation and storage to provide the lowest possible cost of gas for the consumer each and every day.

MR. BOB PETERS: And in -- in Tab 3 of the Book of Documents that I've circulated, I have reproduced three (3) attachments that came from Tab 3 of Centra's filing and they're in colour. Could you briefly take the Board through the summer operations of the utility using the Attachment 1 in Tab 3, Mr. Stephens.

MR. HOWARD STEPHENS: Certainly. I'm a little bit rusty at this. I haven't had to do it for a while so bear with me.

MR. BOB PETERS: Yeah.

MR. HOWARD STEPHENS: And if I get stuck in the jargon, please stop me if I'm using jargon you don't understand what I'm talking about. We have three (3) major components in terms of transportation capacity, one (1) being Trans Canada capacity which is identified as the pink line.

Great Lakes capacity which is the yellow line, or gold line if you will, and ANR capacity which would be the green line. And during the summer months which summer operations which encompasses the months of April through October and to the extent that the Manitoba market requirement is at or less than our Trans Canada FS NDQ. You'll see the number, it's two hundred and four thousand seven hundred and eighty-four (4,784) which has not been updated but it -- we'll call it two hundred thousand (200,000) GJ's per day --

MR. BOB PETERS: Just to interrupt you, Mr. Stephens, if I might. When you're talking about FS, you're talking about --

MR. HOWARD STEPHENS: That's firm service.

MR. BOB PETERS: -- firm service on TCPL?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And that firm service is a cost that you incur whether you use it or not?

MR. HOWARD STEPHENS: Well, it is -- it is -- it's a two (2) component rate heavily weighted towards the reservation charge but there is also a commodity charge associated with it.

So we are entitled to take each and everyday up to -- roughly two hundred thousand (200,000) in Gigajoules per day. During the course of the summer months we have a considerable amount of excess capacity. The Manitoba load would be on the order of forty (40) to fifty thousand (50,000) Gigajoules. We have an additional fifty thousand (50,000) that we would be sending to storage down -- via Great Lakes to refill storage subsequent of the previous winter.

And the -- and the path that it would follow, I mean, is very self explanatory and this is the blue area -- blue arrows. We take the TCPL down from Winnipeg to Emerson, down Great Lakes to Crystal Falls down ANR, go around the lake and then put our gas into storage. And to the extent that that assumes that -- that is a normal year's consumption which would be -- which would deplete our storage in the order of 10 to 11 million Gigajoules out of the 15 1/2 million Gigajoule capacity that we have; that capacity will allow us to fill storage.

In a year that's colder than that where our -- our inventory storage would be depleted by more than that, we would then bring on the ANR southwest which is the -- it's called ANR pipeline FTS 7860 Gigajoules. And there's a few -- Oklahoma supply -- supplies that. We would bring that on next as the next component to help us refill storage.

And in a maximum year's circumstance we will also have access to ANR southeast capacity that allows us to bring gas up from Louisiana of 21,202 decatherms or 22,380 Gigajoules and that is used either in whole or in part to top up the remaining storage to the extent that it's necessary.

MR. BOB PETERS: And again just to interrupt you if I may, Mr. Stephens, the gas that's coming from Western Canada into storage, the Corporation considers that primary gas.

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: Even though it's going into storage it's considered primary gas because it's from Western Canada.

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: But if you're getting gas from Oklahoma and/or Louisiana that is considered supplemental gas.

MR. HOWARD STEPHENS: All other points -- we could but -- the other wrinkle to this is we could buy delivered service at some point along the pipeline and have it delivered to storage and that would also be considered supplemental.

MR. BOB PETERS: And would I also be correct, and Mr. Sanderson may want to help us here, that -- he's told the Board that the last time you forecast supplemental gas cost to this Board you were out by about $11 million and that has now ended up in the PGVA account because it's been collected from customers already and now is going to be refunded but that $11 million is attributable to the Corporation having to decide and figure out how much gas it gets into its storage arrangements from the primarily Oklahoma and Louisiana supply?

MR. HOWARD STEPHENS: Yes, when we go to develop our storage plant at the beginning of the storage refill season, we look at the relative cost of delivered service versus -- well first of all, what our inventory is going to be to the extent that our TransCanada capacity and relays capacity will provide for a complete refill; then we will -- will not have to use ANR southwest so there is an automatic credit associated with that -- that capacity because we're not utilizing it even though it is accounted for within Mr. Sanderson's model or the budget as a normal year requirement. So you're going to have an immediate credit associated with that.

Then to the extent -- I mean the other example would be if we can find delivered service that would be a lower cost than the ANR southwest, we would take advantage of the lower cost delivered service into storage and that would also result in a credit.

So we always -- it's not -- and that's why I opened up the discussion. It's not -- we're not married to the rules. There's a certain amount of flexibility associated with that so that we ensure that we have the lowest potential cost -- or we're acquiring the gas at the lowest potential costs --

MR. BOB PETERS: And if I --

MR. HOWARD STEPHENS: -- through --

MR. BOB PETERS: -- if I can in my language, Mr. Stephens, just clarify for the Board, what you mean by delivered service is that, you're telling the Board you have contractual arrangements as mapped out here on the -- on the various -- on the map for summer operations but there may be occasions that arise during the year where you can -- you can acquire gas from a vendor cheaper than what you may have arrangements in place for by way of your contracts.

MR. HOWARD STEPHENS: Yes. Delivered service, very simply put -- a simple example would be -- a third party has excess transportation and commodity and is prepared to deliver it to the Manitoba delivery area but the total cost associated with that gas on a unit basis is less than the commodity cost for the southwest or the Oklahoma supply.

And in that circumstance I'm in a better position to take delivery of that delivered service at a lower cost and let the southwest sit empty or try to broker the -- that capacity off. I hope I answered your question.

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

MR. HOWARD STEPHENS: I should point out the one (1) -- one (1) component I did neglect to mention is that during the summer operations -- we are talking about the periods of April through October and for the months May through September with the exception of this year perhaps -- the weather is generally fairly warm so we're using -- we have more than enough TransCanada Pipeline capacity.

The months of April through October, which we refer to as the shoulder months, we can experience very cold weather. We don't have access to our storage during the course of those months and -- those being the refill months, and there are circumstances -- in those circumstances we are very much in the mode of looking for delivered service and purchasing delivered services to satisfy the market requirements.

MR. BOB PETERS: Mr. Stephens, when you talk about putting gas into storage, and your map goes around the south end of Lake Michigan into ANR storage area, can you just describe to the Board, what is that -- physically, what is that storage area, or how do you store that?

(BRIEF PAUSE)

MR. HOWARD STEPHENS: Sorry, Mr. Peters, you need to run that by me one more time.

MR. BOB PETERS: Well, I was going to have you paint the picture for the Board in terms of what is the storage area that you talk about up in northern Michigan? Is it above ground, below ground, is it -- what is the storage?

MR. HOWARD STEPHENS: It's reservoir storage, it's depleted gas wells in some cases, natural formations, very similar to what occurs in Ontario, only there are many more of them. You can't point to any particular field and say that that's Centra Gas's field, and that Centra Gas has gases in there.

We deliver it to a notional point on the ANR system, and from there it disappears into their system, and all I'm concerned about is when I nominate to get it back that materializes back off their system and into the pipes.

MR. BOB PETERS: Mr. Stephens, if we turn the page to your Attachment Number 2, also found in Tab 3 of the Book of Documents handed out, there's a Winter Operations, and that would be for November 1st through March 31st of a given year?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And in this situation, you've told the Board that in the summer months you have surplus capacity on TCPL; what happens here in the winter months?

MR. HOWARD STEPHENS: Well, for the most part during the course, unless it's an exceptional year, and there are always exceptions to every rule -- we -- again, the dispatch role would be that we will use the TCPL capacity to the full extent possible, until such time as the Manitoba load exceeds that capacity.

Once we exceed that capacity, then we will look at the relative costs of ANR southwest versus our inventory cost for storage, and also looking at the -- having regard for the weather forecast, and we will make a determination as to whether or not we're going to start to bring the ANR southwest on, or just pull from storage and defer the decision in terms of pulling gas from the ANR lake until later into the winter season.

So, for the -- the majority of the winter, unless it's a very warm winter, we are running, I mean, the

TransCanada capacity full out; it’s -- it’s running at 100 percent capacity, except for, I think the threshold is an average daily temperature of zero degrees Celsius.

We’d take the gas from Empress, deliver it to the Emerson delivery point on Great Lakes -- excuse me, I’ll back up. We take the gas to Winnipeg in the Manitoba delivery area, as well as the Saskatchewan delivery area, then anything in excess of that that we pull from storage, is done on a back haul arrangement, where -- which is really a misnomer or a little bit misleading insofar as the gas does not physically back haul, or get back hauled or turned around, it’s -- it’s an arrangement where we take the gas by displacement, we take gas that would ordinarily end up being withdrawn in our storage area; we intercept that gas, making more capacity available in the Great Lakes system, and then putting gas onto the Great Lakes system, further downstream at the ANR storage interconnect.

So, from that perspective, we’re -- there is some benefit associated with that arrangement from the pipeline’s perspective, because we’re making more capacity available.

MR. BOB PETERS: So, Mr. Stephens, just a couple of points on what you’ve told the Board: First of all, you’ve told the Board that you get most of your gas delivered into the Manitoba delivery zone; that’s a term used by TCPL, the Manitoba delivery zone?

MR. HOWARD STEPHENS: Manitoba delivery area, yes.

MR. BOB PETERS: All right. And then you also said you get some gas delivered into the Saskatchewan delivery area, correct?

MR. HOWARD STEPHENS: We have a small component. It is about 3,800 GJ's per day of capacity that serves the Minell line which goes up to Serveduff (phonetic).

MR. BOB PETERS: All right. So the -- the -- the Saskatchewan delivery zone provides gas that comes off the TCPL pipeline in Saskatchewan, near the Manitoba border and runs up to serve Robin/Russell/Dauphin area?

MR. HOWARD STEPHENS: Yes, and we put that inter-connect in on the Saskatchewan side of the border because the toll was less to haul the gas from Alberta to Saskatchewan than it was to haul it from Alberta to Manitoba.

MR. BOB PETERS: And when you tell the Board that you forward haul from Alberta to Winnipeg in the winter and you use all of your space on TCPL, that would be all of the space that's available and contracted by Centra for its firm base load service?

MR. HOWARD STEPHENS: You're mixing terms, Mr. Peters, it's --

MR. BOB PETERS: Well, for its firm

transportation to -- to have the -- the amount of gas from Nexen that's available on a firm basis would be -- would be delivered through TCPL?

MR. HOWARD STEPHENS: The amount of gas -- the gas we buy from Nexen as well as the broker gas that we move into the WTS arrangement.

MR. BOB PETERS: And the amount of gas you buy from your supplier, whether it's firm gas or swing service gas comes through on the TCPL?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And when you talk about back haul, it's -- it's a notional concept where the molecules don't -- don't come the way your red arrows show on the map, but it's a notional understanding that that's how the gas would get back to Winnipeg conceptually, even though they don't physically flow that way?

MR. HOWARD STEPHENS: For the most part. We'll get into that a little bit more detail with respect to that a little bit later, I think.

MR. BOB PETERS: All right. And what -- what happens for the most part is that when the TCPL pipeline is -- your share of it -- you're taking 100 percent of what you're entitled to and you need more gas than what you have under contract, you then have to make arrangements where you will release gas out of your storage area to a customer in return for their giving you gas in the Manitoba delivery area?

MR. HOWARD STEPHENS: And we don’t know who the customer is. We make the nominations directly to ANR and Spirit Lakes and they -- they have underlying arrangements that’ll allow for that to occur.

MR. BOB PETERS: All right. And even though the molecules don’t move in the back haul direction, there are tolls that apply to those back haul arrangements?

MR. HOWARD STEPHENS: That’s correct. I guess the one (1) addition I could put to that is that we also have the access to the NR South-West during the course of the winter months and, if necessary and the winter is sufficiently cold, we will bring that on line and help us serve up our peak day requirements or peak winter requirements.

MR. BOB PETERS: And so what you’re telling the Board there is that the molecules do actually flow in that time back to the Manitoba delivery zone?

MR. HOWARD STEPHENS: No, the ANR southwest would flow up to Crystal Falls which is on the orange line, then it -- that -- that gas in turn would -- would in turn be back hauled as well.

MR. BOB PETERS: All right, thank you. The next page in the -- in the Tab 3, Mr. Stephens, is a chart that is to demonstrate, I believe, to the Board what your firm day requirement might be and how you would propose to meet that in terms of your gas supply. Is that correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: Can you briefly then explain it to the Board?

MR. HOWARD STEPHENS: Certainly. The bar on the left, bar chart on the left -- well, actually the bar chart on the right shows us our peak day requirement of 493,000 Gigajoules per day.

We have an interruptible load of twenty-five point one (25.1) over and above that, Terajoules per day over and above that, but on a peak day -- peak day, unless we can buy the gas to sell to the interruptible customers, they would in -- in that circumstance be curtailed.

The bar chart on the left side of the table shows the components that we use to satisfy that daily requirement. You see in the orange, that's the Trans-Canada FT that we just talked about which was running during the course of -- I mean on that peak day will be running flat out.

We have this small piece of Oklahoma which is the seventy-eight sixty (7,860) or 7.86 Terajoules. Then we have the 208.59 Terajoules of storage withdrawal capability which all adds up to, if my memory serves correctly, is

421,000 Gigajoules per day, leaving, relative to our four hundred and ninety-three (493), about 71.77 Terajoules per day, unprecontracted, or to this point, not contracted, using, and I hate to use the term, hard assets versus soft assets, but we might as well go down that road.

We don't have capacity on TransCanada system to satisfy that extra requirement. We go to the market on those days, and -- and/or make other arrangements through capacity management arrangements, to satisfy that additional market requirement.

And, we go on at length in terms -- and I can give you a reference, in terms of the nature of that type of transaction.

MR. BOB PETERS: We'll perhaps come to that, Mr. Stephens. What you're telling the Board, in the purple peak day, is that that assumes the coldest day experience of the Corporation, generally in the middle of winter, when you require -- all your customers require gas sufficient that it meets the peak or the maximum amount the Corporation is to provide?

MR. HOWARD STEPHENS: Sorry, Mr. Peters...?

MR. BOB PETERS: The purple bar, Mr. Stephens, on the Attachment 3, represents your peak day requirement, which assumes again, that that's the coldest day experience the Corporation will have in Manitoba?

MR. HOWARD STEPHENS: That's our forecast peak day, yes.

MR. BOB PETERS: And you're telling the Board that the interruptible load that's shown here as well, would be in addition to that, but you do not have under contract, sufficient resources available or hard assets available to meet the interruptible load; is that correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And, likewise, you're telling the Board that the pink 71.77 Terajoules, is also without an underlying hard assets, and you serve to meet that by going to the market if that circumstance arises?

MR. HOWARD STEPHENS: That's correct. And if to the extent that I can get in excess of the 71.77, and serve the additional 25.1 for the interruptible at a price that they're prepared to pay, then we do so, and pass those, I mean, sell the gas to them, and pass the costs straight through to them.

MR. BOB PETERS: And that's by way of an alternate service arrangement that you have with those customers?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And you basically will go to a customer and say: We're going to have to curtail you or interrupt your load, because we need it to serve our firm customers, however, we can buy it at a certain price, and if you're prepared to pay it, we'll get it here and charge you that price?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And the interruptible customers will then be responsible for any costs over and above -- or will they be responsible for all costs to bring the alternate service to them?

MR. HOWARD STEPHENS: Yes. I mean, we calculate the actual cost per Gigajoule of acquiring the gas and there is a delivery charge within our tariff, that we charge them for that component as well.

MR. BOB PETERS: And, at the risk of getting too far ahead of ourselves, Mr. Stephens, but I'll try to remember to come back to it, that pink portion shown on Attachment 3 of Tab 3, that is the, you've told me that is the uncontracted, there's no firm underlying contracts to support that delivery; correct?

MR. HOWARD STEPHENS: I'll characterize that as -- there's -- as non-traditional, no traditional arrangements in terms of contracted pipeline capacity or storage capacity.

MR. BOB PETERS: And that may mean every year you have to meet that in a different fashion because it may not be the same every year?

MR. HOWARD STEPHENS: That's correct.
MR. BOB PETERS: And would I also be correct in jumping ahead, that International Gas Consultants, when they did the portfolio review, which I'm going to refer to in the vernacular as the blank page analysis, when they did that blank page analysis, one of their focuses was to recommend that Centra firm up that 71.77 Terajoules as you go forward?
MR. HOWARD STEPHENS: Yes, that -- and I should give you some history with respect to that 71.77.
Although that was not the original number in 1995 when we took our Propane Peak Shaving Plant out of service, it represented about 60,000 MCF per day, which would be on the same order of magnitude that this -- that the amount in the pink -- pink area -- that the pink-shaded area represents.
We chose not to replace that with a contracted service. So, it's since that time that we've had that component of it at risk, if you will, and -- but have been able to serve that component of the load very economically over that period of time.
MR. BOB PETERS: All right. And just before the lunch break, Mr. Stephens, one other area is, you've talked to the Board about capacity management. While I have these charts in front of the Board, would I be correct that when you're planning your portfolio for a year, you will

assume it’s going to be a peak year until the weather proves otherwise to you?

MR. HOWARD STEPHENS: No. If -- if I was to do that during the course of the winter months, then I would have to assume then because we don’t have enough gas contracted to satisfy our full firm requirement in a peak year, I would have to start inter -- curtailing interruptible customers starting November 1 until I was assured that we weren’t going to incur or have the occurrence of a peak winter season.

So we -- we have, I mean, very close, I mean we’re watching this day by day, hour by hour in terms of what the weather forecast is looking -- looking like and whether or not we can keep the interruptible customers on. And it’s a value judgment that we make on a continuous basis, we do some modelling using our internal send out model in terms of how we’re going to dispatch the gas, it’s the marketplace.

But to do otherwise would result in a significant amount of curtailment. We can’t tell with any certainty until about the middle of February that you’re not going to experience a maximum year and I don’t think we’d have very many interruptible customers left if they were curtailed from November 1st to February 15th.

MR. BOB PETERS: All right, recognizing you use value judgment along the way, Mr. Stephens, you also try to sell off what you, in your value judgment, believe will be excess capacity as the year unfolds, would that be correct?

MR. HOWARD STEPHENS: Certainly to the extent that there's a market, we will sell off any of our excess pipeline capacity. We will sell off excess gas inventory out of storage assuming that the refill cost is less than the -- the refill cost is less than the sale price, buy high and sell low.

And there are other types of transactions that we engage in that are a little bit more esoteric.

MR. BOB PETERS: But those -- would those other arrangements and the capacity management arrangements be undertaken, again based on value judgement, not based on a certainty that we're not going to have the peak -- a peak year occur?

MR. HOWARD STEPHENS: Well the capacity management where we're releasing capacity, that's -- that's on a day to day basis for the most part during the summer months. We now -- I mean it's -- when we're talking about that value I was talking about. Other than the shoulder months we have -- during the months of May through September typically a load and Manitoba delivery area, our franchise area, of around fifty thousand (50,000) Gigajoules per day.

Our storage fill is around fifty thousand (50,000) Gigajoules per day. So that's a hundred thousand

(100,000) Gigajoules per day. I've got two hundred thousand (200,000) Gigajoules of Trans Canada capacity. So I've got a hundred thousand (100,000) free not doing anything. To the extent I can find a market for that, then I will sell that -- sell that capacity off. And the same applies to the American pipes as well, but the opportunities are not as prevalent.

MR. BOB PETERS: Thank you, Mr. Stephens. Mr. Chairman, and Board Members, in light of the time I would suggest this would be an appropriate time to break for the lunch recess and remind the Board that following lunch recess, we've had a request from Professor Miller to attend and make a presentation. And after that I would be prepared to continue discussing with this Panel the 2003/04 gas cost matters that they have before you.

THE CHAIRPERSON: When does Professor Miller expect to attend?

MR. BOB PETERS: 1:45 is the current estimated time of arrival.

THE CHAIRPERSON: Okay, so we'll return then at 1:45, thank you.

--- Upon recessing at 12:04 p.m.

--- Upon resuming at 1:45 p.m.

THE CHAIRPERSON: Well, Mr. Peters, it's

1:45, so I guess we might as well commence and when Ms. -- Professor Miller arrives we can switch over to his presentation.

MR. BOB PETERS: That sounds like a good idea as long as his being tardy isn't somehow attached to my performance review on this -- on this file, sir.

I would like to invite Mr. Rainkie, who took over lunch an undertaking on -- only one (1) undertaking that I've asked, and I wanted Mr. Rainkie to tell the Board how active the Company has been with their main extension plans and whether or not they have done any of that, that would be affected by this requested change in the feasibility test and wondering if Mr. Rainkie's had a chance to consider that over the lunch hour?

THE CHAIRPERSON: Mr. Saxberg, we decided to proceed until Mr. Miller arrives.

MR, KRIS SAXBERG: Thank you.

MR. HOWARD STEPHENS: Yes, Mr. Peters, I've got some information from our staff back at the office. The information I have is that seventy-three (73) main extensions have been approved to date in 2004.

That means that some of them have been installed while others are in the queue for installation. And out of those seventy-three (73) there are fifteen (15) that have customer contributions attached to them.

So if there’s already -- if there’s a customer contribution attached to it, if we take the income taxes out, it’s going to reduce that contribution and there would have to be a refund of that contribution.

If something doesn’t require a contribution and you take income taxes out, it’s just going to make it more feasible so there’s no adjustment there in terms of the customer’s perspective.

There are also twenty-eight (28) other main extensions that are in various stages of completion that haven’t been approved for installation yet. So some of those will probably pan out, some of them might not when we give a quote back to the customer in terms of what their contribution is.

So -- so we’re talking about probably what we have in the queue right now, a little over a hundred (100) and -- and of that there’s approximately fifteen (15) that may need adjustment.

MR. BOB PETERS: And when you say fifteen (15) may need adjustment, Mr. Rainkie, it would be a virtual certainty that there would be some adjustment coming because your feasibility test included an income tax component that you’re now asking the Board to order be removed.

MR. DARREN RAINKIE: That’s right, Mr. Peters.

MR. BOB PETERS: And then it becomes a question of how large of an adjustment in the -- in the customer's favour that would be.

MR. DARREN RAINKIE: That's -- that's correct. Usually the -- that won't be that large of an adjustment because if -- it depends on the level of course -- income tax depends on the level of return which depends on the level of investment and usually the income tax is not a huge portion of the feasibility test.

MR. BOB PETERS: Would it be fair to say, Mr. Rainkie, that as you sit here today, you have not accumulated those amounts and -- and you can't tell the Board approximately how much money would have to be refunded from the contributions that have been made to date by those fifteen (15) customers?

MR. DARREN RAINKIE: No, we haven't done that quantification.

MR. BOB PETERS: Thank you for that. That does complete my questions in that area, Mr. Rainkie, so I do appreciate your getting those for me.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: I would like to turn with the Panel, Mr. Chairman and Board Members to the approval of the 2003/2004 fiscal year gas costs and you've told the --

the Board that the approval being sought is on a final basis for the primary gas rates for fiscal year 2003/04, as well as the supplementary rates -- supplemental gas rates, the distribution rates and the -- and the transportation rates. Correct?

MR. DARREN RAINKIE: That's right. We're looking for approval of all of our gas costs for fiscal 2003/04.

MR. BOB PETERS: And when we talked this morning, we talked about primary gas and we even saw a map as to where it comes from. Would I be correct in assuming that primary gas is approximately 96 percent of the gas that is flowed for residential customers and other firm customers?

MR. DARREN RAINKIE: Yes, that's correct.

MR. BOB PETERS: And for interruptible customers the primary gas is a lower percentage, probably in the order of 86 percent.

MR. DARREN RAINKIE: The determination of that percentage will vary depending on whether you're talking about actual conditions as opposed to normal weather conditions. In a normal weather year primary gas would represent about 92 percent of the interruptible customer's requirements and that can vary if weather conditions are warmer or colder than normal.

MR. BOB PETERS: All right. And when the

primary gas rate is set in Manitoba, it's set on a quarterly basis, you've told us, and you appear regularly through your written filings before the Board, and am I correct that included in that primary gas rate setting on the quarterly basis is the use of derivative hedging instruments.

MR. DARREN RAINKIE: That's correct.

MR. BOB PETERS: And turning to Tab 4 of the book of documents that I've circulated there's a copy of Centra's derivative hedging policy for primary gas together with the operating principles and procedures for primary gas and Ms. Stewart, this is an area over which you have primary responsibility on this panel; am I -- am I correct?

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

MR. BOB PETERS: And can you indicate to the Board approximately how long you've been involved in the derivative hedging program for Centra gas.

MS. LORI STEWART: Yes, I became Manager of Gas Pricing and Administration in June of 2002, and my involvement with the hedging program commenced at that time.

MR. BOB PETERS: Ms. Stewart, when the Board reads through your hedging policy would it be correct to glean that the objective of the Corporation is to mitigate natural gas price volatility?

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

MR. BOB PETERS: And when we say, "mitigate volatility", would I be correct in saying to you that that would be to -- to dampen the ups and downs that would otherwise occur on the market?

MS. LORI STEWART: Yes, that's a fair characterization.

MR. BOB PETERS: And to accomplish that you would use various derivative instruments that are available in accordance with your policy. Am I correct?

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

MR. BOB PETERS: And one (1) of the ones that we'll talk about is what you have called a cashless collar this morning and that is one (1) of those derivative instruments?

MS. LORI STEWART: That's correct.

MR. BOB PETERS: And there are other instruments that are available to you but -- according to your policy -- but you choose to use cashless collars?

MS. LORI STEWART: Yes, the Corporation's preference is the instrument referred to as a cashless collar.

MR. BOB PETERS: Why is that the preference?

MS. LORI STEWART: The cashless collar is preferred because there are up front premium costs associated with the -- the cap which, in our opinion is -- is -- given that the expected payout of all three (3) instruments is identical, that is zero, that we would, if given the option of avoiding payment of -- of an upfront premium, then the cashless collar is preferable.

In addition, the band associated with the cashless collar helps us to accomplish our objective which is to mitigate volatility.

MR. BOB PETERS: In the materials that are filed, would it be correct, Ms. Stewart to -- to categorise the company's derivative hedging policy as being a mechanistic approach?

MS. LORI STEWART: That's correct. It's a mechanistic hedge implementation strategy.

MR. BOB PETERS: And can you tell the Board whether Centra has utilized any other derivatives other than cashless collars since the mechanistic approach came into being?

MS. LORI STEWART: The Corporation has not utilized an instrument other than the cashless collar.

MR. BOB PETERS: And that is since the -- since the mechanistic approach has been used as the derivative hedging policy?

MS. LORI STEWART: Yes, that's correct. Since the mechanistic strategy has been adopted.

MR. BOB PETERS: And I think prior to that, if memory serves, there -- there may have been other instruments used at various points in time. Do you recall that or are you aware of that?

MR. HOWARD STEPHENS: I recall that. Yes, there were, sir.

MR. BOB PETERS: Okay. Ms. Stewart, when we talk a mechanistic approach, does Centra have to form a market view as to what's happening on the national gas market before it commences its derivative hedging under this mechanistic approach?

MS. LORI STEWART: No. In fact, a characteristic of the mechanistic strategy is the fact that market views do not enter into one's decision making with regard to execution of the strategy.

MR. BOB PETERS: So even if you've got the best indicators indicating to you that the market's going to go in a certain direction, the approach that the Corporation currently adopts would pay no regard to that type of perspective or view of the company?

(BRIEF PAUSE)

MS. LORI STEWART: Inherent in the use of mechanistic strategy is the conclusion that the organization or the individual does not have any competitor -- competitive advantage with regard to forecasts of and opinions of forecasts of market pricing.

So, yes, inherent in the mechanistic strategy is that no judgment with regard to the -- the direction that the market will move will be employed.

MR. BOB PETERS: Would you agree if I summarized your answer to me is you're basically telling the Board that there's nothing in it for the Corporation, so you don't speculate on which way the market's going to go?

MS. LORI STEWART: I think -- I think I'm going to rephrase that for you, Mr. Peters. I wouldn't want that to reside on the record.

The rationale for the use of the mechanistic strategy is -- is not because there's nothing in it for the Corporation. The rationale for the use of the mechanistic strategy is related to an understanding and an interpretation of the risk neutral position of our consumers.

It's related to whether or not the Corporation, and in this instance, a -- an LDC should be in the business of -- of speculating for the purpose of -- of making profit and whether or not that is an appropriate activity for an LDC to be engaged in. And the conclusion that this Corporation has reached is that it's not, hence the adoption of the mechanistic strategy.

MR. BOB PETERS: I'll just continue, Mr. Chairman, with the -- try to close off part of this line of questioning. I see my colleague, Mr. -- Professor Miller in the room and we'll give him a chance at the microphone in a few minutes if that suits the Board.

Ms. Stewart, I understand our last exchange -- you're telling the Board that -- that the Corporation doesn't profit whether gas costs are higher or lower out of the commodity cost of gas, so you don't take a position on what would necessarily happen in the market place, would that be correct?

MS. LORI STEWART: The cause and effect that -- that I keep hearing you try to -- try to define, is -- is not something that I'm going to have an easy time agreeing with, Mr. Peters.

We engage in derivatives hedging activities, because there is a need, from our perspective, to manage volatility on behalf of our consumers. And the objective of our program as we've already reviewed, is to mitigate volatility versus reducing the costs of -- of primary gas that's procured for those consumers.

So, the issue of you know, the fact that gas costs are pass-through, is -- is really a moot point. We see that the fact that there's a need to try to constrain natural gas prices, which we've seen that -- that -- it's been demonstrated that they can be extremely volatile. And we see a need, and we've undertaken activities to address that consumer need.

(BRIEF PAUSE)

MR. BOB PETERS: Would you agree with me, Ms. Stewart, that the consequences of your mechanistic approach are then inconsequential to the Corporation. And I don't mean that in a derogatory sense, but I mean it's -- the Corporation isn't affected whether your derivative hedging reduces gas costs or has the effect of increasing gas costs, the Corporation wants to continue to be held harmless through the use of a prudent program?

MS. LORI STEWART: I mean, my understanding is that as long as our derivatives hedging transactions are in accordance with the Public Utilities Board approved policy, that, yes, from that perspective, then I can agree with you that we would expect to continue to see those either reduction in gas costs or addition to gas costs be passed through to consumers.

MR. BOB PETERS: All right, and when you talk the mechanistic approach with the Board and myself, Ms. Stewart, you're talking about placing derivatives on 90 percent of the eligible volumes for a future nine (9) month period with cashless collars, is that correct?

MR. BRENT SANDERSON: If I might just jump in and just add a little bit of clarification as to the mechanics of how that would work.

We initiated the program by hedging twelve (12) forward months, to hedge a full one (1) year period forward, and then in each successive quarter rolling forward, as the far quarter fell off, that being months ten (10), eleven (11) and twelve (12), we would undertake to execute additional rounds of hedging transactions to place derivative hedges on what are now months ten (10), eleven (11) and twelve (12) on the far quarter of the twelfth period. So, at a minimum we retain derivative hedge instruments on nine (9) forward months, and refresh that out to a full twelve (12) months each successive quarter.

MR. BOB PETERS: Does that -- does that add up, Mr. Sanderson, to twelve (12) months being under hedged or is it -- is it only nine (9) months under hedged arrangements?

MR. BRENT SANDERSON: If you can imagine in July of 2004, our last round of derivatives hedging transactions, at the conclusion of those transactions we were hedged out for a full twelve (12) forward months, come the month of August it would be eleven (11) months, the month of September ten (10) months, and then when we get to the month of October, we would proceed to go hedge those far -- what are now far three (3) months, to hedge fully out to twelve

(12) months again.

MR. BOB PETERS: So, the way I understand the program, Mr. Sanderson and, Ms. Stewart, is that now that the program has been up and running, the activity that you take is always on the furthest out three (3) months of the twelve (12) -- twelve (12) month period under which you want to have hedges, and that's the focus of your program right now?

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: We talked, Ms. Stewart and Mr. Sanderson, about eligible volumes, and the Board has a lot of material before it in terms of what volumes consumers use over the course of the year, but can you explain to the Board, how do you determine how much are eligible volumes for which you will place derivative hedging instruments?

MR. BRENT SANDERSON: It's -- it's a number that's subject to variation depending on the percentage of market requirement that Centra supplies, as opposed to the direct purchase market and so forth.

But at any given point when we are going to market to place derivative hedges, in order to determine the volumes upon which we'll place derivative hedge instruments having regard for the percentage of the market that we currently serve. And running those numbers and average use per customer and so forth against the warmest year that has occurred in the last twenty (20) years that being the 1999, 2000 period, we come up with a forecast of what the market requirement would be.

Then working with our storage and transportation people, we come up with a calculation of the primary gas volumes that we would be able to commit to purchasing ahead of time in that warmest year scenario. Those become our eligible or warmest year volumes and we place hedges on 90 percent of that amount for each of the months in question.

MR. BOB PETERS: And while that hedging takes place on 90 percent of the warmest years' volumes, in terms of your actual volumes you've told us in some of the interrogatory responses that it really amounts to more -- closer to 57 percent in the case of fiscal '03 and 55 percent in fiscal '04. And you'd agree in the general neighbourhood that that would be the -- in terms of actual volumes, that would be the -- the amount that would be under hedge?

MR. BRENT SANDERSON: That was the actual results for those two (2) one (1) year periods that you discussed. Now that is explained by the fact that we have to forecast ten (10), eleven (11) and twelve (12) months before the fact what our purchase requirements will be not knowing with certainty what they will be.

We make our best forecast possible and to the extent that weather conditions drive differences in natural gas requirements or customers migrate to and from direct purchase, the actual amount of volumes that we would be supplying to market may be somewhat different than what we had forecast. And as a result the percentage of that load that we've hedged may be somewhat different than what the forecast would have indicated at the time we were placing the hedges.

MR. BOB PETERS: All right. With that answer, Mr. Sanderson, I'll look to the Chair for guidance on whether I should stand down before I get into the next tab in my Book of Documents, whether we should continue.

THE CHAIRPERSON: I think what we should do now is to stop your line of examination and move to Professor Miller. Do you want to introduce Professor Miller?

MR. BOB PETERS: Yes, I would be pleased. The utility Manitoba Hydro has come before the Public Utilities Board of recent day and Professor Miller represented one (1) of the Intervenors that appeared. It was actually a combined intervention on behalf of TREE and RCM and he'll introduce, I'm sure, his -- his clients in this matter.

Professor Miller has filed, Mr. Chairman, and Board Members, a -- a presentation with the Board that he would like to -- to provide and make to this Board at this time. And with little further ado I'll suggest we turn it over to Professor Miller and welcome him to a gas Hearing.

(PANEL RETIRES)

PRESENTATION BY MR. PETER MILLER:

MR. PETER MILLER: Thanks a lot. I'm seeing a lot of some of you folks and I appreciate the opportunity. Again, I'm representing TREE, that's Time to Respect Earth's Ecosystems and RCM, that's Resource Conservation Manitoba. We are two (2) non-government organizations and where we come together in this Hearing is to argue that there is a social mandate, an environmental and social mandate for energy conservation.

And not only a social mandate that's generally recognized by the -- the values that folks hold and -- but it's in legislation. It's more clearly in legislation I guess with the Manitoba Hydro at which stipulates that the -- the Utility is to provide electricity generation, distribution, and -- and use efficiency.

And perhaps this is a stumbling block for the Corporation that in acquiring Centra they feel that the Hydro Act governs the electric side of the business but perhaps not the gas side of business. And so that there seems to be some feeling on the part of the Corporation that -- that the mandate -- the legal requirement or the mandate is somewhat diluted.

Now I'm not a lawyer but I -- I did ferret out the Sustainable Development Act which is cited in the brief and it prescribes efficient use of resources. And it defines that as:

> "Encouraging and facilitating development and application of systems for proper resource pricing, demand management and resource allocation together with incentives to encourage efficient use of resources.
> And secondly employing full cost accounting to provide better information for decision makers.'

So whatever the lawyers want to argue about -- the application of the Hydro Act, I think it's fairly clear that the Sustainable Development Act does apply to the Corporation. It applies to -- to Crown Corporations and Boards that are appointed by government, so it would apply to Hydro and it would apply to the Public Utilities Board.

So in my view there's -- my admittedly lay view in terms of the law, there is all the legal support as well as whatever discretion the Board may have in recognizing public policy matters.

Surely the other side of the Corporation is trying to capitalize on -- on the climate change imperative, wants to displace Ontario Coal and so on. I guess it's a question of how schizophrenic the -- the Corporation can be and operate on different principles on the gas -- the gas side.

So we -- we basically argued our case in the electrical rate hearing and one of the recommendations we made in that Hearing was that the PUB direct Manitoba Hydro to initiate natural gas efficiency programs that parallel the current and planned electricity efficiency programs. And authorize Manitoba Hydro to file a system benefit charge on natural gas throughput to pay the costs of the program.

The economics of -- of electricity conservation and gas conservation are somewhat different, as I'm sure you're all aware, because what -- say from domestic consumption on the electricity side can be sold for more to the -- to the States and that -- that profit can be used to -- to cover the cost of the electricity DSM.

Whereas your charges are a pass through on the -- the price of Alberta gas and -- and so you don't make money when domestic customers conserve. So there is that different economics and -- and on the basis of that and whatever internal policies or interpretations of the law are operating, we were told by Mr. Lloyd Kusick (phonetic) who manages these DSM programs, that they -- whereas in the past they kind of held back on the electricity side to programs that were similar to the gas side and which did not involve any significant incentives, just customer service and -- and loans which are at rates that recover their -- their cost of borrowing that they -- they were charging ahead.

He's recently told them to charge ahead on the electric side, do a more aggressive job there than -- and not be held back by the gas DSM program. But this creates that -- that imbalance or -- or accelerates the imbalance and so now the Corporation is unable to deliver consistent gas demand side management programs.

And we don't think this is right and the -- the PUB in its first stage order agreed with us that it -- it is important to have equally aggressive programs on the gas side.

One of the economic reasons that they cited for -- for doing that is that since there's not that much difference really when it comes to heating and gas -- less difference in gas water -- in hot water, if you have conservation incentive, retrofit incentives and so on, on the electric side but not on the gas side you may encourage gas customers to switch to electricity for the conservation benefits, and thereby increase the domestic load and reduce the -- the amount of electricity available for export.

And -- and so the PUB suggested that in the --

the deterrent or the -- well, I guess the deterrent effect from making that fuel switch by having equivalent conservation opportunities for gas customers could be used as an offset to the cost of the increased gas program.

I guess the one new point in this -- this brief or would be to respond to that aspect of the PUB Order and to suggest that maybe cross-subsidization of gas DSM from electricity profits is not a good idea; that gas customers should be carrying their own burden for the DSM.

And so we stick by our recommendation of a system benefit charge as the way to do it. It's widely accepted. It's done in many different jurisdictions and we don't see why it shouldn't be done here as a way of funding the gas specific DSM programs.

And -- and finally, since this hearing is contemplating a reduction in gas rates, what better time? You simply -- I mean, you can put in the -- the charge and -- in under the amount of the reduction so customers don't feel it.

But it's there to create major investments in -- in energy conservation amongst your gas customers which is consistent with all sorts of provincial policies.

So I've just been speaking ad lib really to some of the points in the brief. Have -- has the brief been distributed? Does everyone have it?

So, I -- I detail some of these -- these points, perhaps slightly more there, but I think that's the essence of what I want to say and I'm prepared to entertain any questions that the Board or anyone else might have on that. Thank you.

THE CHAIRPERSON: Thank you, Professor Miller.

MR. BOB PETERS: I can indicate, Mr. Chairman, that the brief, I believe, was distributed and, with your permission, we could ask the -- Carol, our court reporter, to have a copy of the brief embedded in the transcript so it's there for the Board to refer to at a later date as well.

It's not one that we would necessarily mark as an exhibit because TREE and RCM are not Intervenors in the proceedings, so that would be a way of making sure that it's available for the Board and others to consider now and subsequently.

(TREE/RCM BRIEF TO THE PUB INSERTED IN SEPTEMBER 9, 2004 TRANSCRIPT)

THE CHAIRPERSON: That's fine.

MR. BOB PETERS: I don't have questions of Professor Miller. It's gracious of him to -- to offer to be available to answer them. Usually we don't grill the presenters, so to speak, but Professor Miller being familiar with the process knows that it's a process to get information to the Board, so I haven't got specific questions of him.

Although if he wanted to indicate to the Corporation whether he has calculated how much these programs should be on an annual basis and how much of a -- a system benefit charge should be -- should be charged and whether that should be by customer class or how it should be allocated might be something that would be of interest to the Corporation to consider. So I don't know if the Professor has considered that.

MR. PETER MILLER: Thanks. I certainly haven't done any new calculations for this, but in our evidence before the electrical Hearing, Mr. Lazar, our Economist, recommended a 2 percent charge and that would be on -- on -- on all the -- the, I guess it would be the distribution costs, not on the fixed charges. And he reckoned that might yield $10 million to invest in DSM. So there's a ballpark to start with.

THE CHAIRPERSON: Now, Professor Miller, you mentioned a precedent; does any immediately come to your mind?

MR. PETER MILLER: Precedent...?

THE CHAIRPERSON: For system charges to support DSM?

MR. PETER MILLER: Well, I -- I believe that Jim Hosanar (phonetic) cited some on the west coast there. I think they're a common feature on the west coast; I don't know if Ontario is beginning to get into that now, as they get more serious about conservation.

If you would like, I could, you know, check a few sources and -- and maybe forward that information to you.

THE CHAIRPERSON: That's fine. Thank you very much.

Well, thanks for attending and making a presentation, Professor Miller. Thank you very much.

MR. PETER MILLER: Okay. Thanks for having me.

THE CHAIRPERSON: Mr. Peters...?

MR. BOB PETERS: Yes, well, while we're still on the subject, Mr. Chairman, and Board Members of Presentations, I can remind the Board that back on April the 22nd or April 23rd of this year, Mr. and Mrs. Vergata, V-E-R-G-A-T-A, filed a written presentation with the Board and I propose -- again, I would provide it to the Court Reporter, and Carol could embed this in the transcript at this particular point in time, as it is another presentation.

(PRESENTATION OF MARLENE AND FRANK VERGATA

IN SEPTEMBER 9, 2004 TRANSCRIPT)

MR. BOB PETERS: I can also remind the Board and all Parties, that we can expect a presentation from a high volume firm customer next Wednesday morning at nine o'clock, being the 15th of September. So, with those comments, I will get back to the issues at hand with the Panel.

THE CHAIRPERSON: Has that letter been circulated to the Intervenors? If it hasn't --

MR. BOB PETERS: I will check that at the break; it has been provided, I believe it was provided to Centra and I'll arrange to have copies provided to the other Intervenors.

THE CHAIRPERSON: Okay.

MR. BOB PETERS: Thank you.

CENTRA PANEL; Resumed

CONTINUED CROSS-EXAMINATION BY MR. BOB PETERS:

MR. BOB PETERS: Ms. Stewart, if you could turn with me, and hopefully the Board Members, to Tab 5 of the Book of Documents that's been prepared, we see an extract from one of the interrogatories, particularly PUB/CENTRA-83(c), and it's an Attachment, and I wonder if you could let me know when you have that turned up.

MS. LORI STEWART: I have it, Mr. Peters.

MR. BOB PETERS: And, in the document, you are explaining to the Board the volumes that have been hedged as well as the total purchased volumes in various time frames; correct?

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

MR. BOB PETERS: And when we talked, I think Mr. Sanderson and I, about the percentage of hedged volumes as a total of, sorry, the amount of hedged volumes as a percentage of total volumes, he was really looking at line number 8 and the various amounts that flow from that calculation; would that be correct?

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

MR. BOB PETERS: And, on line 10, you show the financial impacts of the hedges on gas costs, and would I be correct that those numbers that are in brackets would be a reduced gas cost to consumer, and those not in brackets would be as a result of increased gas costs to consumers?

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

MR. BOB PETERS: And can you indicate to the Board where in this time line, the mechanistic price management policy came into effect?

MR. BRENT SANDERSON: Essentially, we began placing hedges in a mechanistic manner, in December of 2001.

But if you want to look at the full fiscal period in this table where the entire period was covered by a mechanistic implementation approach, it would have been the April 2002 through to March 2003, period.

MR. BOB PETERS: Is there any correlation in the Corporation's mind to go into a mechanistic approach and the fact that, gas costs have been reduced as a result of the hedging under that policy since then?

MS. LORI STEWART: The market to market results are simply a function of the market. So, no, there is no correlation, in our mind.

MR. BOB PETERS: When you show, Ms. Stewart and Mr. Sanderson, on Tab 5, which is the PUB/Centra 83 extract, the total purchased volumes, do those volumes include those under direct purchase?

MS. LORI STEWART: No, they do not.

MR. BOB PETERS: Those are system supplied gas only?

MS. LORI STEWART: That's correct.

MR. BOB PETERS: Can you explain to the Board why -- well, first of all, the western buy/sell arrangement is no longer an option or a service provided by the Corporation to brokers, is it?

MS. LORI STEWART: Just to clarify, the buy/sell service is -- is no longer available.

MR. BOB PETERS: And there is a direct purchase mechanism that the Board will hear of, the WTS arrangement or the Western Transportation Service, correct?

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

MR. BOB PETERS: And under that arrangement brokers secure their own gas and Centra transports it to city gate.

MR. HOWARD STEPHENS: That's a fair -- that's a fair comment, Mr. Peters.

MR. BOB PETERS: Am I correct, Ms. Stewart, that Centra does not hedge any of the volumes that come to Manitoba through direct purchase?

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

MR. BOB PETERS: Would I also be correct, Ms. Stewart, that Centra does not hedge any of the supplemental gas that it acquires, as well?

MS. LORI STEWART: That's correct.

MR. BOB PETERS: The next result of those answers, Ms. Stewart, is that line 6 on Tab 5, shows the Board what the total primary gas purchased for system load was in those particular years.

MR. BRENT SANDERSON: That line on line, did you say -- pardon me -- did you say line 6?

MR. BOB PETERS: I meant to.

MR. BRENT SANDERSON: Line 6 indicates the entire purchased gas volumes for system customers, including supplemental gas.

The percentages on line 8 are meant to illustrate, what percentage of our total gas purchases, both primary and supplemental, were hedged with derivative hedging instruments.

We only hedge primary gas volumes, but those hedge volumes represent thirty-six (36) and twenty (20) and 37 percent and so on, of our total overall natural gas purchases for system customers.

MR. BOB PETERS: Okay, well, thank you for that clarification, Mr. Sanderson.

While we're on the chart, Ms. Stewart, on line 10 was the financial impacts and you told me that the financial impacts will be whatever the market says they will be, and the Corporation is not guided whether that's a positive or a negative number, in its actions.

MS. LORI STEWART: That's correct. We've put into evidence what the -- the appropriate performance measure is from our perspective and it -- it's not the market to market results.

MR. BOB PETERS: And what -- can you remind the Board of what you feel is the appropriate performance measure, when looking at your program?

MS. LORI STEWART: Certainly, I'd be glad to.

The performance measure that we rely on is the percentage reduction in volatility of our primary gas sales rates, as opposed to the market to market performance or results of the program and our hedging activities.

MR. BOB PETERS: That's a nice segue Ms. Stewart, to line item 12, where you do show the Board the percent reduction in the primary gas rate volatility as a result of your hedging.

And you're suggesting that for the -- for the year that's finished, that's April of '03 to March of '04, Centra's hedging actions reduced the volatility by 20 percent.

Is that how I interpret your table?

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

MR. BOB PETERS: And how did you measure that 20 percent and come up with a 20 percent number?

MR. BRENT SANDERSON: I can jump in here and help out with that. What we do is, is we know what our primary gas rates have been over a given time period and then what we do is conduct a pro forma analysis and go back in time and recalculate on a pro forma basis what our primary gas rates would have been set at in the absence of any hedging activities.

So it's a fairly in depth and complex modelling exercise. But once we've quantified what those primary gas rates would have been in the absence of the derivative hedging program, we then compare the volatility of our actual rates over whatever time period in question to what they otherwise would have been. And if there has been a reduction in that volatility we measure that in terms of the standard deviation of the rate and calculate a percentage reduction which you see in this chart on line 12.

MR. BOB PETERS: Do I take from that answer, Mr. Sanderson, that it's not a dollar amount that determines what -- what the volatility reduction has been but rather it's more complicated through your model.

MR. BRENT SANDERSON: Well, we quantify the standard deviation in terms of a dollar amount of variability for each of the actual rates and the pro forma rates if we hadn't conducted the hedging. And then we compare the order of magnitude of the difference between those two dollar ($2) amounts. But a standard deviation is a generally accepted measure of volatility or variability.

MR. BOB PETERS: Why is there no percent volatility for the August 1, 1999 to March 2002 time period?

MR. BRENT SANDERSON: Well, we -- we haven't gone back -- or I haven't gone back and calculated the percentage reduction over that time period because they're -- we weren't conducting a derivative hedging program that would equate to the program we currently have in place.

And so we don't feel that the results would be comparable because you're mixing apples and oranges in that the -- the strategy or -- and/or policies over those different periods of time were -- were not similar to the approach that we've adopted since December 2001.

MR. BOB PETERS: Mr. Sanderson, I'm a bit taken by your explanation about the model to get the percent reduction in primary gas volatility. Presently, your primary gas set by this Board is adjusted quarterly based on 100 percent of the difference between your current rate and what the forward strip tells you it's going to be; is that correct?

MR. BRENT SANDERSON: Correct, including the mark-to-mark and impacts of any derivative hedges that we have in place at the time we calculate that rate adjustment.

MR. BOB PETERS: Yes, and you're telling the Board that not only does the -- the strip give you what the price will be, you have to go back and see what derivative instruments you've put on and what their impacts are by the current strip.

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

MR. BOB PETERS: Have you gone back and modelled the scenario as to what would happen to the volatility of your primary gas if the percent adjustment from the actual rate to the strip was something less than 100 percent as presently done by the quarterly price adjustments?

MR. BRENT SANDERSON: No, I have not.

MR. BOB PETERS: Is it intuitive or would you have to check that, Mr. Sanderson, that if the primary gas rates were set -- and let's pick 50 percent of the difference between actual primary gas rates and the rate that the strip kicked out -- would there be more or less volatility under your current program, taking into account that you would also have your -- your hedging program in place.

MR. BRENT SANDERSON: Directionally speaking, the less of the change in the forward strip that you take into rates, the lesser your rate volatility but correspondingly, your PGVA balances would be bigger.

MR. BOB PETERS: Okay, but can say that necessarily, Mr. Sanderson, if -- if your derivative hedging program may have taken out the volatility that could have been there had you reduced the amount of the increase in primary gas rates from actual to forecast.

MR. BRENT SANDERSON: Our derivative hedging activities don't take out all of the forecast price volatility. They mitigate it to -- to a certain extent. So without looking at each individual rate change scenario on the basis that you've described, intuitively I would expect that on balance, we would see a lesser amount of rate volatility but we would see bigger PGVA balances.

MR. BOB PETERS: All right, and the bigger PGVA balances brings to mind a situation a few years ago where the difference between the primary gas rate -- when it was set, it was the current rate and then 50 percent of the difference of the forward strip was a previous model that was used, is that correct?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: And under that scenario there was a situation where the PGVA grew in excess of $120 million if I recall?

MR. BRENT SANDERSON: Overall gas cost deferral balances built to an amount in excess of 120 million. The primary gas portion was just over 100 million.

MR. BOB PETERS: And so while there may be a dampened impact on volatility, the gas costs were accumulating in an unprecedented amount in the PGVA that had to subsequently be recovered from consumers as well?

MR. BRENT SANDERSON: That's correct.

MR. VINCE WARDEN: Mr. Peters, I might just add though, I don't think it was necessarily because of the program that was in place at that particular point in time. We -- that was in the 2001 December, January, 2001 time frame when we saw an unprecedented spike in gas prices. So I don't think the methodology was necessarily the reason for the build up in the PGVA at that time.

MR. BOB PETERS: Good to hear from you, Mr. Warden. But let me -- let me test you on this.

MR. VINCE WARDEN: That will depend --

MR. BOB PETERS: But let's -- would you agree with me, Mr. Warden, and I appreciate that comment, I do -- would you agree with me that if the methodology used by Centra was -- was not based on 50 percent of the difference, but was based on 100 percent of the difference, the build up in the PGVA would be less?

MR. VINCE WARDEN: Absolutely, but we would have had very large increases to consumers at that point in time as well.

MR. BOB PETERS: And we won't quibble over how much less but directionally you'd agree that was -- that would be the result?

MR. VINCE WARDEN: Yes.

MR. BOB PETERS: Ms. Stewart and Mr. Sanderson, we talked, I think before the break, the lunch break, about warmest year volumes. If the -- if the amount of volumes that were hedged was not based on 90 percent of the warmest year, but if they were hedged based on -- it was based on normal year volumes, you'd end up with approximately 85 percent of total volumes under hedge?

Do you agree with that?

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

MR. BOB PETERS: And normal year volumes are -- are what, Mr. Sanderson? What do you consider normal year volumes? How do you determine that?

MR. BRENT SANDERSON: Based on our share of the market and the various customer use factors for space heating and base load, we would apply that to the most recent ten (10) year average of effective degree days heating and we would come up with a volume forecast based on those factors.

MR. BOB PETERS: And, Ms. Stewart, why is it that you don't hedge, say, normal your volumes as opposed to your 90 percent of minimum year volumes?

MS. LORI STEWART: Well, that's a -- a bit of a complicated question. But in terms of the -- the risk neutral spectrum that exists, Mr. Peters, with consumer rates being pegged to an index at one (1) end of the spectrum representing the lowest theoretical costs, however the highest degree of volatility; and fixed price, fixed term contract which represents the highest theoretical cost, however the lowest price volatility.

If Centra was in a position where it was hedging 85 percent of its total normal year volumes as compared with the approximately two-thirds (2/3) target that we have today and that has -- has resulted in -- in actual figures in 02/03 of 57 percent of total normal year, 55 percent in 03/04 and at this -- at the time that this schedule was prepared, 61 percent of total normal year volumes.

It's clear that we would be moving rather dramatically along that spectrum in -- in terms of the price volatility versus -- price volatility versus cost. And we don't believe that that would be in sync with the risk neutral position, particularly having recently performed market research to assess and reconfirm, if you like, the risk neutral position of ratepayers.

MR. BRENT SANDERSON: I take from that answer, Ms. Stewart, that your interpretation of your customers' wishes is not to hedge more than what you're presently doing?

MS. LORI STEWART: Well, our interpretation of the market research is that it -- it supports our current hedging policy and operating principles and procedures.

The other complexities, if you like, related to hedging, you know, that degree of normal year volumes, inevitably one would find oneself in the position of a year where it was not a normal year, it was a warmer year and we would find ourselves in that over-hedged position, which could be deemed as speculative.

And, in addition, if we were hedging that degree of normal year volumes and at that point, we were over-hedged, if you imagine, perhaps being in a position then of needed to unwind those positions, you can imagine that the hedging related costs and administration -- administrative costs of the program, would begin to grow.

Right now we operate the program very efficiently and that would change in the event that we were moving to -- to that degree of hedging.

MR. BOB PETERS: Ms. Stewart, has the Corporation analysed whether hedging a higher percentage of actual volumes would have that effect? Have you done any analysis on that over the past year or two (2)?

MR. BRENT SANDERSON: I can just speak qualitatively to that. At the time that we go to place any hedge instrument, the expected outcome or payoff of that instrument is zero.

In the case of a cashless collar the statistical expectation is, is that the cap price on that collar will not be triggered and neither will the floor be triggered.

Now, ultimately, on any given month, those results can be different. But over the long term, all things being equal, over a long period of time, consistent execution of a consistent program, you would expect the net payoff to be zero, over the long run.

Having said that, because we deal in the over the counter market for these instruments, the counter parties that bring these instruments to the market for us, or allow us to place these instruments embed a small premium or margin in the price of these instruments for the service of bringing them to market.

So, over the long term, we expect that there will be a long run cost or addition to customers' gas costs as a result of the execution of this program.

Now, we -- expect it to be a very small cost. But, having said that, the more instruments we place, or the more -- more volumes that we hedge, the long run cost of the program to customers, will be higher. I don't know if that answers your question.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Stevens, I'm going to ask you to jump in here, because I have a recollection that when you were negotiating some gas contracts at one (1) point in time, you negotiated a provision that you could do price management with the contract -- the contracting party to supply the gas.

Have I recalled that correctly?

MR. HOWARD STEPHENS: Yes, our -- our existing contract that still remains in place today, I believe, still has language to that effect.

MR. BOB PETERS: All right and --

MR. HOWARD STEPHENS: It's hedging using the physical contract.

MR. BOB PETERS: And if you hedge under the physical contract, you could then hedge your -- your actual requirements whether they're normal or warmest year or coldest year, you could actually hedge to actual requirements?

MR. HOWARD STEPHENS: It's not quite as simple as that, but, conceptually and theoretically, I'll agree you.

MR. BOB PETERS: All right. And if I've got you agreeing so far, can you explain to me, why you wouldn't take advantage of that and hedge volumes because then you would eliminate one (1) of the concerns that Ms. Stewart told us about, about being over-hedged.

MS. LORI STEWART: I'll jump in here, Mr. Peters. And the reason that we don't do business with Nexen in that regard, is because I would then be violating my operating principles and procedures, which require me to do business with a counter-party that is a-rated. And Nexen does not meet that hurdle.

(BRIEF PAUSE)

MR. BOB PETERS: They're not rated high enough for you to do a financial transaction with, but they are rated high enough that you would entrust them with the entire primary gas supply for Manitobans, is what I'm -- what I'm -- where I'm going with that, Mr. Stephens, have I got that right?

MR. HOWARD STEPHENS: In general, you've characterized it correctly. But you'll have to keep in mind that we're generally on the paying end of the Gas Purchase Agreement, as opposed to, and I mean, I can't say this that this is always going to be the case, but certainly with the derivative transactions with the financial institutions, there's a much greater level of security associated with them from a credit worthy -- credit worthiness perspective.

MR. BOB PETERS: Who gives them the ratings, the credit ratings; which agency do you rely on in terms of who you will do -- do business with, Ms. Stewart?

MS. LORI STEWART: Yeah, DBRS.

MR. HOWARD STEPHENS: It -- it is the area of some debate within the company, Mr. Peters.

MR. BOB PETERS: All right. I can see that, I think. In -- in terms of the Market Survey, Ms. Stewart, that was done under your general supervision and you're -- you're conversant with the results of that?

MS. LORI STEWART: Yes, it was and yes, I am.

MR. BOB PETERS: All right. And you told Ms.

Murphy that 53 percent of your surveyed customers want you to maintain the current level of hedging, and 13 percent wanted to increase it; correct?

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

MR. BOB PETERS: And if I recall your answer to one (1) of the interrogatories, there was 27 percent wanted no hedging and 7 percent didn’t give you a response?

MS. LORI STEWART: I don’t have those results right in front of me, but -- but those numbers sound correct.

MR. BOB PETERS: In terms of the current hedging program, you established a tolerance of plus or minus five dollars ($5) a month, which translated to plus or minus sixty dollars ($60) a year; have I got that right?

MS. LORI STEWART: That was a -- a benchmark that had existed for some time, yes.

MR. BOB PETERS: Is that still a benchmark?

MS. LORI STEWART: It’s -- and I believe in an information request, we outlined that we have discontinued tracking that particular benchmark, given our transition to the performance measure -- measure outlined a few minutes ago.

MR. BOB PETERS: Your -- the benchmark was established and it led to the Corporation using the fifty (50) cent out of the money derivative, did it not?

Did it not at that point in time equate to

that volatility level?
MR. HOWARD STEPHENS: That's correct, Mr. Peters.

(BRIEF PAUSE)

MR. BOB PETERS: When the program first started and the derivative hedging started, I think, Mr. Stephens, you were confirming that the fifty (50) cent out of the money number was, that's where the genesis of it came. And it is translated through into the mechanistic program initially at least; is that not correct?
MR. HOWARD STEPHENS: Yes. And in terms of the Band that we strike for the cashless collars, it is -- it is lived on, but in terms of the performance measure, as Ms. Stewart has pointed out, it's no longer used as the performance measure.
MR. BOB PETERS: Have you, Ms. Stewart, checked your performance recently against the measure of volatility of plus or minus five dollars ($5) a month or sixty dollars ($60) on an annual basis?
MS. LORI STEWART: Mr. Sanderson may be in a position to confirm this. I believe that the last time-frame at which we had tracked the sixty dollar ($60) value, was probably in the neighbourhood of nine (9) months ago. At

that point we would have discontinued tracking that information.

MR. BRENT SANDERSON: I can confirm that Ms. Stewart's correct on that.

MR. BOB PETERS: What were the results that you -- you found back then, Ms. Stewart, in terms of tracking it on the -- on the old tolerance measure?

MR. BRENT SANDERSON: The rate -- the rate adjustments had remained within that tolerance band.

MR. BOB PETERS: And when you say, within that tolerance band, Mr. Sanderson, you're telling the Board that, as a result of your hedging in -- in normal weather, you would constrain the volatility of the customer bill to plus or minus sixty dollars ($60) a year?

MR. BRENT SANDERSON: Not in normal weather; this was on an actual weather basis.

MR. BOB PETERS: Was the -- was the hedging not designed to do plus or minus five dollars ($5) a month on a weather normalized basis?

MR. BRENT SANDERSON: Yes, so it's of one (1) order of magnitude improvement, I guess, to say that we were also remained within the band on an actual basis as well.

MR. BOB PETERS: That would just be fortunate, not as a result of any part of the program, but just fortuitous, would it not?

MR. BRENT SANDERSON: The results are what they are.

MR. BOB PETERS: Having said that it was weather normalized initially, Mr. Sanderson, what -- what you're telling the Board is that if you could constrain the gas cost to this plus or minus sixty dollars ($60) a year, not taking into account whether the weather impacts would be cumulative on top of whatever you could do by the -- by the hedging. Correct?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: And when we say that the sixty dollars ($60) a year was not to take into account the weather, recognizing in this climate the weather could have a very significant impact, certainly far greater than sixty dollars ($60) a year in terms of fluctuation.

MR. BRENT SANDERSON: Absolutely, which is one (1) of the reasons why we looked at moving away from that benchmark.

MR. BOB PETERS: Ms. Stewart, when we were looking at Tab, I believe, five (5) in the brief of documents, we talked about the reduction in primary gas volatility rates. I'm not sure if it was your direct evidence this morning to Ms. Murphy or whether it was someone else's but I was given to understand that the new reduction in volatility for the current year is 33 percent. Did I hear somebody correctly on that?

MS. LORI STEWART: Yes, that was in my direct evidence and year-to-date in ’04/’05, the reduction in volatility that we have achieved relative to primary gas sales rates is 33 percent and that covers the period April 1, 2004 to October 31, 2004.

MR. BOB PETERS: What is the specific performance measure that you strive for, Ms. Stewart; is there a specific percentage reduction number?

MS. LORI STEWART: No, there is no target, Mr. Peters.

MR. BOB PETERS: So, any reduction in volatility is considered a success of the program.

MS. LORI STEWART: Well, in fact, in the unusual occurrence where the percentage was zero, what that would indicate is simply that -- that we had moved through a period in the market where the market was unusually stable and in fact that the band wasn’t triggered on either side. So, really, it -- it remains a -- a function of the market in terms of what that percentage reduction will drive out to be.

MR. BOB PETERS: Thank you, Ms. Stewart. In terms of counterparties, you’ve already told the Board that one (1) of your requirements in your policy in your terms and conditions is that the counterparties have to have a credit rating of A or greater; is that right?

MS. LORI STEWART: Yes, that's correct.
MR. BOB PETERS: And as I understand the evidence, there's currently five (5) counterparties that you -- that you seek quotes from before you place your derivative instruments.
MS. LORI STEWART: That's correct.
MR. BOB PETERS: Are there more counterparties out there that are A-rated other than those five (5) that you have access to but choose not to use.
MS. LORI STEWART: Certainly there are -- there are more A-rated counterparties in the marketplace. We --we don't presently have an ISDA (phonetic) agreement in place with any of those counterparties other than the five (5) noted.
MR. BOB PETERS: None of the five (5) are -- are US-based are they.
MS. LORI STEWART: We do business with Citibank which is a Canadian subsidiary of -- of the US corp.
MR. BOB PETERS: It's not a requirement in your terms and conditions, though, that it be Canadian is it?
MS. LORI STEWART: No, it is not.
MR. BOB PETERS: Is -- is that a -- a deliberate decision to limit it to Canadian counterparties?
MS. LORI STEWART: No.
MR. BOB PETERS: Are you seeking any

additional ones or are you seeking to qualify any additional ones?

MS. LORI STEWART: We are considering the addition of a sixth. Negotiations -- it's really even too early to characterize it as negotiations, discussions have begun with a sixth potential counterparty, Mr. Peters. And on an ongoing basis we will assess the value of that relative to the expense of putting the additional ISDA in place.

MR. BOB PETERS: When you consider that, Ms. Stewart, isn't one (1) of the tradeoffs as to whether or not the market becomes more liquid or more competitive and you can drive a better -- a better rate.

MS. LORI STEWART: I guess, theoretically, it might be nice to have twenty (20) quotes simultaneously, however, we're a pretty small shop and we run a very efficient shop and certainly the more counterparties I add the more transactors who I need to have approved and the more underlying costs I'm going to incur.

And the value of that -- that's that judgment in terms of, how much value am I going to get when I've got, what I would describe as certainly adequate price transparency with five (5) quotes coming in.

The minimum that we require in our operating principles and procedures is three (3) quotes and we currently receive five (5).

MR. BOB PETERS: Is there quite a spread between the five (5) that respond in terms of the quotes, on a regular basis?

MS. LORI STEWART: There can be.

MR. BOB PETERS: Does the indication that there's five (5) counter parties do respond, is there any impacts on the liquidity of the market, per se, in that you don't have -- you don't have enough of a supply to go to, to find these derivative products, from the counter parties?

MS. LORI STEWART: No, we've spoken by way of the information request process, with regard to the revision that we did make, in terms of taking our volumes to the market, in two (2) tranches versus one (1).

And that was as a direct result of some concerns expressed to us, by our counter parties with regard to liquidity and since we've made that change, things have been working very, very well.

MR. BOB PETERS: Ms. Stewart, if you turn with me to Tab 6 in the book of documents, there's a schedule reproduced from your update of August 9th, schedule 5.0.0.

(BRIEF PAUSE)

And Mr. Sanderson, these are actual numbers, at this point in time? These are no longer, there's no forecasting in any of this?

MR. BRENT SANDERSON: That’s correct.

MR. BOB PETERS: And so when the Board looks down to line 47 and line 48, they will see that as a result of your hedging program, gas costs were reduced by approximately $4.6 million?

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

MR. BOB PETERS: And interestingly, here on line 48, there is a hedge impact on buy/sell supply to load. And that represented Centra’s former practice of hedging volumes that were supplied under the buy/sell arrangement?

MR. BRENT SANDERSON: Not directly. We’ve never directly hedged buy/sell load. Mr. Stephens might be able to speak a bit more about the history, but, at some time in the past, the direct purchase community, was successful in having the Board rule that they should receive a pro rata share of any hedging impacts due to the hedging activities, we undertake on behalf of the systems supply load.

So, it’s a proxy hedging impact, if you will, but, we never went out and directly hedged buy/sell supply load.

MR. HOWARD STEPHENS: Are you happy with that, Mr. Peters?

MR. BOB PETERS: I think we don’t need the history, Mr. Stephens. But, the -- what you’ve told me, Mr.

Sanderson, is that the customer who were getting their gas, their primary gas through a broker, were charged by Centra the same price as system supply customers?

MR. HOWARD STEPHENS: The system customers or the buy sell customers were charged the same sales rate, as the rest of the system customers. And we also paid them, the same rate that we paid our main supplier.

So that we preserved the margin between the sales price or sales rate, and our costs of gas, which was the important component.

MR. BOB PETERS: And Mr. Stephens, you can confirm for the Board that the buy/sell arrangement is no longer available so we won't be seeing this line 48 on subsequent schedule 5.0.0.?

MR. HOWARD STEPHENS: This should be the last vestige of it.

MR. BOB PETERS: And in terms, Ms. Stewart, of the actual hedging results -- before I leave -- before I leave Tab 6 and I expect I may come back or maybe not now, the -- you broken down schedule 5.0.0, Mr. Sanderson, into fixed costs, variable costs and supply costs, as I read this, correct?

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: And the fixed costs are the costs that would be incurred, whether or not, one (1) molecule of gas flowed down those pipeline or storage arrangements?

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: And the variable transportation costs, these variable costs are a cost that is charged, based on the volume of gas transported or put through to storage?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: And supply costs again, are simply the commodity purchase costs that you would incur depending on where you sourced your -- your commodity?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: All right. Would it be fair to say, Mr. Sanderson, that the primary effort of Mr. Stephens in terms of capacity management, really relates to trying to minimize those fixed costs that won't be -- that won't be utilized for Manitoba load but could be utilized and diminished in some other way through a transaction?

MR. BRENT SANDERSON: Subject to my getting a smack from Mr. Stephens, yes I would agree with that.

MR. BOB PETERS: I was half way through the question, I realized I should have asked him but thank you for that, Mr. Sanderson. And I'll keep an eye on Mr. Stephens for you during the Hearing here.

Ms. Stewart and Mr. Sanderson, turning to Tab

7 of the Book of Documents that you have before you, you are setting before the Board all of the transactions that you -- you conducted in fiscal 2003/'04 in terms of price management?

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

MR. BOB PETERS: And these also, Ms. Stewart, represent now actual results and not forecast results?

MS. LORI STEWART: That's correct.

MR. BOB PETERS: And these are for the system supply and this number that's on I guess line 27 at the far right hand column, would go back to the previous schedule that we reviewed and that would be the amount of the -- the impact on system supply gas, is that correct?

MS. LORI STEWART: Well you can see the two (2) component parts under the -- under the columns headed 'System Supply' and then 'Buy/Sell Supply'. The sum of which is a reduction in gas cost of $4.6 million.

MR. BOB PETERS: Ms. Stewart, when I look at the counter party list, you told me you had five (5) counter parties. I see somebody is numbered on line 15 as counter party number 6.

Is there a sixth counter party or is that just a misnumbering of the counter parties you have or has number 1 fallen away and we've got a new number 6?

MR. BRENT SANDERSON: I can confirm that number 1 has fallen away. Our list of counter parties does change over time and any counter parties which have dropped off the list it would have been because they didn't meet our minimum 'A' credit rating requirement.

MR. BOB PETERS: I won't ask you who that was but. In terms of the 'Gas Month' column -- the 'Gas Month' column, you're showing the Board the month in which the gas is to be priced?

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

MR. BOB PETERS: And every transaction type, Ms. Stewart, has been a caller, that is the cash list caller?

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

MR. BOB PETERS: And as I understand the attractive position of a costless caller that you've told the Board and I'll start on line 1, is that the caller sets a cap price of five dollars and twenty-nine cents ($5.29) and a floor price of four dollars and forty-nine cents ($4.49) and as long as you acquire the cap, you don't have to pay a premium for that type of protection?

That is if the gas cost ultimately comes down between those two (2), there's no premium to you? If it's in excess of that, likewise you've restrained it by the cap and if it's below that you have -- you have to pay the floor price?

MR. BRENT SANDERSON: I think at this juncture, it’s important to point out that if we were to pursue the same mechanistic strategy with simply a call option or cap strategy where we pay an upfront premium, long run the net financial results of the program theoretically over the long run are identical.

The benefit in zero up front premium costs comes by way of how we allocate scarce capital within the Corporation. We’re to pursue the same strategy with a fifty cent ($.50) of all the money call option strategy as opposed to have cap and a floor where the cash is caller, at any given point and time we might have as many as much as $24 million tied up in prepaid premiums.

For a strategy with the same long run expected outcome, the Corporation can find more effective uses for that $24 million in the meantime and so we choose a caller strategy to free up that capital -- prepaid capital in the near term.

MS. LORI STEWART: In terms of the impact, if the settlement price on that particular transaction and we’re looking at the -- the first tranche of the April 3 caller.

If the settlement price were to land between four dollars and forty-nine cents ($4.49) and five dollars and twenty-nine cents ($5.29), neither the counter party nor Centra would make payment or receive payment.

In the event, and this is what occurred in this particular instance, when the settlement price was higher than the agreed-to cap of five twenty-nine (5.29) the month settled at six seventy-four (6.74). You -- we can see that Centra received payment from the counter party, to the tune of $2.4 million.

In the event that that particular month had settled at a price lower than four dollars and forty-nine cents ($4.49) then Centra would have paid the counter party and -- and settled with them. So I hope that clears things up.

MR. BOB PETERS: And your example that you gave me laterally, Ms. Stewart, could be found on, say Line Number 19, where following it across, you had price protection between six dollars and thirty cents ($6.30) and six dollars and ninety-seven cents ($6.97). The market price came due at five dollars and twenty-eight cents ($5.28) which was below the floor.

You were not able to price the gas to Manitoba consumers at -- at the five dollar and twenty-eight cents ($5.28) for what you hedged, but rather you had to pay the floor price of six dollars and thirty cents ($6.30) and that resulted in gas costs being approximately $2.9 million higher than they would have been without that derivative.

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

(BRIEF PAUSE)

MR. BOB PETERS: When you set the ranges for these, Ms. Stewart, you've said fifty (50) cent out of the money is a guideline. Have I understood you correctly?

MS. LORI STEWART: Well it's firmer than a guideline, I guess from our perspective. It's always fifty (50) cents out of the money.

MR. BOB PETERS: And so when we look at the cap, is the cap always the fifty (50) cent -- it's fifty (50) cents higher than -- than what the market was on the day you placed it?

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

MR. BOB PETERS: And there's not necessarily symmetry here, is there, in terms of the cap is fifty (50) cent higher, the floor may not be fifty (50) cent lower?

MS. LORI STEWART: That's correct.

MR. BOB PETERS: And, in fact, usually the case is the floor doesn't give you the same degree of downward protection or flexibility as does the -- the upside?

MS. LORI STEWART: That's correct.

(BRIEF PAUSE)

MR. BOB PETERS: I'd like to turn with the Panel, Mr. Chairman, unless the Panel want to break at this time, but to Tab 6, briefly, of the document and then go to the approved PGVA balance or the PGVA balances for this year.

THE CHAIRPERSON: Why don't we have a short break when you get to the PGVA?

MR. BOB PETERS: All right, thank you. In terms of the 2003/04 gas costs as we saw on Tab 6, Mr. Sanderson, this now represents the final costs and you've told the Board that the total 2003/04 costs are $368.4 million. Have I got that right?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: And of those costs, on lines 37 and 38, are your primary gas costs which total approximately $268 million and those were subject to the Interim Orders that Mr. Rainkie and I spoke of this morning?

MR. BRENT SANDERSON: That's correct and in addition to that, Lines 39 and Lines 40 are also -- also make up part of our primary gas costs as well.

MR. BOB PETERS: And in addition to that, Mr. Sanderson, the hedging impacts also relate to -- to the primary gas price management program?

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

MR. BOB PETERS: And so while the actual price of your gas for '03 and '04 is now $368.4 million, when you were last before the Board you had a different amount forecasted, correct?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: And you've explained to the Board that you asked the Board to embed in the rates your forecast, and if you are incorrect in your forecast, and there are more or less costs, that difference will be found in the purchase gas variance accounts that accrue for the various categories that you have?

MR. BRENT SANDERSON: Yes, that's correct. And if I might just take a second to just add a -- one item of clarification. I wouldn't characterize it so much as our forecast of gas costs, as opposed to what the future's market tell us gas prices will be at that point in time. I just think that the distinction is important.

MR. BOB PETERS: And the future's price is the strip that you talk about as well as the impacts of the price management that the Corporation has on for that period of time?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: And -- oh I see, you don't want to be saying it's Centra's forecast, you're saying you use a mechanistic or a strip to forecast it and you're not using any subjective judgment as to what that gas cost will be?

MR. BRENT SANDERSON: Only because we feel that the future's market is the best forecast available in the market place.

MR. BOB PETERS: Well, I'm going to challenge you on that, Mr. Sanderson, when I come time to talk with Mr. Stephens, because I'm going to want his opinion as to what's going to happen to the gas costs going forward then, when we talk about the next fiscal year --

MR. HOWARD STEPHENS: And my opinions cost a lot of money.

MR. BOB PETERS: Not when you're under oath.

MR. VINCE WARDEN: We haven't been able to afford that yet.

MR. BOB PETERS: I would like to turn, with this Panel, then, Mr. Chairman, to those various deferral accounts on Tab 8 of the Book of Documents, and maybe we could take a short break for the afternoon.

THE CHAIRPERSON: So be it.

--- Upon recessing at 3:11 p.m.
--- Upon resuming at 3:24 p.m.

THE CHAIRPERSON: Mr. Peters, you want to rev up your engines again?

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Yes, I do and I'm going to give an opportunity to Mr. Stephens to reflect out loud on an answer that he gave previously that I think he may want to supplement or change.

MR. HOWARD STEPHENS: Yes, you asked me whether or not at one point we had pricing structures -- that's from -- I'll use, embedded in our physical supply contracts; that was in the first term agreement with TransCanada Energy. And when they assigned those contracts over to Mirant we had that provision struck because Mirant did not have a substantial -- a substantive credit rating.

MR. BOB PETERS: All right. So, even if it was an option in the past it's no longer an option because it's not even available under the assigned contract.

MR. HOWARD STEPHENS: Not only the assigned contract but we'll get into today's -- the new contract, post two thousand (2000) -- post doc -- November 1st, 2004 and we'll discuss it from there.

MR. BOB PETERS: Appreciate that. Mr. Sanderson, I'd like to tidy up one point and make one request of you by way of undertaking. On Tab 6 of the brief of documents that you have before you that I'm using is an updated copy of Schedule 5.0.0 and those you've told the Board are your actual gas costs for which you want final approval in this application, correct?

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

MR. BOB PETERS: Mr. Sanderson, could you on a -- on one sheet of paper provide a comparison or, if you will, of actual gas costs from the prior three (3) years in addition to this one?

MR. BRENT SANDERSON: I can do that, yes.

MR. BOB PETERS: And because these are actual gas costs they would be influenced largely by the weather that occurred in those periods of time, correct?

MR. BRENT SANDERSON: As well as pipeline toll changes, as well as volatile market prices -- as well.

MR. BOB PETERS: All right. And because we’ll see those pricing changes on the various line items, I wonder if you could add an additional line item that would reflect the effective degree days for the -- for the various periods under review just so we can see what the degree day differences were between the -- between the various years?

MR. BRENT SANDERSON: I can do that. Might I ask a question for clarification? Were you looking for the line by line details similar to this schedule or you’re just looking for bottom line totals?

MR. BOB PETERS: No, I’d like all sixty-five (65) lines compared, to the extent that they are comparable. These have been done. You’ve got them sitting probably back at the office; would I be correct in assuming that?

MR. BRENT SANDERSON: They're around, yes.

MR. BOB PETERS: All right. If you could locate them that would be of assistance to the Board and we'd ask for that by way of an undertaking?

MR. BRENT SANDERSON: I'll undertake to provide that to you?

MS. LORI STEWART: You're looking -- You're looking to go back to the year 2000 and 2001; is that correct?

MR. BRENT SANDERSON: Yes, it is.

MS. LORI STEWART: Thank you.

--- UNDERTAKING NO. 2: Provide a comparison of actual gas costs from the prior three (3) years in addition to this one.

MR. BOB PETERS: Mr. Sanderson and Ms. Stewart -- I mean, Mr. Stephens, we were on Tab 8 of the book of documents and I wanted to have you turn to that with me and assist the Board.

This is the summary of all of the gas cost deferral accounts on a final basis that you've calculated and that you're proposing to refund by way of rate riders; would that be correct?

MR. BRENT SANDERSON: That's correct. I just might add for clarification that the balances reflected in this schedule are truly actuals up to the end of May of 2004. So, the June 2004 through October 2004 components of these balances are still forecasted but not subject to a significant amount of variability due to the fact that it's only -- that forecast element would just be largely carrying costs and a small amount of rider recoveries in the months of June and July.

MR. BOB PETERS: Can the Board take from that, Mr. Sanderson, that when they look to see whether they will approve your request, they should look at the numbers on this as being the numbers you're being asked to approve and to embed in the rate riders and any difference from these numbers, will be brought to their attention, in a subsequent year, by way of a rate rider that captures the earlier balances?

MR. BRENT SANDERSON: I can confirm that, yes.

(BRIEF PAUSE)

MR. BOB PETERS: This update, Mr. Sanderson, if I look down to -- look at the totals that you're showing the Board, is that the total for all accounts, as at October 31, you are asking the Board for a -- a refund of $16.5 million?

MR. BRENT SANDERSON: Correct.

(BRIEF PAUSE)

MR. BOB PETERS: Just hate to do math in public, Mr. Sanderson but, I was -- I was looking at line 13 and backing out line 2, and that would be the $15.6 million of -- of costs that were forecast last time you were before the Board to set these rates, and they were $15.6 million higher; have I got that right?

MR. BRENT SANDERSON: Essentially, that’s correct, yes.

MR. BOB PETERS: And then when I add that $15.6 million with the previous rider, you call it on line 2, July 31, ’03, Prior Period Gas Deferrals, that comes up with a total of $17.3 million?

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: In terms of calculating the amount that is to be refunded, the sixteen point five five three (16.553) number is the number that you want this Board to focus in on, correct?

MR. BRENT SANDERSON: That’s correct.

MR. BOB PETERS: And the carrying costs -- I don't think we've talked about those, Mr. Sanderson, but, if monies are owed to your consumers, do they get interest or carrying costs on that money?

MR. BRENT SANDERSON: They do --

MR. BOB PETERS: At what --

MR. BRENT SANDERSON: -- as well as if they owe money to the Corporation, it works both ways.

MR. BOB PETERS: All right. So if they owe the Corporation money, you charge them interest. If the Corporation has money, that's owed to the consumers, you add interest to it, as you continue to hold it?

MR. BRENT SANDERSON: We pay them interest, yes.

MR. BOB PETERS: And are the rates that you collect and pay exactly the same?

MR. BRENT SANDERSON: Yes.

MR. BOB PETERS: And how is that rate determined?

MR. BRENT SANDERSON: It's calculated at Manitoba Hydro's short term cost to debt, plus a provincial guarantee fee of .95 percent.

MR. BOB PETERS: Mr. Sanderson, I don't want to go through each of these items in detail, but the details actually are found in Tab 5, you've revised them in your filing, correct, in the -- in the subsequent schedules to this one?

MR. BRENT SANDERSON: That's correct.

MR. BOB PETERS: But, I do see on line number five, the supplemental gas PGVA, you're showing that there's $11.1 million that is sitting in a surplus position, owed to consumers, correct?

MR. BRENT SANDERSON: Correct.

MR. BOB PETERS: When I turn back to Tab 6 of the book of documents, which is your schedule 5.0.0, excuse me, updated for August the 9th, under supplementary gas, can you identify the lines on which would represent your actual supplemental gas purchases?

MR. BRENT SANDERSON: Supplemental gas components are identified on lines 41, 42, 43, 44, 45 and 46, inclusive.

MR. BOB PETERS: Are any of the surplus monies in the supplementary gas -- supplemental gas PGVA, attributed to fixed costs?

MR. BRENT SANDERSON: No, they're not.

MR. BOB PETERS: With -- without the aid of a calculator, Mr. Sanderson, can you tell the Board approximately what were your supplemental gas costs for '03/'04 in total?

MR. BRENT SANDERSON: If you'll just give me one second I can give you the exact amount.

MR. BOB PETERS: Mr. Sanderson, maybe I can beat you to it. I -- I think I have that in Tab 10 of the Book of Documents, Schedule 6.2.4. If -- I'll retract that -- that's a forecast, that is not your actual.

(BRIEF PAUSE)

MR. BRENT SANDERSON: Our actual 2003/2004 supplemental gas costs were approximately $20.7 million.

MR. BOB PETERS: And if that was your actual costs, would the Board be correct in deducing that you had forecast they would be more in the range of thirty-one (31) or $32 million?

MR. BRENT SANDERSON: Not entirely. I'm sorry. Not entirely. The residual balance in the supplemental PGVA account is comprised of not only a lesser amount of inflows into that account in terms of cost than was forecast but also differences in the amount of outflows or weighted average cost of gas that were recovered in rates relative to the forecast, so a combination of the two (2).

MR. BOB PETERS: Okay. Thank you for that clarification. Mr. Stephens, I want to turn with you, sir, to the discussion on what I'll call the blank page analysis and I took from your direct evidence to Ms. Murphy, that's it’s an area that you had primary responsibility for?

MR. HOWARD STEPHENS: I guess I’ll wait to see what your questions are before I agree to that.

MR. BOB PETERS: Mr. Stephens, without going too much into history as you and I tend to do here, the PUB has requested Centra in past to review its gas supply, it’s storage and transportation portfolio, correct?

MR. HOWARD STEPHENS: It seems to me that the first time I sat before this Board I was asked a question with respect to our portfolio and whether it was appropriate or not. Giving you a bit of a history lesson, we did an in-house review in 1998, filed it with the Board. It came to very much the same conclusion -- conclusions that IGC did as well as the prior more comprehensive review that was done in 1990 which led to the 1993 ANR storage arrangements.

And then as a result of the ’98 study that I referred to, it was found out to be comprehensive enough. So, I agreed at that point in time that it was appropriate -- it was appropriate for us to look at our portfolio from a more comprehensive perspective, unfettered by existing contracts.

MR. BOB PETERS: And what you were hoping to accomplish, Mr. Stephens, was to start off with what, in the vernacular, we call a blank page; if you were to start all over again and you didn’t have these fixed contractual agreements for storage or gas supply or transportation and see what would be optimum for the Manitoba consumers?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And you out sourced that through the IGC consulting group out of, I believe it was out of Texas?

MR. HOWARD STEPHENS: Yeah, Houston, Texas, International Gas Consultant.

MR. BOB PETERS: And for IGC to prepare their blank page analysis -- that's the document dated August 21, '03 and it's been filed by the Board, I believe it was August 28 of 2003?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: Centra gave IGC the specific details that it needed to prepare that report in terms of volumes and customer loads and patterns?

MR. HOWARD STEPHENS: Any and all information they required to do the analysis.

MR. BOB PETERS: And Centra even had an opportunity to review a draft report by IGC before it was finalized; would that be correct?

MR. HOWARD STEPHENS: To ensure that they had not made any significant technical errors or misunderstandings in terms of the arrangements that we had in place.

MR. BOB PETERS: Did they make any errors or have any misunderstandings about the arrangements you have in place?

MR. HOWARD STEPHENS: The majority of the corrections that we would have made would have been nit -- nits -- I will -- spelling mistakes; that sort of thing.

MR. BOB PETERS: All right. But overall, their understanding of your system was not erroneous from your perspective?

MR. HOWARD STEPHENS: No, they had a remarkably good understanding of the system but -- and it was reflected in the fact that we spent a good deal of time at the very front-end of the process, discussing what the current arrangements were, and what the limitations, et cetera, were, so, they -- they did get that benefit.

MR. BOB PETERS: The report that was filed by IGC is a final report?

MR. HOWARD STEPHENS: It is.

MR. BOB PETERS: What cost was that to the Company?

MR. HOWARD STEPHENS: I was afraid you were going to ask me that. It's somewhere in the order of four hundred and fifty thousand dollars ($450,000). I would have to check the actual number, Mr. Peters. I haven't got it with me.

MR. BOB PETERS: And, this would be in US funds?

MR. HOWARD STEPHENS: No, that's Canadian dollars.

MR. BOB PETERS: In addition to the report from IGC, Centra's management also responded to the report, and you filed that with the Board as well; correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And in terms of filing the blank page analysis in these Proceedings, it's the Corporation's view that if parties have suggestions or comments, this would be the forum in which that should come out, before the Company embarks on some specific actions that may be related directly to the blank page analysis?

MR. HOWARD STEPHENS: Certainly if Parties have concerns, I mean, we're prepared to listen and to do something with them, I mean, from that perspective, or from my perspective. In terms of what I've seen in terms of the report, I think that IGC has been very comprehensive.

(BRIEF PAUSE)

MR. BOB PETERS: You've told the Board, through this Panel, some of the existing assets that the Corporation has, both in their -- in the maps that you've shown us, and when we looked at Tab 6 in Schedule 5.0.0, but you would say -- you would agree with me, Mr. Stephens, that the assets of the Corporation has to support its portfolio, are captured in numerical form, based on the charges that flow to these -- to these schedules?

MR. HOWARD STEPHENS: Which schedules are you referring to, Mr. Peters?

MR. BOB PETERS: Schedule 5.0.0, as found at Tab 6.

MR. HOWARD STEPHENS: I'll agree to that, yes.

MR. BOB PETERS: And that's really a comprehensive summary from Mr. Sanderson's group, of all of the costs that underpin your ability to supply the Manitoba load?

MR. HOWARD STEPHENS: That's a comprehensive list of all of our assets and the costs associated with them.

MR. BOB PETERS: And -- and, if that is your costs, what is the purpose of your asking for a blank page analysis through the consultants? What do you want them to identify for you?

MR. HOWARD STEPHENS: If there's a potentially lower cost alternative that will satisfy the Manitoba market without the incumbent weaknesses of the existing portfolio.

MR. BOB PETERS: Does the mix of assets that you need to -- to supply your portfolio depend on the commodity cost in any way?

MR. HOWARD STEPHENS: Much -- no, I guess the short answer is, no. To some extent there is an impact, but it's very minimal. The larger impact would be the function of basis differentials, the differential between price in Manitoba versus Ontario, or in Canada versus the United States.

MR. BOB PETERS: You're saying that those basis differentials of the commodity would impact which options might be optimal to support the Manitoba load?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: What impact does the rising Canadian dollar have, of recent date, on that impact?

MR. HOWARD STEPHENS: The higher the Canadian dollar gets, the more attractive the US assets become.

MR. BOB PETERS: Well then, let's turn to -- your major US asset would be your storage arrangement; would that be correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And you've told the Board, and I have it somewhere here, that you're in a contractual arrangement with a Company called ANR, and you are committed to them for approximately $14.7 million US a year?

MR. HOWARD STEPHENS: Fourteen million, six hundred and seventy six ($14,676,000), US

MR. BOB PETERS: And the interesting part of your answer through Ms. Murphy that the Board heard this morning was, that's a cap on how much you have to pay to ANR for getting gas into storage, but I take it, in some years it could be less than that?

MR. HOWARD STEPHENS: Yes, to the extent that their tolls came in lower than what the tolls are that are in a stated contracts, we would get charged the lesser of the toll or the revenue cap.

And I want to be clear that this is only for those ANR arrangements, not for the Great Lake components.

MR. BOB PETERS: I'm sorry, the last point was that it was only for the...?

MR. HOWARD STEPHENS: These are only for the ANR arrangements, the pipeline and storage arrangements, not the Great Lakes component.

MR. BOB PETERS: And, in fact, ANR entered into a contract with Great Lakes that up until recently, in any event, they simply assigned over to you at no additional cost, to what they were -- to what they were paying?

MR. HOWARD STEPHENS: It was part of the late 80's approach to marketing assets. I mean the pipeline companies would try to bundle up a series of assets and sell them to a customer and I mean all they really did, was they signed the contract on our behalf, but, they passed the cost straight through to us.

And we had the responsibility to operate them under the terms of the contract.

MR. BOB PETERS: All right. Do you read the IGC -- IGC recommendation to increase your underground storage with ANR; that's one (1) of their recommendations?

MR. HOWARD STEPHENS: Yes, that's one (1) of their recommendations.

MR. BOB PETERS: And they also say that you should add salt cavern storage, probably in Saskatchewan?

MR. HOWARD STEPHENS: Yes, I believe, we've been saying that for about fifteen (15) years now.

MR. BOB PETERS: They have or Centra has?

MR. HOWARD STEPHENS: Centra has.

MR. BOB PETERS: You still don't have it do you?

MR. HOWARD STEPHENS: I'm working on it.

MR. BOB PETERS: If the -- if the -- backing up then in terms of what the recommendations are, does Centra believe that increasing ANR storage is an appropriate response?

MR. HOWARD STEPHENS: Mr. Warden alluded to the fact that this morning, in his opening comments, that we are doing some internal evaluation, and financial modelling.

And before I would answer that question, I would like to see the results of that.

MR. BOB PETERS: When you say the results, you want to have a financial analysis as to cost versus other alternatives?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: Is that being undertaken?

MR. HOWARD STEPHENS: It is underway now

MR. BOB PETERS: And what was the approximate completion date on that?

MR. HOWARD STEPHENS: I believe, Mr. Warden, referred to the first quarter of 2005.

(BRIEF PAUSE)

MR. BOB PETERS: The -- the blank page analysis, Mr. Stephens, was to pretend you were -- I use not the word pretend, that you were unfettered by any existing contracts, but, in the real world, you're committed to ANR by contract through to March 31st of 2013, correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: All right. You've indicated as well, then that the company is assessing that storage situation. And turning to transportation recommendations, one (1) of the recommendations was for Centra to firm up transportation to meet the firm peak requirement; is that correct?

MR. HOWARD STEPHENS: Their long term recommendation was that we should be contracting to satisfy our firm peak requirement, yes.

MR. BOB PETERS: And this morning, you took the Board through Tab 3 of the Book of Documents, in particular, attachment 3, which was the coloured graph that demonstrated that perhaps 20 percent of your -- of your daily delivery was not supported by a -- a fixed or firm contract; is that correct?

MR. HOWARD STEPHENS: That’s correct, sir.

MR. BOB PETERS: And one (1) of the recommendations you’ve acknowledged from the blank page analysis was to firm up some transportation so that that didn’t have to remain, at risk, if you will?

MR. HOWARD STEPHENS: That’s correct. I think I -- and in previous proceedings, I’ve expressed my increasing discomfort with the Amalgam (phonetic) one contracted peak day that we’ve had exposed.

The IGC report just confirmed that level of discomfort and from that perspective, we go into the winter now and not necessarily with hard assets then going back to the soft assets - a term that I coined and I wished I hadn’t

- where we enter into capacity management arrangements which provide us a component of peaking service at a very low cost, if any cost.

MR. BOB PETERS: Mr. Stephens, you will acknowledge that there is a portion of your peak load that's at risk, because of there being no underlying hard assets to support it?

MR. HOWARD STEPHENS: It's at risk because there are no hard assets in place, but I do have an agreement for a soft asset arrangement that provides me with five (5) days -- no, seven (7) days at fifty thousand (50,000) Gigajoules per day, on my call, firm capacity, and that will satisfy that firm day coverage for the most part.

MR. BOB PETERS: That's not an asset that you have to pay for if you don't use?

MR. HOWARD STEPHENS: That's an asset that's -- it's a part of a capacity management arrangement -- and I was trying to find a reference in here that explains it very well.

But the long and short of it is, we've agreed with a counter-part to exchange a certain volume of gas over the course of the winter. That exchange has a value associated with it.

The counter-part goes away to the market place, based upon his asset mix and determines what his cost is going to be applied to us with the peaking service that we're looking for.

Then he divides that cost by the amount of volume, and the basis differential for the exchange and we then come to an agreement as to how much gas we will exchange without charging them a fee.

MR. BOB PETERS: But that doesn't cover off the entire seventy-one point seven seven (71.77) terajoules, does it?

MR. HOWARD STEPHENS: No, it covers off fifty thousand (50,000) of it, and the extra twenty thousand (20,000), I'm sure I can find.

MR. BOB PETERS: Well, let's just talk about your assurance or your comfort level in finding it.

Would it be a fair statement to make to the Board that Centra has never not been able to supply firm customer demands in Manitoba?

MR. HOWARD STEPHENS: No, we have never been in the circumstance where we could not serve the firm customer requirements. And as I indicated before, we had a near peak day during the course of the last winter, where we were able to serve not only the entire firm load, but the interruptible as well.

MR. VINCE WARDEN: Mr. Peters, I think it's important that we be very clear on this point. There's no risk that the Manitoba consumer will be short of gas. We're talking about price here, what -- what price will we have to pay for that shortfall that we don't have on contract. We could very well firm up that contract, but it would be at a substantial price.

MR. BOB PETERS: And therefore, Mr. Warden, the reluctance of the Corporation to firm it up has been that the cost may be greater than the benefit?

MR. VINCE WARDEN: Absolutely it would.

MR. BOB PETERS: And, if the cost was greater than the benefit, you would be driving up gas costs for all consumers, or at least those in the class that would be affected by the decision you made, who are left right now unprotected?

MR. VINCE WARDEN: Yes, exactly.

MR. BOB PETERS: Would it be fair, Mr. Stephens or Mr. Warden, that the seventy-one point seven seven (71.77) terajoules of supply at risk of the price now, is that by any particular class, or is that all system customers that would bear a portion of any additional costs used to firm up that load?

MR. HOWARD STEPHENS: That would be all system customers. I would imagine in a circumstance like that, if we ran up a significant PGVA balance, we'd have an exceptional circumstance, because we've had an exceptionally cold winter, and we would have to deal with -- with the mountain at the deferral account, and assign the costs to the customers perhaps on a pro-rata basis. I'm making a number of assumptions there, but...

MR. BOB PETERS: And the base assumption that we've heard maybe from Mr. Warden then is, that the Corporation is confident that it can always get gas to meet Manitobans' needs, but the outstanding risk is that of price for that part that's not under a firm or fixed or hard contract?

(BRIEF PAUSE)

MR. VINCE WARDEN: Yes, Mr. Peters. We know that TransCanada Pipelines has a surplus capacity on their pipe, and this is the difficulty we're having with investing a huge sum of money in storages, as long as the empty pipe is flowing right by our doorstep, then is it really necessary for us to go out and build that additional storage?

And that's why we started having discussions with TransCanada Pipe, as to whether or not we could have, in effect, virtual storage on their pipe. That didn't come to fruition for a number of different reasons, and so we're back looking at the economics of storage.

But it's really an economic decision as to whether or not we proceed with storage. Not a -- not a risk as far as supplying the Manitoba customers with gas.

MR. BOB PETERS: Thank you, Mr. Warden. Do I recall correctly your direct evidence, sir, that the cost of storage has been ball parked by Centra at $50 million?

MR. VINCE WARDEN: Well this is the price that was derived by IGC.

MR. HOWARD STEPHENS: And you're doing independent investigations to see if that's the case?

MR. VINCE WARDEN: Well there are investigations whether or not we can support -- there's a benefit to consumers of -- with that kind of expenditure whether we can get a return on that investment.

MR. BOB PETERS: And, Mr. Warden and Mr. Stephens, Mr. Warden has told the Board that Trans Canada Pipeline has a -- has some unutilized capacity. Have you any handle on how much unutilized capacity they have? Flowing or available going past Winnipeg?

MR. HOWARD STEPHENS: On the availability capacity of two (2) petajoules per day -- seven (7) petajoules per day, they have two (2) petajoules currently on contract.

MR. BOB PETERS: And would it be -- would it be your reading of the -- of the blank page analysis that your consultants in Texas are envisioning a day when that two

(2) petajoule surplus is gone?

MR. HOWARD STEPHENS: Yes, they're -- they're -- they point to the fact that Trans Canada is depreciating its pipeline and is positioning themselves very well to access Northern Gas. It's a multi pronged and a very complex issue in terms of how the gas market's going to play itself out over the next several years because at the same time you're -- I just finished reading an article about Trans Canada and Petro Canada building an LNG facility on the east coast.

And we've got Gas Metropolitan doing the same thing. So we could see gas coming from the east and moving to the west. So there is -- there are a number of -- or a variety or variables associated with this.

MR. BOB PETERS: I was wondering if we could raise that first, Mr. Stephens, but that LNG plant that was in the media of recent days and there was a number of plants that are either under construction or under consideration and a total of six (6) for Canada I thought?

MR. HOWARD STEPHENS: That sounds correct, yes.

MR. BOB PETERS: And are you suggesting to the Board that you can envision a scenario where you could access LNG for the Manitoba load?

MR. HOWARD STEPHENS: Well it may displace gas that would ordinarily come with the WCSB which -- out of Alberta and as a result potentially reduce price and make the supply more secure.

I guess the one thing that we did find and the -- one of the drivers behind the IGC recommendation for South Cavern storage is it is very much more difficult to acquire gas that requires a lot of variability in terms of the contract requirements.

And I talked about the flexibility that we had under the -- have under the new Nexen contracts. The fact that we only had nine (9) counterparts respond out of about twenty (20) major counterparts that were invited to respond is indicative to me that -- well there's two (2) things going on.

First of all the major producers don't -- aren't very aggressive in terms of marketing the product. But secondly, they aren't very interested in selling gas and to anything but a base load market. So the South Cavern storage has that benefit associated with it in terms of smoothing out our purchases.

MR. BOB PETERS: And that's being factored into the economic analysis model?

MR. HOWARD STEPHENS: Well sin fact, IGC has without identifying it as a line item, but has incorporated a component of the savings associated with that in their analysis.

MR. BOB PETERS: All right, if I can quickly cover another area of that blank page analysis, one of the recommendations made by the consultant was that Centra not pursue ownership and production of natural gas resources on its own. Is that -- have I got that correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And I'm not sure if where I've heard it, I think other than it came from a panel of Centra witnesses that at one point Centra was investigating whether ownership of natural gas wells would be beneficial to Manitobans, is that correct?

MR. HOWARD STEPHENS: We -- we said we'd leave no stone unturned, we didn't.

MR. BOB PETERS: All right. And the recommendation is you don't un-turn that stone, what's been the corporate view since the report?

MR. HOWARD STEPHENS: Still the same. It's -- given our risk profile, given the very small amount of gas that we can obtain and, I mean, and really minimal benefits. I mean it's a high risk venture with very little opportunity for upside.

MR. BOB PETERS: So it's not an area that you're actively pursuing?

MR. HOWARD STEPHENS: It's very, very far back on the shelf.

MR. BOB PETERS: All right. And in terms of gas purchasing strategy, there’s a recommendation that I understood from IGC that you let the contracts you have expire; is that what you did?

MR. HOWARD STEPHENS: I let them expire -- or they will expire, October 31st.

MR. BOB PETERS: And your response was, you’re going to let that agreement expire. You had previously, Mr. Stephens, had an arrangement that went back many, many, many years that kept being renewed or extended; would that be fair?

MR. HOWARD STEPHENS: Subject to the major renegotiation we did in 2000, yes, it was. I mean, it went back to the beginning of time, 1989.

MR. BOB PETERS: All right. That’s about the beginning of my time. But, these gas supply contract was back then a long term contract and that’s now the one that’s going to expire on Halloween of this year?

MR. HOWARD STEPHENS: That’s correct.

MR. BOB PETERS: And to that end, you’ve told the Board in your direct, that you’ve issued some requests for proposals and you’ve taken some steps in respect of that, correct?

MR. HOWARD STEPHENS: That’s correct.

MR. BOB PETERS: Was it not also IGC’s suggestion that you not commit any more than 25 to 40 percent of supply to any one company?

MR. HOWARD STEPHENS: Suggestion, recommendation, I would agree, that yes that was.

MR. BOB PETERS: And you didn’t follow that, did you?

MR. HOWARD STEPHENS: No.

MR. BOB PETERS: Why didn’t you follow that?

MR. HOWARD STEPHENS: I think IGC’s recommendation is a very sound one from motherhood and apple pie perspective. But, when it came down to the final analysis, in terms of looking at the three (3) criteria that I was looking very seriously, that being, price -- not necessarily in this order, but, price, security of supply and flexibility, Nexen had the rest of the proposers beat by a country mile.

MR. BOB PETERS: Did you attempt to negotiate any flexibility or security or pricing with the other parties who responded to the RFPs to see if you could diversify your portfolio of supply?

MR. HOWARD STEPHENS: We tried to keep the process as pure as possible, with as little interaction between the counterparts and ourselves so that nobody could even claim an unfair bias.

But, there was some back and forth with other counterparts that were very close, but, as you can see by the results, in terms of the evidence that's before you, I mean, in the final analysis Nexen carried the day.

MR. BOB PETERS: And the IGC suggestion on gas purchase strategy was that you would stagger the termination dates of those various multiple suppliers and that hasn't been afforded because you've now hitched your wagon to Nexen again?

MR. HOWARD STEPHENS: Yes, there's nothing to say though that at the end of the three (3) year term that I can't hitch my wagon to only half of Nexen at the next go-around and then buy something from somebody else.

MR. BOB PETERS: Well, there was -- I'm not sure I recall correctly, but, there was an option in there for renewal with Nexen, is that correct?

MR. HOWARD STEPHENS: Yeah, we can extend it either by one (1) or two (2) years.

MR. BOB PETERS: But, it has to be -- it's not a -- it's not your sole option, it's their choice, as well?

MR. HOWARD STEPHENS: By mutual agreement.

MR. BOB PETERS: All right. And also IGC was suggesting in that blank page analysis that you could use a combination of term contracts, daily spot market deals and maybe even some intra-day purchasing.

How did you deal with that in terms of your negotiation with -- or sorry, your supply arrangement with Nexen?

MR. HOWARD STEPHENS: Well, we've been down the road where we were buying gas under the TCE baseload contract, we were in the market on a day-to-day basis buying gas in the marketplace.

Certainly, when we entered into the renegotiated TCE contract and then subsequently as it was assigned to Morrant (phonetic) and then finally to Nexen, we had much more flexibility, much more price certainty and we had firm supplies every day.

And that is the one (1) component of it that swung it in my favour -- or in their favour from my perspective.

MR. BOB PETERS: Maybe my last line of questioning for today, recognizing the time, Mr. Stephens, is that you've walked with me through some of the recommendations that were made by IGC and you started your answers to me by suggesting that IGC really vindicated or confirmed the in-house review you did back in 1998.

Is that correct?

MR. HOWARD STEPHENS: That's correct.

MR. BOB PETERS: And so what I hear you've done is you've spent four hundred and some thousand dollars on an IGC study.

What value has that brought to the Corporation and your ratepayers?

MR. HOWARD STEPHENS: Oh, IGC I think brought a much more comprehensive overview of the existing market, and the circumstances surrounding it.

In 1998 the market was a much different place than what it is when IGC performed the analysis. And indeed the environment continues to change, as we just finished talking about with the advent of LNG, et cetera.

So I guess it's from that perspective, I think, that having a third-party objective perspective on things is always of value. I come to the table with certain prejudices and biases and that -- was trying to get around -- away from that as much as we could.

MR. BOB PETERS: But I still don't hear you saying you're embracing any of their recommendations that -- that we've talked about.

MR. HOWARD STEPHENS: For the most part, I agree at a -- very strongly with IGC's report. There are some areas that I have some reservations but it's just a matter of differences and professional opinion.

MR. BOB PETERS: Mr. Chairman, in light of the hour, I would suggest this could be a time to adjourn and I'll finish with this panel, I expect, tomorrow morning and I would indicate that I believe Municipal and Direct will precede CAC/MSOS tomorrow afternoon to ask questions of this panel.

THE CHAIRPERSON: Very good. Thank you everyone and, in particular, thanks to the panel. It’s been a good start to the day and a lot of to-and-fro. Thank you very much.

--- Upon adjourning at 4:05 p.m.

Certified Correct,

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Carol Wilkinson, Ms.