MANITOBA PUBLIC UTILITIES BOARD

Re: CENTRA GAS MANITOBA INC.

COST OF GAS APPLICATION

2015/16

Before Board Panel:

Regis Gosselin - Board Chairperson

Marilyn Kapitany - Board Member

Neil Duboff - Board Member

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

September 28th, 2015

Pages 1 to 301

APPEARANCES

Sven Hombach	)Board Counsel
Brent Czarnecki	)Centra Gas Manitoba)Inc.
Brian Meronek, Q.C.	)CAC (Manitoba) Inc.

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--- Upon commencing at 8:58 a.m.

THE CHAIRPERSON: Bonjour, mademoiselles et messieurs. Good morning, everyone. Nice and early, so without further ado, I'd like to welcome to the oral -- oral evidence portion of Centra Gas's -- Centra Gas Manitoba Inc.'s 2015/'16 cost-of-gas application.

My name is Regis Gosselin. I'm the chairman of the Public Utilities Board and will be one (1) of the three (3) panel members deciding this application. With me are Board members Marilyn Kapitany and Mr. Neil Duboff. So thank you very much, both of you, for participating in this panel. I know you're both very busy, so thank you very much.

The panel is assisted in this hearing by its associated secretary Kurt Simonsen and Diana Villegas who always does a wonderful job of keeping everyone organized. So thank you, Diana, and I also thank you, Kurt, for your work.

The Board is also assisted by technical advisors Roger Cathcart, Brady Ryall, as well as Board counsel Sven Hombach. And I notice there's a new advisor here, David Bonin. So welcome to all of you.

On behalf of the panel, I'd like to

welcome back Centra, its representatives and counsel, as well as Intervenor representatives and their counsel. So welcome.

I'll -- I would also like to congratulate Mr. Rainkie who was -- who has taken over as Manitoba Hydro's CEO on an interim basis. So congratulations, Mr. Rainkie, and -- and best wishes with that. Mr. Rainkie, we appreciate your being here today to answer questions on this application despite your new responsibilities -- your two (2) jobs actually, yeah.

The Board has approved two (2) Intervenors for this hearing, namely the Consumers Association of Canada and Just Energy.

To date, there has been written pre-filed evidence from Central and the Consumers Association of Canada, as well as one (1) round of written Information Requests from each party.

Beginning today, parties will have the opportunity to provide oral evidence and cross-examine witnesses. We welcome the efforts of the parties in the hearing -- in the hearing room to test and explore the evidence which will assist the panel in fulfilling the Board's rate-making function.

The hearing is scheduled for three (3)

days, with later dates having been set aside for written closing -- written closing submissions as well as oral closing arguments, if required.

Now, we've indicated to -- to the parties that we're prepared to sit later in the day to make sure that we complete the hearing process within the three (3) days that have been allocated. So let's hopefully make sure that we are succinct in our work.

This is a cost-of-gas application which primarily deals with the costs Centra incurred for gas and transportation to Manitoba. It's not a full examination of Centra's non-gas costs which usually happens at a general rate application.

While gos -- gas and transportation costs are flow-through costs on which Centra is not seeking a pro -- seeking a profit, the Board must satisfy itself that the costs were prudently incurred and it would be just and reasonable to allow Centra to recover these amounts.

This will be a unique hearing, because in addition to the public portion of the hearing, the Board will have to review certainly commercially sensitive information in-camera. As such I will ask Mr. Hombach to provide his comments and explain the procedures to be followed over the next three days.

Mr. Hombach, bonjour.

MR. SVEN HOMBACH: Merci, M. President. Good morning, everyone. First of all, I'd like to second your congratulations to Mr. Rainkie on the new position. We're here to receive and test evidence with respect to Centra's 2015/'16 cost of gas application. And as you mentioned, this is an application that deals with Centra's gas transportation and distribution costs as opposed to the non-gas costs that usually are reviewed at a general rate application. In this case, the last general rate application was in the summer of 2013.

Now, to an extent, this hearing is also the continuance of an interim process that the Board instituted last fall to review an application by Centra to recover a substantial supplemental gas purchase variance account -- sorry, purchase gas variance account balance.

At that time, by way of Board Order 123/'14, the Board approved half of the balance to be recovered on an interim basis over a twelve (12) month period. Among other things, Centra is now applying to have the other half recovered.

In this application that is before you today Centra seeks approval of supplemental gas transportation and distribution rates effective November 1 of 2015, meaning the forward-looking ones, finalization of the interim purchase gas variance account order, and the recovery of the other purchase gas variance account balances that have accrued, including the 50 percent balance in the supplemental gas PGVA that I already mentioned, finalization of gas transportation and distribution rates previously in various interim orders, actual costs incurred, as well as finalization of a number of interim ex parte orders.

And as you alluded to, Mr. Chairman, the process to be followed in this hearing is somewhat new. In the past, cost of gas applications were fully public. However, due to a 2013 decision of the National Energy Board that granted TransCanada PipeLines full pricing discretion for interruptible and short-term firm transportation on the mainline which Centra has to use to bring gas to Manitoba, significant portions of Centra's evidence are now commercially sensitive as they could be used conceivably to price discriminate against the utility.

I'd remind you that Rule 13 of the Board's rules and practice and procedure does allow the Board to receive evidence in confidence where the release of such information could cause commercial harm to the utility or its ratepayers.

In this particular case, the Board has accepted the filing of portions of Centra's application in confidence under Rule 13. That means that the public version of the application and responses to Information Requests contain redactions.

The Board, however, as well as its advisors, have been provided with a full unredacted version, as has the Consumers' Association of Canada. The fact that the application contains commercially sensitive information makes it necessary to hold both a public hearing and in-camera hearing in this proceeding.

And I'd refer everyone to an outline of procedures that I've circulated this morning with extra copies on the little table by the door that explains the process. All of today has been set aside for the public portion of the hearing starting with Centra's direct examination, and then cross-examination by Board counsel and counsel for the Consumers' Association.

Tomorrow has been set aside for an in-camera hearing. Today, Mr. Rainkie has also graciously agreed to remain on the panel to answer any policy questions that the parties might have.

Now, during the session today members of the public are welcome to observe, and it's going to be a fully public process with transcripts being made available on the Board's website. However, tomorrow is going to be a closed hearing session with the doors locked and transcripts not being made publically available.

The Board's keeping an up-to-date exhibit list for this proceeding. And all the documents that have been filed to date have been entered as exhibits. Any parties who would like to file additional documents on the record are requested to canvass with associate secretary, Mr. Simonsen, so that the documents can be assigned exhibit numbers. And I'd like to remind the parties that there's only a single exhibit list despite a portion of the evidence being CSI. If a document contains CSI it can be identified as such, and it won't form part of the public record.

Any party that wishes to speak on the record during the public portion of the proceeding is reminded that, since it's public, all those documents will form part of the public record, and will be available on the website.

Now, with respect to Intervenors, Mr. Chairman, you alluded to there being two (2) registered Intervenors; the Consumers Association, represented by My Learned Friend, Mr. Meronek, as well as Just Energy. It's my understanding that only the Consumers Association intends to actually participate in this process, and the Board has not received indication that Just Energy will test evidence or file submissions.

The Consumers Association intends to adduce a witness, Mr. Mark Stauft, who is also here in the hearing room. Wednesday has been set aside for his evidence. And I anticipate that a portion of his evidence will have to take place in the closed in-camera session in the hearing room. However, we do anticipate some questions to be asked of Mr. Stauft on the public record, as well.

Currently, the Board has set aside October 5th for -- as a deadline for written closing submissions from Centra, and October -- sorry, October 5th has been set aside for written closing submission from CAC. October 9th has been set aside for written closing submissions from Centra. And the Board has set aside the evenings of October 6 and October 14 for oral evidence, if required. To date it's my understanding that that may work for the parties. If it does not work for the parties, they're certainly encouraged to speak on the record to see if the Board can otherwise accommodate them.

With that said, Mr. Chairman, I suggest that you call upon Mr. Meronek for CAC's opening comments, followed by Mr. Czarnecki to present Centra's opening comments. And we've agreed that the witnesses will be sworn after the concluding of opening comments. Thank you.

THE CHAIRPERSON: Masi, M. Hombach. Mr. Meronek, good morning.

OPENING COMMENTS BY CAC:

MR. BRIAN MERONEK: Good morning, Sir, members of the panel. I've never been called 'Learned Friend' in these proceedings before. I expect it's because I'm on this side of the room now, and I feel much more erudite. This is a different aura on this side.

In any event, I want to -- I've already thanked Mr. -- or, sorry, congratulated Mr. Rainkie off the record. I think on -- on line wouldn't be appropriate because of what I said. I do -- I was going to ask him on the public record how many residences he has and what perks he has, but I think I'll do that off line.

In any event, I have with me Mark Stauft, who is CAC's consultant who will be giving testimony on Wednesday. Gloria Desorcy, the executive director of CAC, told me that she was going to be here this morning. I don't see her as of yet, but she should show up.

There's a lot of material here, but we're focused primarily on a couple of issues. One is: We've presented evidence challenging, or questioning the reasonableness of what Centra did in the winter of 2013/'14, so we're going to be testing that both in direct and in cross. And we have recommendations with respect to the use of firm transportation going forward. So that will be our focus.

The -- there may be other things that we might be interested in but I'm not sure the extent to which we'll be cross-examining on the public record because I'm -- I'm a bit flummoxed as to what -- what's on the public record and what isn't. It's -- it's been daunting for me to -- to ascertain that. But in any event, I'll play that by ear.

In terms of -- I -- I -- my ears perked

up when Mr. Hombach indicated that Mr. Stauft might be asked questions on the public record. If that's the case, and I don't know what they would be, I -- I hope that that will be done on Wednesday. I hate to bifurcate what Mr. Stauft's evidence is going to be, so I -- I need clarification on that.

MR. SVEN HOMBACH: Just for clarity, Mr. Meronek, it would be the intention to do that on Wednesday, as well.

MR. BRIAN MERONEK: Thank you. And lastly with respect to oral argument, I indicated to -- if -- if necessary I indicated to Mr. Hombach, I'll be out of town on the 6th, but depending upon where I am I can always link in by a conference call. But I will be in transit between Edmonton and Calgary so I'd have to nail down a specific time so that I know that I can get to a phone and participate if necessary.

Those are my opening remarks. Thank you, Sir.

OPENING COMMENTS BY CENTRA:

MR. BRENT CZARNECKI: Good morning, Mr. Chairman, Member Kapitany, and Member Duboff. Perhaps to the Learned Friend comment from Mr. Meronek, maybe I can debunk this a little further.

Because not so long ago I was reading the Saturday morning newspaper before my children woke up and spoiled my quiet reading time. And I came across a picture of my Learned Friend, who had received a -- an award of winning the 2015 Benchmark Litigation of the Year award from -- from the Manitoba region. So as much fun as it is that Mr. Meronek has, it's a well-deserved Learned in front of Friend, and congratulations, Brian.

Second of all I, too, would like to congratulate Mr. Rainkie for stepping up and becoming the president -- acting president and CEO. And I think the Board knows that I'm very fond of now the late Yogi Berra and his Yogi-isms. And I think the one (1) that came to mind was when faced with a fork in the road, you take it. And we're happy that Mr. Rainkie take -- took it, and that he's here today and able to answer policy questions.

To start I would just like to introduce the panel that's up here with me today. Mr. -- to my immediate left, of course, the -- the familiar face to the Board of Mr. Rainkie, who is the acting president and CEO of Manitoba Hydro. To his left is Mr. Neil Kostick, who is a project leader with the gas supply division. Beside Mr. Kostick is Lori Stewart, who is the manager of gas supply, transportation, and storage department. To her left is Mr. Brent Sanderson, who is the manager, gas market analysis and administration department. And finally, anchoring the panel, is Mr. Greg Barnlund, who is the division manager for rates and regulatory affairs. And what I would suggest is if Mr. Simonsen can swear them in at this time. Then I'll proceed to introduce the back row, so you're familiar with their faces, and we can proceed accordingly.

CENTRA PANEL 1:

DARREN RAINKIE, Sworn
NEIL KOSTICK, Sworn
LORI STEWART, Sworn
BRENT SANDERSON, Sworn
GREG BARNLUND, Sworn

MR. BRENT CZARNECKI: Thank you, Mr Simonsen. Now, Mr. Chairman, just the back row introductions. First, starting right directly behind me, is Ashley Jansen, who is the regulatory services supervisor. Beside Ashley is Janelle Hammond, who is a second-year lawyer with the law department. Beside Janelle is Christine Foulkes, who is the senior gas supply operations analyst. Beside Christine is Terrill Sigurdson, who is the senior gas market analyst. Beside Terrill is Mr. Brad DeRyck, who is the cost allocation supervisor. And, last and not least, is Ms. Shannon Gregorashuk, who is the regulatory services department manager. All of which have had roles in supporting the materials that are before you, and will lend support to the witnesses as is necessary.

Now, prior to a -- a brief direct examination I, too, would like to echo some thanks to Board counsel, and Mr. Meronek, and the advisors who have cooperatively navigated this unique process that we're on. I think from Centra's perspective we would -- would certainly like, to as we have in the history, wanted to have this entire process publicly available. But as for the reasons noted by Mr. Hombach and as you'll hear more today, there has been a change such that part of the hearing must be conducted as commercially sensitive information.

And we do really appreciate the cooperative nature such that we are here today with a public -- with a public and a non-public part of the process, so we'll navigate accordingly.

EXAMINATION-IN-CHIEF BY MR. BRENT CZARNECKI:

MR. BRENT CZARNECKI: Now, Mr. Rainkie, I'll start with you. You are familiar with the application and the responses to the Information Requests and the evidence filed on behalf of Centra in this proceeding?

MR. DARREN RAINKIE: Good morning, Mr. Chairman, members of the Board, Intervenors and ladies and gen -- gentlemen present. My name is Darren Rainkie. I'm the acting president and chief executive officer and the vice-president of finance and regulatory and chief financial officer of Manitoba Hydro.

And I thank everybody for their kind words this morning. And I can assure Mr. Meronek that with my two (2) positions, the consumers of Manitoba are getting a very good deal. So rest assured, Mr. Meronek.

Yes, I'm familiar with the application responses to Information Requests evidence filed on behalf of Centra in this proceeding.

MR. BRENT CZARNECKI: And, Mr. Rainkie, was the evidence prepared under your direction and control?

MR. DARREN RAINKIE: Yes, it was.

MR. BRENT CZARNECKI: And can you confirm that, on behalf of the Corporation, you adopt the evidence that has been filed by Centra during the course of this process and that the panel members are going to be provided throughout this hearing?

MR. DARREN RAINKIE: Yes, I can.

MR. BRENT CZARNECKI: Mr. Rainkie, would you please outline your experience and qualifications for the Board?

MR. DARREN RAINKIE: Sure. I'm a chartered accountant, chartered business valuator, and have a bachelor of honours degree from the University of Manitoba. I've been with Manitoba Hydro and Centra Gas for over twenty-one (21) years.

And prior to my current positions, I've held various management and financial positions including manager of regulatory services, corporate treasurer, and corporate controller. I've held the position of vice-president finance and regulatory since January of 2013, and was appointed as chief financial officer in June of 2015.

On September 4, 2015, I was appointed as acting president and chief executive officer, and have retained my responsibilities as chief financial officer. I guess I have the longest business card in the Corporation now, Mr. Chairman.

I've testified before the Manitoba Public Utilities Board on numerous occasions, most recently during Manitoba Hydro's 2014/'15 and 2015/'16 General Rate Application held in May and June of 2015.

In my testimony, I will provide evidence on policy matters as they relate to Centra's 2015/'16 cost-of-gas application.

MR. BRENT CZARNECKI: Thank you, Mr. Rainkie. Mr. Kostick, over to you. Would you please outline your experience and qualifications to the Board, please.

MR. NEIL KOSTICK: Thank you. Good morning, Mr. Chairman, members of the Board, ladies and gentlemen. My name is Neil Kostick, and I work in Manitoba Hydro's gas supply division as project leader, which is the position I've held since 2010.

My responsibilities are mostly related to medium- to longer-term supply arrangements such as Centra's western Canadian supply contract. I also led a project team that evaluated storage and transportation options prior to the expiry of Centra's original twenty (20) year contracts with ANR and Great Lakes, ultimately resulting in the current seven (7) year arrangement.

More recently, I led the Company's efforts to execute Centra's first natural gas liquids extraction contract.

Prior to my current role, I served as the manager of the gas supply, transportation, and storage department on an interim basis for just over a year starting in 2009. I also served as a departments storage and transportation specialist from 2007 to 2009.

I completed a bachelor of commerce honours degree in 1998, graduating with distinction, and an MBA degree in 2005, both from the University of Manitoba.

I've been employed by Manitoba Hydro since 2001.

I've appeared before the PUB on behalf of Centra Gas on three (3) previous occasions, most recently at the 2012 transportation and storage portfolio hearing. I've appeared as a witness for Centra before the National Energy Board on two (2) occasions in 2013 and 2014.

MR. BRENT CZARNECKI: Thank you, Mr. Kostick.

Ms. Stewart, would you please outline your experience and qualifications for the Board?

MS. LORI STEWART: Good morning, panel. I manage the operation and optimization of Centra's asset portfolio. My formal title is manager of gas supply, transportation, and storage department.

I've been employed by Manitoba Hydro or Centra Gas Manitoba and its predecessor companies for twenty-seven (27) years. I became a manager in the gas supply division of Manitoba Hydro in June of 2002 and assumed my current role in November of 2006.

I've testified before the Public Utilities Board of Manitoba on numerous occasions, most recently, at the 2013/'14 general rate application in June of 2013. I have also managed Centra's cases in each of the recent TransCanada proceedings before the National Energy Board starting with the RH-3 2011 proceeding in the summer and fall of 2012, the RH-1 2013 proceeding in the fall of 2013, and the RH-1 2014 proceeding in the fall of 2014. I testified before the NEB in each of the aforementioned proceedings on behalf of Centra and its ratepayers.

I'm a long-term member of the Mainline Tolls Task Force Industry Group. I also oversee Centra's participation in the American Gas Association's FERC regulatory committee, FERC being the Federal Energy Regulatory Commission in the United

States which is of interest to Centra given our US asset portfolio.

I'm responsible for the activities underlying the gas costs incurred in all of the gas years addressed in our application, including Centra's gas supply, transportation, and storage portfolio, changes to the portfolio since the 2013/'14 general rate application, Centra's Capacity Management Program, and TCPL and related matters. Thank you.

MR. BRENT CZARNECKI: Mr. Sanderson, over to you. Would you please outline your experience and qualifications for the Board?

MR. BRENT SANDERSON: Good morning, members of the Board. My name is Brent Sanderson. And I've been employed by both Centra Gas Manitoba and Manitoba Hydro in various roles for more than twenty (20) years. I first joined Centra Gas in 1994. And at the time, I was engaged in conducting activity-based costing studies as well as the development of activity-based costing models.

In 1995, I joined Centra's load forecasting department as a load forecasting and research analyst. In this role, I was responsible for the development of the Corporation's daily, month, and annual natural gas load forecasts, conducting load research studies, carrying out the Company's gross margin function -- pardon me, gross margin accounting function, as well as the development of new rate design alternatives in response to natural gas industry unbundling at the time, such as the currently approved variable quarterly primary gas rate adjustment mechanism.

In 2000, I accepted a position in Manitoba Hydro's Gas Supply Division as the senior gas cost and hedging analyst. During my tenure in this position I conducted energy market research, developed the Company's annual purchase gas cost forecast, managed Centra's various purchase gas cost deferral accounts, research, developed, implemented, and executed Centra's commodity risk management programs as well as developing proposals for alternative retail natural gas product offerings, such as the fixed primary gas service.

In 2006, I assumed the po -- my current position as manager of the Gas Market Analysis and Administration Department in the Gas Supply Division of Manitoba Hydro. Since that time, I have been responsible for leading the functions for which I was responsible in my immediately preceding role, as well as the direct purchase function which is charged with facilitating the direct sale of primary gas to end-use customers by third party marketers in Manitoba.

I completed my Bachelor of Administration degree with great distinction from Athabasca University in 2004. And in 2012, I earned the professional designation of certified energy risk professional. I am a member of the Global Association of Risk Professionals and have appeared as a witness on behalf of Centra Gas and Manitoba Hydro before the Public Utilities Board of Manitoba on numerous occasions over the past fifteen (15) years.

In addition, I was al -- I have also represented the interests of Centra and Manitoba natural gas customers as a witness before the National Energy Board of Canada. Thank you.

MR. BRENT CZARNECKI: Thank you, Mr. Sanderson. Mr. Barnlund, would you please outline your experience and qualifications for the Board?

MR. GREG BARNLUND: Yes. Thank you, Mr. Czarnecki. Good morning, Board chairman, Board members, representatives of the CAC, and ladies and gentlemen in attendance. My name is Greg Barnlund. And I'm the division manager of rates and regulatory affairs in the finance and regulatory business unit here at Manitoba Hydro.

I graduated from Red River Community College in 1988 with a diploma in mechanical engineering tech -- technology, and I am certified as an engineering technologist in Manitoba. I began my utility career at Inter-City Gas, predecessor to Centra Gas, in 1989. And so I've been in the utility industry for some twenty-six (26) years.

I was appointed to the role of division manager for rates and regulatory affairs in June of 2013. Prior to that, I held various positions throughout the organization with regards to regulatory affairs, gas supply, rates, customer policy, service extension policy, and industrial marketing and sales.

My current responsibilities include overseeing the preparation of Rate Applications and regulatory filings before the Public Utilities Board, and for regulatory compliance matters before the National Energy Board with regards to our Minell pipeline subsidiary. Our division also prepares rates and cost of service studies for both electric and natural gas operations, and we also administer business investment policy for electric operations.

I first testified before the Public Utilities Board in 1996, and I've had the opportunity to testify here on several occasions. I've also appeared before the National Energy Board, and the Federal Competition Tribunal. In my career, I've testified to matters related to rates and rate design, cost allocation, terms of service, service extension policy, matters related to the competitive landscape for natural gas sales here in Manitoba, and to the development of western transportation service.

Most recently, I testified before this Board in the springtime with regards to Manitoba Hydro's 2014/'15 and 2015/'16 General Rate Application with respect to electricity rates. In this Application, I'm providing evidence on our natural gas rates and on the approvals being sought, and other related matters with respect to this Application.

MR. BRENT CZARNECKI: Thank you, Mr. Barnlund. Mr. Chairman, just one more introduction. I see Mr. Lloyd Kuczek, for the reporter it's K-U-C-Z-E-K, is in the gallery, and I just wanted to acknowledge his attendance. He is the vice-president of customer care and energy conservation. All of the three (3) gas supply in the middle report to Lloyd, so he is a keen observer today, as well.

We are, Mr. Chairman, prepared to commence with our direct evidence presentation, and I for -- understand from Mr. Simonsen it should be marked as Exhibit Centra-16. So we are in your hands as to when you want to proceed.

--- EXHIBIT NO. CENTRA-16: Direct evidence of Centra Gas

MS. MARILYN KAPITANY: I just have question. If either Mr. Czarnecki or Mr. Rainkie, or you may just have answered my question, but I hear all of the people here saying what parts they have in gas.

Can you just tell me: Who would have overall responsibility for a decision related to something in Centra Gas?

MR. DARREN RAINKIE: Ms. Kapitany, the gas side of the business is fully integrated with the electric side of the business, so all of the executive members of Manitoba Hydro are also executive members of Centra Gas. So the functional responsibility for gas supply reports to Mr. Kuczek, and -- and -- but it's the same executive committee that would review significant proposals, and -- and approve those proposals.

MS. MARILYN KAPITANY: So it would be Mr. Kuczek then that would take the -- the various roles that we've just heard about here, bring them all together, and then talk about them with the executive team?

MR. DARREN RAINKIE: That's correct, as well as the Board as well, based on our approval levels for what has to go to the executive committee and the Board.

MS. MARILYN KAPITANY: Thank you.

MR. DARREN RAINKIE: Good morning again, Mr. Chairman. I see that at least the monitors are working on this side, and the big red button is lite so I assume everybody has our presentation in front of them, and we can commence.

So Centra is pleased to appear before the Public Utilities Board today in support of its 2015/'16 Cost of Gas Rate Application. As a public utility, Centra believes that it is essential to clearly explain the need for rate changes to the Public Utilities Board, stakeholders, and customers. This public process is an important part of that communication process.

In this Rate Application, Centra is requesting approval of changes to its supplemental gas transportation and distribution rates to be effective November 1st, 2015. Centra is not applying to change its primary gas rates at this point in time. Centra will file a Primary Gas Rate Application around the middle of October, as is the normal course, for implementation on November 1st, 2015. And we'll file combined rate impacts with the PUB at that point in time. Centra is not applying to change its non-gas costs in this application. That is accomplished through periodic general rate applications, as the financial circumstances dictate.

So, Mr. Chairman, my portion of the presentation this morning will be uncharacteristically short. The circumstances that underpin this rate application are very technical in nature, to say the least. But as a policy witness on the panel, I did want to provide a brief overview of the corporate perspective on this application and the circumstances that bring us before the PUB today.

As was the case with the recent electric general rate application, we think that it's important to start at the strategic level by considering Centra's mandate, which we've outlined on the chart in front of us. Which is to require, manage, and distribute supplies of natural gas to serve Manitobans in a safe, reliable, cost-effective, and environmentally appropriate manner.

Providing natural gas service to

Manitoba customers not only involves managing costs, but most importantly, ensuring safe and reliable service. In the absence of safe and reliable service of an essential commodity such as natural gas, rates become a moot point. Centra takes all aspects of its mandate seriously, and by necessity needs to balance all of the objectives that you see on the chart to provide value to its customers.

It is within this context that Centra makes decisions on behalf of customers as they relate to customer service, gas supply, and rates. We believe that these objectives are also important considerations for the Public Utilities Board with the respect to the rate-setting process. We are confident that the evidence that Centra witnesses will provide over the next few days will demonstrate that Centra has been very successful in fulfilling this mandate during the gas years that are under examination at this rate proceeding.

This success will be demonstrated in three (3) key ways. First, Centra has a reliable, cost-effective portfolio of assets to ensure security of supply, and to provide diversity to manage risks. For reasons that will be elaborated on later in the presentation, the characteristics of the Manitoba natural gas market, and our geographic location, make it an inherently challenging market to serve.

As such, Centra takes a long-term perspective in developing its gas supply strategies, in order to reliably and cost-effectively serve Manitoba customers over a wide range of conditions that may be experienced. A significant portion of the costs in this rate application relate to the extremely challenging weather and market circumstances in the winter of 2013/'14. Centra's gas supply portfolio successfully met these challenges on behalf of customers in very difficult circumstances.

Second, Centra has a very experienced gas supply procurement staff that have skilfully and successfully maintained reliable operations to serve the Manitoba market under extreme conditions. As you can see from the qualifications and experience of the group of gas supply professionals present here today, both in the front row and the back row, Centra is indeed fortunate to have staff with such a deep understanding of the natural gas industry in general, and the Manitoba market that they serve in particular.

Most importantly, I'm confident that after the next few hearing days the PUB will understand what we already know to be true in the

Corporation, that these gas supply professionals have the capability to successfully design a gas supply portfolio and execute operational strategies to meet the challenges of the Manitoba market, and deliver on Centra's mandate of providing safe and reliable service three hundred and sixty-five (365) days a year.

Third, gas rates in Manitoba are set based on a reasonable, flexible, consistent, and well established reg -- regulatory framework, which benefits Centra's customers. Centra and the Public Utilities Board use a gas cost pass-through rate-setting framework that is universally accepted by gas distribution utilities and regulatory bodies in North America. It's a proven approach that appropriately balances risk between Centra and its customers, and ensures rate stability and the lowest cost to customers over the long run.

It has worked well for Manitoba natural gas ratepayers for decades, and has demonstrated the flexibility to appropriately deal with circumstances such as the extreme weather of 2013/'14 in order to smooth rate impacts for customers.

The resulting customer bill impacts are modest and reasonable when considering the stream --

extreme weather conditions and unusual market circumstances that Centra faced in 2013/'14.

So those will be the three (3) key themes I think that run through this application, sir, when we look at this as a -- on a strategic perspective.

So on an overall basis, when placed in the appropriate context, the circumstances that underpin this rate application are actually a good news story for Manitoba natural gas customers. Centra was able to meet the firm requirements of Manitoba customers on some -- under some of the most challenging and extreme conditions.

We have been able to work with the Public Utilities Board and Intervenors over the last number of months to find an approach to recover the associated gas costs that has smoothed the rate impact out to customers.

Centra has fulfilled its mandate and continues to provide valuable service to customers, and as such it is appropriate that the PUB allow full recovery of the 2012/'13, 2013/'14, and 2014/'15 gas costs embedded in this rate application, and that we bring a close to these matters so that we can move forward and focus on the challenges that lie ahead in the 2015/'16 gas year and beyond.

So, Mr. Chairman, with those brief opening comments, in a few seconds I will turn it over to the rest of the panel to go through the remainder of the presentation. Just to give you some way finding on what we're going to do this morning, Ms. Stewart will describe the challenges in serving the Manitoba market and how Centra's gas supply portfolio and operational strategies have and will continue to be successful at beating these challenges.

Mr. Sanderson will provide further detail on the gas cost deferral balances and the 2015/'16 gas costs forecast that form part of this rate application, and will provide further context on how PGVAs have been used in the past to successfully smooth out rate impacts to customers.

Mr. Bardlund will outline the requested approvals in the application and Centra's approach to recovery of the gas costs and associated customer bill impacts.

And I should have said at the outset, Mr. Chairman, that this hearing is here obviously to inform the Board on the particulars around this rate application. So at any point during the presentation, we would encourage Board members to stop and ask questions. You don't have to save them up to the end or anything like that. That's -- the purpose of the presentation is to have a dialogue back and forth so that there's good understanding. So we encourage the Board to ask as many questions as they can.

THE CHAIRPERSON: Mr. Rainkie, at the outset of your presentation, you mentioned some dates for submissions. Could you repeat those dates for the -- the cost of gas? Right at the outset you said, This is the time line for your applications, please, if you don't mind, please.

MR. DARREN RAINKIE: Yes, Sir. I was just wanting to make sure it was clear in the Board's mind that this application is with respect to what we call non-primary gas costs. It's unfortunate we have to describe things in the negative, but that's the way it goes.

So -- and there are other -- other -- two (2) other pieces to the rates that we charge Manitobans. One is primary gas costs, and of course that's a separate process that's done on a -- on an interim basis.

And we would expect to file, as we normally do, a November 1st Primary Gas Rate Application towards the middle of October. And when we do that, we'll take the rate impacts from this application plus the rate -- the rate impacts from the Primary Gas Rate Application and combine them so that the Board knows what the -- what the total impact is.

And, sir, if there are no further questions, I'll -- I'll be here as long as the Board requires me to be here. I'll pass it on to Ms. Stewart if that's the case.

MS. LORI STEWART: Good morning again. I'll walk the panel through a high-level summary of our gas supply, transportation, and storage arrangements, as well as the environment within which we operate. And we will of course get into our arrangements in much more detail tomorrow in the CSI portion of the proceeding.

In gas supply, we internalize Centra's mandate as serve the load; that's what all of our activities are geared around, with the four (4) planks, safe, reliable, cost-effective, and environmentally appropriate.

A summary of our key gas portfolio activities starts with long-term portfolio planning. And as -- as members Gosselin and Kapitany are aware, our US transportation and storage portfolio concludes in 2020. And our team is already mapping out the potential implications that we may encounter in the post-2020 time frame. And that's an activity that Mr. Kostick and myself, as well as the members of our broader team, are -- are engaged in.

Contract negotiation and execution. Everything from our enabling contracts, the industry standard NAESB contract, which is the -- the standard North American Standards Board format, and it defines a number of commitments that the parties are making to one another contractually to our longer-term portfolio arrangements, our mid-term western Canada supply arrangements, our seasonal or monthly contracts that we enter into, as well as daily confirmations.

And our supply planning and operations functions in a number of different time windows. Everything as -- it ranges from everything to inter-day, so once a gas day has commenced we have currently two (2) opportunities to alter our call or nominations for gas, to daily to weekend to monthly to seasonal, and then our annual contracts.

And we're operating within our contractual limitations. It's critical that our traders and schedulers are always aware of what those contractual limitations are and that we're situationally aware that we are monitoring on a daily basis any critical notices that may be issued by the pipelines on which we move natural gas. That we're also aware of potential regulatory developments, so situationally aware in the broadest sense.

Another key portfolio activity is, once we've assured ourselves that the load will be met, we then move into efforts to mitigate the costs of our fixed transportation arrangements. And that's referred to as our Capacity Management Program. I may refer to it as our optimization activities.

And it is important to understand our mind set as it relates to optimization because optimization of our assets is never pursued until we've first assured ourselves that we can serve the load. If there are excess assets after that, after we've provided for the buffer we need to accommodate alterations or variability in weather, then we will move into optimization activities.

Regulatory monitoring and intervention has -- the workload associated with that has increased significantly given the challenges that the TransCanada mainline has faced over recent years. And as well, there are -- I mentioned earlier there are regulatory developments that we need to be aware of that are occurring at the FERC level. For example, we are moving into a new world that includes an additional inter-day nomination window effective April the 1st, 2016. And the genesis of that was FERC's mandate to better coordinate the gas and electric industries as a result of the increased reliance in electricity production on gas fired generation, and that's a phenomenon that is occurring across North America.

I mentioned Centra's interventions in each of TransCanada's three (3) major proceedings before the National Energy Board. Centra filed evidence in each of those proceedings. It produced witnesses, and we submitted written or oral final argument.

And the last key gas portfolio activity, which again continues to grow in terms of the effort that we need in order to ensure compliance are all of the authorizations and permits that we must hold, as well as the reporting obligations that accompany those permits.

Given that our asset portfolio spans both Canada and the United States, we have export and import authorizations that we need to ensure are in place with both the National Energy Board as well as the Department of Energy in the United States. Given our liquids extraction arrangement, we now as well are permitted by the Alberta Energy Regulator in terms of exports.

And we provide monthly reporting to the National Energy Board, the Department -- the Department of Energy, the Alberta Energy Regulator, the Federal Energy Regulatory Commission, as well as US customs and border protection in terms of our movement across the US border.

MS. MARILYN KAPITANY: Ms. Stewart, could you just say briefly, you mentioned the new FERC regulation that's coming in place on April 1st, 2016. What if any implications will that have for the cost of gas as it relates to this hearing?

MS. LORI STEWART: From a -- from a dollar perspective, it is likely that the workdays of our traders and schedules will need to shift in order to accommodate what is a later nomination window intra-day.

But from -- from a cost perspective in terms of not the operation cost but the actual assets that -- that are in place, we're not anticipating any cost impacts associated with assets. It's more a function of, How do we re-work our operations to ensure access to that third intra-day nomination window.

(BRIEF PAUSE)

MS. LORI STEWART: Mr. Rainkie mentioned that I will walk though the challenges in serving the Manitoba market, and we'll start with weather.

Weather in Manitoba is both extreme, as we're all well aware, as well as variable. And it is variable in all of the time windows within which we're required to operate. Weather in Manitoba is more uncertain, and more volatile than the weather in any of the other major markets served by TransCanada.

You see that the steepest load curve is represented by the red bar in this chart, and the red bar is Manitoba followed closely thereafter by Saskatchewan. Manitoba has the highest degree of seasonal variation in heating requirements due to seasonal weather patterns. We also experience the greatest uncertainty in terms of weather, both on an annual as well as a daily basis.

This next table shows total annual heating degree days for Manitoba, and a variety of other market regions served by TransCanada for a normal year, as well as for the warmest year and a coldest year. Manitoba weather exhibits both the largest absolute amount of spread in traditional heating degree days, as well as the largest relative range in traditional heating degree days.

In terms of our operations and supply planning requirements, day-to-day volatility in demand is actually more important than annual uncertainty. Our planning must account for changes in day-to-day weather to ensure that the proper volume of gas is available to meet demand, so that the utility is not generating pipeline imbalance fees; and so that we're operating as a responsible shipper on the pipelines on which we move gas.

MR. NEIL DUBOFF: Ms. Stewart, when you get information for -- for weather, how far into the future does your forecasting go?

MS. LORI STEWART: On a daily basis we're looking at -- typically we're looking at three (3) forecasts, and assessing the degree of consensus amongst the forecasters. We like to see consensus, but unfortunately that is not always the case. And so that's, in the short-term, what we're assessing as well as going back into our databank of history, which allows us to try to replicate the day that is being forecast.

Around things like the degree of cloud cover can significantly influence the extent to which effective heating degree days can occur. What is the wind chill that's forecast? So there are a number of -- of factors that our schedulers and load forecasters are looking at in the short-term. We do -- we do assess longer term forecasts, but the extent to which we rely on them is reduced, the greater out in time that the forecast is related to.

MR. NEIL DUBOFF: Do you -- what -- what range do you get your -- your forecasts for? A day in the future, a week in the future, a month, a year?

MS. LORI STEWART: The -- the forecasts that we look at in the long-term will be, for example, we have access today to forecasts that are outlooking the upcoming winter. So that would be generally the extent to which we will have a long-term forecast, will be for the winter ahead.

MR. NEIL DUBOFF: Do you -- what's the reliability of those? Do -- do you have -- do you have statistics, or -- on -- on the reliability of the forecasts you're getting in the short, medium, and longer term?

MS. LORI STEWART: I would suggest that the reliability is very questionable for long-term forecasts. An example of that the long-term forecasters, heading into 2013/'14 winter, their forecast was for a normal winter. So the -- the long-term forecasts are wrong a far greater percentage than they're right.

MR. NEIL DUBOFF: So -- so I -- I hear you that they were wrong in that year, because they -- they said it was going to be a normal year and, in -- in fact, it wasn't.

But in general, with the statistics that you're getting, how reliable have they been? We know that year they were off, but how much can you rely upon it? So when you're getting forecasting, and you're buying gas, how much are you able to rely on what the forecasters are telling you?

MS. LORI STEWART: The -- well, in the long-term we're always planning for the range of potential market requirements that -- that our historical data in -- informs us of, as well as using an optimization model to generate random weather outlooks, or scenarios that may occur. So in the long-term we cannot rely on a weather forecast to plan this winter.

What we have to do is plan for the potential range of market requirements that we expect could be experienced in the shorter term. So if we're looking at today's forecast for tomorrow, then certainly as we close in time to something in the very immediate term, the -- the degree of confidence around the forecast improves significantly.

THE CHAIRPERSON: So let's -- let's take that back now to a situation where, you know, you're -- you're looking at the winter. It's supposed to be a normal winter. November, you've locked in your supply stack for November, and all of a sudden you start seeing the weather changing.

So what's your reaction? You're sort of seeing -- well, the forecast is not being realized. It's getting a lot colder than we expected. Then what? What do you do?

MS. LORI STEWART: We will already be positioned to serve the potential range of market requirements that could be experienced. We cannot rely on a forecast of winter which is a long-term weather forecast. We cannot rely on that to design our portfolio.

Our portfolio design is premised on what is the actual range of weather that we may experience. And we're planned to serve the coldest, and we're also planned to serve the warmest.

THE CHAIRPERSON: Okay. So you couldn't predict -- you didn't predict the -- the '13/'14 weather based on what you just said, couldn't tell because they'd forecasted normal.

So we start the -- start the -- start into November, and then we get a very cold December, extremely cold December, which was beyond your model expected range, if I understand you correctly.

Had you predicted -- had you predicted the very cold winter? I mean, you -- you said you -- you established the supply based on the range that you would expect. So if we get a winter that's beyond the range -- tell me if I'm wrong or I'm -- correct me if I'm not -- I'm not right.

(BRIEF PAUSE)

MS. LORI STEWART: It sounds like you're seeking to understand, as actual weather starts to be realized within a winter time frame, how do we respond to that.

And so as we -- as we move forward within winter, we've got a -- a one hundred and fifty-one (151) day winter season where we have access to storage. And each day that transpires, it expires under us, we see what our storage pulls were, we're -- we're monitoring the extent to which winter is being realized relative to normal.

That's the forecast that Mr. Sanderson's team prepares. In the real world, however, we're prepared to serve the -- the range of extremes around that normal forecast.

And as far as how winter may be unfolding, even into the end of November and the end of December, the potential range in the remaining extent of winter, we've still got three (3) months out of five (5) left in our winter season.

And we've seen occasions where the rest of winter can simply disappear. You may have a cold November, a cold December, and then winter in essence has gone away. And as a result, then we're set -- set up to -- to address that scenario.

The scenario in 2013/'14 was one where there -- first of all, it was third coldest winter experience within Manitoba in the fifty-five (55) years of -- of history that we have on file.

So within our weather records, we were already set up and positioned to respond to winters that were colder than what we experienced in 2013/'14. There's no doubt it was an extreme occurrence, and it was the coldest winter in North America in thirty-two (32) years of recorded history.

And so that starts to have the knock-on effects when the entire continent is cold in terms of continental demand for natural gas, continental storage inventories, and the -- and the way those start to effect commodity prices when we're in an extraordinarily high-demand scenario.

But within -- but within Manitoba, we have occasions that are colder marginally than 2013/'14, and they're embedded in our models that are -- are pushing us to design to the potential range.

That's -- in operations, on the physical side of the business, Mr. Sanderson's normal year forecast is of interest. But as soon as we're stepping into the real world we have to be prepared to serve the range. Does -- does that help you?

THE CHAIRPERSON: Yes, it does help me. I think I heard you say that the range you -- we -- the range we experienced you had predicted -- you had planned for, the range of weather that we experienced during that winter you had planned for prior to the winter.

And so you -- the range that you planned for was well within the experience that we lived during that winter?

MS. LORI STEWART: Yes, we had planned for within our planning the experience of 2013/'14 in terms of seasonal requirement for natural gas was within our models.

THE CHAIRPERSON: So the followup question then becomes: If it was within your model, you would have had plenty of gas to deal with the weather?

MS. LORI STEWART: And -- and we did have sufficient natural gas to -- to serve our load throughout 2013/'14.

MS. MARILYN KAPITANY: And, Ms. Stewart, you said that there was a hundred and fifty-one (151) days worth of storage, and so that would have been the case in the winter of '13/'14. And was that storage completely -- access completely used during that winter?

MS. LORI STEWART: Yes, we very actively managed our storage inventory levels throughout the winter of 2013/'14. What we want to do is ensure that we have access to our maximum daily deliverability out of storage. We're wanting to

extend the time to which we have access to that
maximum daily deliverability.
We're also wanting to ensure that we
don't churn through our storage inventory in the first
half of the winter such that we're set with no access
to storage during the latter part of the winter as it
unfolds.
So we actively manage our storage
inventory levels every year. And we actually withdrew
our last molecule of gas out of storage on the one
hundred and fifty-first (151st) day of winter, on
March 31st.
MR. NEIL DUBOFF: So -- so I guess
where I'm getting confused, and maybe this will come
out in the next couple of days, is, to the extent that
it appeared an -- an aberrant year statistically
weather wise, and you say it was planned for and we
had the storage for it, then why did the result turn
out so different? Why did the result in terms of the
bottom line for Centra Gas turn out so different and
we're even talking about recovering on -- on a loss?
MS. LORI STEWART: At the most basic
level, we are in the market buying supplemental gas.
And supplemental gas purchases, the number of millions
of GJs of supplemental gas that we may be purchasing

given the potential range and annual requirement of our market is significant.

So the first driver was weather was causing us to purchase far more gigajoules of gas. But most importantly, the -- the difference between the price paid for those molecules of gas relative to forecast result in a deferral balance.

And I just described the fact that in North America it was the coldest winter in thirty-two (32) years, and as a result, you have the entire North American market chasing the marginal molecule of natural gas. We are in an extraordinarily high-demand scenario. And some of Centra's purchases -- I mean, we are a swing market. They cannot be base loaded into our market because, in large part, we would -- we would be exposed to significant take or pay obligations.

So we are buying based on a daily index, not a monthly index. We're a swing market. And as a result, we're in the market buying spot gas ju -- along with everyone else.

MR. NEIL DUBOFF: And what you've just described is what I understood -- the latter comments is what I understood was going on. You had to buy it in the marketplace. The marketplace was changing because of North American demands. That's what I understood.

But your comment that -- that you did plan for it, there was plenty of supply, I'm a little confused on that because to the extent that you planned for it -- to the extent that I understood there's plenty of supply and you -- and -- and you planned for the abhorrent weather, how could it have been off?

MS. LORI STEWART: The -- the difference is between planning the assets to get the commodity to your market. So we have to ensure that we have assets in place, given our reliability mandate, in order to move commodity. Commodity is not produced here in Manitoba. It's produced afar. We're buying out of a number of supply hubs. We're buying out of Alberta. We may be buying commodity in Michigan and Chicago.

So when I talk about needing to plan for the range of potential market requirements that will be experienced, that means having assets in place to meet your peak day, your peak season, or conversely an extraordinarily warm scenario where we still are positioned to serve the warmest or to serve the coldest.

MR. NEIL DUBOFF: The -- the --

MS. LORI STEWART: But in terms of actually buying commodity, we cannot escape some exposure to daily spot markets given that we're a swing market. Heading into the winter, Centra doesn't know whether it's going to end up consuming its all time low forecast of natural gas, or its all time high. So --

MR. NEIL DUBOFF: But -- but reliability has two (2) elements to it. There's -- and -- and that's one (1) of the four (4) pillars. Reliability has -- has a side of supply, but it has a supply of cost. And what I'm hearing is that you -- a lot of work is put into reliability on the supply side, but how do we deal with reliability of costs?

Because what you've said is you've -- you've anticipated the range of weather which means that you're going to have enough supply for that range, but what about the range on the cost side? Like -- because that's a variable, too, according to the markets.

MS. LORI STEWART: When we model our portfolio, there are outlier years within our model results. Given the range of weather in Manitoba, there is no escaping unless you're going to contract on an annual basis for commodity as well as assets in order to secure your price as well as your transportation path to your market.

We could do that, but the structural increase in our annual costs would be significant --

MR. NEIL DUBOFF: Can you speak to that?

MS. LORI STEWART: -- and in --

MR. NEIL DUBOFF: Can you speak to that? What does that mean? The annual cost in stru -- what -- what would be -- how would that come about?

MS. LORI STEWART: So one way to protect access -- for example the suggestion is: How can we secure the price of the commodity paid? Well, even hedging can't solve that problem for us because you can't hedge a swing supply. You can only hedge an amount that you're saying, I'm going -- I'm certain that I will need this amount of gas coming to my market.

That portion of your supply you could use a financial instrument to hedge the price. However, that's not where -- where you from time to time experience increases from in -- from a commodity perspective. It's around the daily purchase in a spot market in a high-demand scenario.

And how could you go about that? I guess you could structure firm annual assets at the level of your peak.

MR. NEIL DUBOFF: M-hm.

MS. LORI STEWART: And you could move baseload, or take or pay levels, to your market at tho -- that commodity would come into your market every day, and in most days you would be selling gas because you're long and you would be selling at a loss.

THE CHAIRPERSON: So I just want to make sure. Leaving aside the -- the issue around price, I -- you know, I'm trying to understand the supply situation you're in.

So you -- you've planned for the -- you've planned for the worst, obviously, but you have to go in and buy the gas to address the peaks. Is that -- is that what causes you to go into the marketplace when you know you have enough supply of -- to last you the winter?

Would -- would -- there's a disconnect in our minds between why you're buying gas in the marketplace when you -- you said at the outset you've got plenty of supply.

So can you explain that piece to us?

MS. LORI STEWART: I'm going to

advance forward, and -- and demonstrate using a visual.

THE CHAIRPERSON: Okay. That would be great.

MS. LORI STEWART: Okay?

THE CHAIRPERSON: Yeah.

MS. LORI STEWART: I'll come back to where I am in the presentation. Oh, here it is. It's up next. So this visual is -- is meant to demonstrate the -- the load factor that is experienced. And we -- we haven't talked about that yet, but for the record, load factor meaning the percentage ratio of average load to peak load. And in Manitoba given that we're predominantly space heating, and we're extraordinarily weather dependent, we have a very low sales load factor. The load factor at which natural gas is consumed within our market is only 34 percent.

And this is an important relationship between when -- when we talk about load factor, because the higher the load factor the lower the unit cost of transportation. So if I was serving a market that had a processing load, it was a market of a single large industrial plant like Koch in -- a fertilizer company in Brandon, where day in day out Koch burns a certain volume of natural gas. And they're using it for processing. They're not really subject to heating variation. Then their load factor would be very close to 100 percent. The only reason for variation around that would be because of a plant disruption on the day. So their load for -- factor might -- might wend down a -- a wee bit from there.

Centra's sales load factor of the market that it's serving, that 34 percent, you see that represented in the solid red line. So that's our typical overall average Manitoba sales consumption load factor given a normal year. But the dotted lines around it are the range of experience that Centra must be positioned to serve. And remember that relationship where the lower the load factor you're serving, the higher the unit cost of your transportation.

So what Centra does is in an effort to strive that theoretical perfect world of a 100 percent load factor, we're layering in assets that allow us to improve our sales load factor to the degree possible. And we're able to -- and this is a twenty-two (22) year history that Mr. Sanderson's prepared -- we're able to shift our 34 percent sales load factor up to 70 percent. And that's the -- the blue line that you're looking at there.

So you see how the actions that we're taking with our asset portfolio are designed to smooth out that extreme load curve from a transportation perspective. And we're positioned in the commodity markets to -- we've got -- we've got access to a number of -- of hubs, but when we're -- we look at that red line and you see the variation there in terms of natural gas being consumed, you can imagine the challenge with -- with committing in advance to what level of commodity will be used in the marketplace. We are a swing market. It's a function of weather. It's a function of a space heating load, and we can't alter that.

MS. MARILYN KAPITANY: Could you just say again what the steps are that you take, or how you move from that 34 percent to a 70 percent that you just referenced?

MS. LORI STEWART: The -- the number 1 contributor to our ability to improve that purchase load factor, and increase it from 34 percent to 70 percent, is contracting for storage.

So storage is what allows us to -- in summer months, when the market is using very little natural gas, it allows us to flow more units of commodity through our -- what -- our otherwise empty transportation capacity. And we flow commodity on that path into storage during all seven (7) of our -- our summer months.

So that improves the amount of units that are flowing through your pipeline all summer, and it also improves the extent of transportation capacity that we would need to serve our peak day because we're able to pull gas out of storage in order to meet the peak.

And, you know, a peak day, roughly you can think of it as -- as a half a million units. And storage is contributing on a daily basis 40 percent of that during the winter months, a little more than 40 percent, two hundred and fifteen thousand (215,000) out of roughly five hundred thousand (500,000) units.

So storage is the -- the number one driver for -- that allows us to improve our purchase load factor relative to what our market is without that activity.

MS. MARILYN KAPITANY: And are there other factors? Are there other steps that you take to improve that percentage? And if any of this is CSI, just let me know.

MS. LORI STEWART: I -- I think I would have to -- it starts to get into the strategies that we deploy. So I'd prefer to -- to wait on that until tomorrow.

THE CHAIRPERSON: So in general terms, if you -- oh, go ahead. Are you done?

MS. MARILYN KAPITANY: I was just going to ask -- I was also going to ask you about risk mitigation. There must be a risk mitigation strategy that you have in place.

And, Mr. Sanderson, maybe this is more your area, but there must be a risk assessment that you do around this and then mitigation strategies that you put in place. And I'm wondering if you're going to be talking about that today, or if that is again CSI that we'll be hearing about.

MS. LORI STEWART: What will follow in my presentation are both high-level portfolio strategies as well as operational strategies. So I think, at the level at which we can converse about those topics, we're about to -- to get into those. If you could see whether or not, after I've walked through those, whether your question is addressed.

MS. MARILYN KAPITANY: If we ever let you get there.

MS. LORI STEWART: Okay.

THE CHAIRPERSON: But -- but that's

speaking in general terms. Let's look at that -- let's look at that graph, Diana, please. So that dotted line up there represents the shortfall that you have for that particular season, right?

I mean, you -- you -- the red line would represent what you've planned for. The dotted line represents what actually happened?

MS. LORI STEWART: This is -- it's a great opportunity to clarify. What we plan for are the two (2) dotted lines. So we do not plan a portfolio for an average or normal year experience.

THE CHAIRPERSON: Okay.

MS. LORI STEWART: Our exposure in that case would be significant. What we plan for is the range of potential market requirements that we could experience.

THE CHAIRPERSON: Okay. Having said that, why are you in the marketplace buying supplemental gas? I'm trying to understand why you're in there every day buying supplemental gas given that you've planned for a very cold winter already.

(BRIEF PAUSE)

MS. LORI STEWART: I'll -- I'll try to

frame this in a different way. We don't have the ability to pre-purchase commodity for the upper range of experience. What would we do with that natural gas if it was coming to our market at the beginning of November?

You don't know whether or not you're going to see or experience the upper dotted line or the lower dotted line. And that is truly the case. At the beginning of winter, we have no idea which of those experiences or where in between those dotted lines our market will consume natural gas.

So from -- from our perspective, there is no way, other than committing at -- at a baseload level, to take or pay volumes at the upper range of that experience, which would have us selling natural gas off in the market at a loss on most days out of most winters.

So economically, that strategy doesn't make sense for ratepayers. It's far more economical for ratepayers to have a one (1) in twenty (20) year experience like 2013/'14 where, yes, their commodity costs were greater than forecast because we were in the market buying in a very high-demand scenario.

But what follows on that is that there -- there should be, on an expected basis, those eighteen (18) or nineteen (19) out of twenty (20) experiences that follow where there either isn't a need for supplemental gas purchases or a very minimal -- minimal need for supplemental gas purchases. And that's your exposure to the supplemental gas market.

2013/'14 was a one (1) in twenty (20) year event.

THE CHAIRPERSON: Okay. You can see what we're struggling with here at the panel level. We're trying to understand why -- you -- you know, we understand -- at least I understand your asset position here. You -- you've -- you know, you've -- this describes your asset position, why you have established transportation and so on to support the load.

But there was another component going on here which was you were buying gas every day during that period. And we're trying to understand why is it you're buying gas during that period if -- if you had already planned?

And I think there's a disconnect between -- you're suggesting planned represents the blue. We're thinking planned represents the top of that dotted line, the red dotted line.

MR. NEIL KOSTICK: I'll jump in here

to try to put some perspective around the discussion. Obviously one (1) way to mitigate the amount of purchasing you have to make in the winter is your storage gas.

So we have a very large storage contract with ANR, and I'm going to be careful not to go into anything. CSI here, and if there are things of that nature, we can talk about it tomorrow as well.

But we are one (1) of the largest storage holders on the ANR system in Michigan. That is a huge storage system in Michigan, and we are one (1) of the largest storage holders.

So we make very good use of gas purchased in summer, with -- withdraw it in winter, and we're protected from price spikes in the winter with that approach.

But the fact is we do still need to buy gas in winter. And we're not aware of any LDC or gas utility that doesn't buy any gas in winter. So regardless of how much storage they hold, there is a certain component of purchases that do have to happen in the winter.

So -- and we know that this is the case both to the west of us and to the east of us. We know that Ontario LDCs hold a lot of storage in the southern Ontario area. They also bought a tremendous amount of gas throughout the winter, including late winter when prices were very high.

In addition -- in addition to that, to the west of us in Saskatchewan, the Saskatchewan LDC has a tremendous amount of storage within the province. And in normal circumstances, they can rely on their storage gas for much of their winter needs.

But our understanding is that, in '13/'14 winter, given how extreme it was, even the Saskatchewan LDC had to do a fair bit of buying in winter. There's no escaping it.

We're not aware of any LDC that doesn't have to make purchases in winter in order to supplement their storage withdrawals. So that's some perspective around the issue, I -- I hope.

MR. NEIL DUBOFF: Ms. -- Ms. Stewart is -- is desc -- has described that if you -- if you buy, you -- you commit to the volume and you don't need the volume, then you've got to sell it back into the marketplace at a loss.

Why would you have to sell it back in the marketplace? Why couldn't you just keep it in storage?

MR. NEIL KOSTICK: The -- the issue

becomes, if you're buying gas in the winter, if you're in an extreme environment like we were in '13/'14, you're buying that gas at a very high price.

And whether you're able to put it into storage or not, you're -- you're going to ultimately be burying that cost. And depending on where you purchase it, we're not able to dump it into storage.

MR. NEIL DUBOFF: But that's only to the extent that you're buying it in the spot market. Had you committed to it because you know -- what I understood is you plan for the high and the low.

To the extent that you plan for the high and you buy sufficient volume in order to -- to cover the high range on that chart, why not cover -- or could you explain why not -- why did you have the volume for the high range and -- and not buy it in the spot -- commit yourself to buy it, and then you -- you know what your prices are, and don't sell it back into the market if you don't need it?

(BRIEF PAUSE)

MS. LORI STEWART: If we were putting in assets, like, transportation capacity to move the gas from wherever you were buying it, and then additional storage capacity at a level to accommodate what -- your one (1) in twenty (20) year experience, that's not an economic course of action for ratepayers. Nineteen (19) out of twenty (20) years they will end up paying far more for fixed assets than are necessary.

So we -- we can't dump more gas into storage without contracting for additional storage capacity. And in all of the years that follow, in those eighteen (18) or nineteen (19) years out of twenty (20) where you don't require that storage capacity, your long assets, you'll recover pennies on the dollar relative to those assets and our ratepayers will end up with a much higher cost portfolio than is required.

MR. NEIL DUBOFF: And it's the storage issue that's causing that?

MS. LORI STEWART: It's storage. It's transportation capacity to get commodity to storage. So we would have to contract for transportation at a higher level in terms of contract demand than -- than we currently have in place. We fully utilize our storage facility at present. We ensure that at the start of the winter it is completely filled and ready to go to serve our needs, but the issue is one (1) of a tradeoff.

And in order to protect against rate volatility in the one (1) in twenty (20) year experience, the tradeoff for that is structurally increasing costs for ratepayers in the eighteen (18) or nineteen (29) years where those assets will not be required because we don't have the luxury of knowing when that will occur. That's the -- the -- that's the uncertainty.

THE CHAIRPERSON: So I just want to follow up on what Mr. Kostick said. You expect to buy gas in the wintertime. You normally buy gas in the wintertime. I mean, you have a storage portfolio. You buy gas in the wintertime. What happened in '13/'14 is the weather was much more extreme, so you ended up having to buy a lot more gas than you normally would and at prices that were far higher than we'd experienced in previous years.

I mean, that - summarize at the very level, that's what's happened right on the gas side?

MS. LORI STEWART: That's correct.

THE CHAIRPERSON: Okay. Now, you are buying gas -- during this period, you're buying gas -- I understand from the evidence, you're buying gas daily. You're buying gas for delivery in a few months time -- or a few weeks time rather. I mean, that's constantly going on throughout this period?

MS. LORI STEWART: That's correct.

THE CHAIRPERSON: Okay. And so the storage portfolio optimization you're doing requires you to -- to tailor your supplemental gas purchases to the evolution of your portfolio, as I understand it. In other words, some days you can pull more out of that storage than other days, so the balance would have to be supplied from supplemental gas?

MS. LORI STEWART: That's correct. We have a fixed amount of natural gas in storage. And what we're doing is actively managing that such that we have some protection against supplemental gas purchases throughout the entire hundred and fifty-one (151) day season.

(BRIEF PAUSE)

THE CHAIRPERSON: It'll be the right time to take a break. Let's take ten (10) minutes. Thank you.

--- Upon recessing at 10:30 a.m.
--- Upon resuming at 10:45 a.m.

THE CHAIRPERSON: Mr. Kostick, I think that the panel members are getting it finally. But if you want to -- if you want to speak to the issue that we've been addressing go ahead, but otherwise, you can go straight to your presentation.

MS. LORI STEWART: If we could call up Appendix 3.2 of Centra's Application, I'll -- I'll -- oh, I'm sorry, that -- that's CSI. I can't do that. But I can do that tomorrow. So we'll have a look at that, and I think -- I think that's part of the -- the difficulty here, is not -- not crossing the line.

So moving on in terms of the challenges that Centra faces, its mandate to serve translates into: We -- we need to be able to respond to load variability, and we also need to be able to meet our peak firm demand. And those two (2) things -- an example of being able to respond to load variability, here is a real life example from a couple of months ago where the load to serve on May 16th was 50,000 GJs per day, and the load to serve on May 17th was 140,000 GJs per day.

So there's a real life example of the day to day load variation that we can experience, and perhaps that as well will -- will inform your thinking about our ability to pre-purchase commodity because this is the type of variation and the risk that we have in terms of pre-purchasing commodity.

Our last challenges are geographic location. And we've got a map in front of you of the TransCanada mainline system. And over to the left-hand side you've got a red arrow pointing to Empress, which is a receipt and delivery point at the Alberta/Saskatchewan border. It's the commencement of the TransCanada mainline. And the other red arrow is pointing to Emerson.

So you'll hear those words often throughout the proceeding whether or not we're talking about our contracts from Empress to the load centre, or Emerson to the load centre, and the load centre you can notionally think about that as Winnipeg.

So one of our geographic challenges is the fact that we're captive to the mainline. Not a molecule of gas moves onto Centra's distribution centre -- or distribution system without first having moved on the TransCanada mainline. And secondly, in terms of geographic location we have -- we don't have access to local storage, which is certainly preferable.

If you can have your storage site situated as close as possible to your load centre, that would -- that would reduce the need for transportation contracts to connect storage with your market centre. And it also may allow better access to responding to that variation that we can experience day over day. The closer your storage facility is to your market centre the better, in our world. We don't have that benefit. Our -- our storage is, of course, situated in Michigan.

In terms of high-level portfolio strategies, we've -- we've already talked about strategy one (1), improving the purchase load factor, and thus the unit cost of our transportation. And the primary way we do that is with seasonal storage in Michigan.

Increasing our takes all summer when our market does not have a very high demand for natural gas, improving the number of volumes that are moving through our capacity during the summer months, and then we flip over into the withdrawal season out of storage and because of our access to -- to 15.5 PJs of natural gas, that allows us to hold less transportation during the winter months when we need to be able to range up to our peak.

Another strategy is to optimize the utilization of higher cost assets. And so given what's in our asset portfolio, we are -- we are maximizing the use of our long-haul, mainline, firm transportation capacity from Empress. If I move back to the map you can see that the distance of haul from Empress to the load centre is significantly longer than the distance of haul from Emerson to the load centre. And the transportation rates are -- are priced accordingly.

We're evaluating cost-effectiveness over the long-term. So when we're designing a portfolio we're not attempting to design for one (1) perfect year. We're designing over -- using twenty (20) years of actual weather history. And then we're generating random weather patterns around that actual history that we have, in order to ensure that we understand the range of requirements that must be met.

Other portfolio strategies are ensuring the diversity of supply hubs from which we're purchasing commodity. So we purchase natural gas commodity at AECO, at Empress, at Emerson, at Michigan, and at Jolliet in the Chicago area. We're ensuring transportation path diversity, so we have a forward-haul contract from Western Canada, and a back-haul contract from Michigan.

And we're embedding both reliability

and operational flexibility. And we do that by way of our storage contract. We have a swing component of our western Canadian supply contract. We have supplemental gas swing arrangements. And when I -- when I use that term that -- an example of that is where we have the right to call zero GJs of gas on the day. Or we have the right to call twenty thousand (20,000) on the day.

And a -- a counter-party commits to provide us with that optionality in the arrangement, and the use of a light night nomination window providing us with one (1) more opportunity to alter our takes out of storage and thus reduce our exposure to pipeline balancing fees. These swing components, when I talk about the swing component --

MR. NEIL DUBOFF: Excuse me. Could you just explain that late night nomination window? I don't know that phrase.

MS. LORI STEWART: Sure. Within the gas day at present there are four (4) nomination windows associated with it. Two (2) of the nomination windows are day ahead. So if I'm talking about the gas day that starts at 9:00 a.m. tomorrow morning, there are two (2) nomination windows today where we submit our first estimate of how much gas will be burned tomorrow. If it's tomorrow, so Tuesday, 9:00 a.m., until Wednesday 9:00 a.m. is the gas day in question.

So today our schedulers will be submitting their first estimate to the pipelines of how much gas they need for tomorrow. They have another opportunity at the end of the day today to correct that, to make adjustments based on what's happening in our market, based on what our T-service customers are doing, based on the hourly SCADA reads that are coming to them informing of how much gas is being consumed relative to their outlook.

Then once the gas day has commenced tomorrow, there are two (2) more opportunities to adjust as the day is proceeding in real time. Again they are using their hourly feeds to alter their estimates of how much natural gas will be consumed within the market by the end of that gas day.

During the winter months we have access to a third nomination windows. And our schedulers come on shift in the middle of the night. They work from 11:00 p.m. till 2:00 a.m., in order to have one (1) last look at the market, at what's being consumed. And then they make a further nomination adjustment that's effective at 5:00 a.m.

So it allows us to optimize our balancing fees on the pipelines because they're able to tweak one (1) more time based at that 5:00 a.m. effective window.

When I -- when I see these options that we -- we use or strategies that we use to embed both reliability as well as operational flexibility, two (2) of them are talking about swing components where we have a swing component in our western Canadian supply contract or we have supplemental gas swing arrangements with counterparties where the counterparty is committing to us to allow us the option to call nothing or to call at the maximum level of the swing arrangement.

The -- the planning that we do is -- is in terms of planning around the range of potential market requirements. We're putting in place the transportation capacity to ensure that we have the ability to move gas to the market.

But any of these swing components from a commodity per -- perspective are indexed to a daily index, a spot index for natural gas, because the very nature of the swing arrangement is we don't know in advance whether we will need any natural gas.

And these are -- are very important

components of our portfolio because we may need zero or we may need at the maximum level. But swing -- swing arrangements by their nature provide exposure to a daily index or a spot price.

So the transportation assets are sitting there at the ready, and they're designed to ensure that we can meet the range of potential market requirements. But if the commodity -- commodity purchase is indexed to a daily index, then you will pay the spot price.

THE CHAIRPERSON: Do you have to pay for the -- do you have to pay for the -- the transportation ahead of time? If you have a swing arrangement for supplemental gas, are you paying for the transportation whether you take the gas or not?

MS. LORI STEWART: Definitely. The alternative would be that we're moving natural gas on an interruptible basis, and that is not acceptable to us. We don't have the option to have our nomination for gas cut because it's interruptible transport.

In terms of operational strategies, these are the four (4) strategies that are deployed every single gas year. The first one is to be positioned for the range of potential market requirements that may occur. That happens every gas day, that happens every gas month, that happens every gas year.

The next three (3) are winter strategies, and I'll step through -- step through these now. I've already talked about operation strategy number 1, and it is a part of our world every single day, being positioned for the coldest forecast outlook and the warmest.

Operational strategy number 2, the first of our winter strategies that we deploy, is to protect our seasonal storage inventory. We have a -- we have a contractual limit to the amount of gas that we can pull out of storage.

We've contracted for 15.5 PJs of storage capacity in Michigan, and we're wanting to start the winter by protecting that seasonal storage inventory. And we do that by commencing purchases of supplemental gas on November the 1st.

We're making use of our supply hub diversity. So even when we have a swing arrangement in place at a hub like Michigan, on the day -- one (1) of the benefits of the swing arrangement is on the day, if Emerson is cheaper, we can leave the swing arrangement at Michigan behind.

That's the optionality that's embedded

in the contract with the counterparty. And we can price arbitrage on the day given the swing arrangements that we put in place at the commencement of the winter.

And this operational strategy, it -- it speaks to the competing objectives of the utility because we're balancing our interruptible customers' expectations when we start protecting seasonal storage inventory on the very first day of winter.

One (1) option would be to turn off or cur -- to curtail interruptible customers commencing November the 1st and until such time as we had more certainty as to the end outcome that we may experience. We don't do that. Alternatively, we commence purchases of supplemental gas in order to not commence cur -- curtailment of interruptible customers at the start of the winter.

At any point when I'm talking about curtailing interruptible customers please understand that in the normal course and in the vast majority of circumstances we provide interruptible customers with the option to continue burning gas. It's a service called alternate supply service and it's an option that they have. They can make a decision whether to revert to their backup fuel or to have us enter the spot market and buy natural gas for their benefit.

So when I say 'curtail', in -- in most instances, interruptible customers are -- are continuing to actually consume natural gas; it's just under alternate supply service.

MR. NEIL DUBOFF: Can you remind me just again of what percentage of your volume that you're selling to customers is through the interruptible customers?

(BRIEF PAUSE)

MS. LORI STEWART: We're going to look at that chart again tomorrow. If --

MR. NEIL DUBOFF: No -- no problem. No problem. I -- I sort of was trying to be clear about your -- your comment about an option would be to start by cutting off the interruptible customer starting on November 1st. And -- and I'm not sure why you couldn't do that, and -- and if the winter is mild, then bring them back on.

Could -- I don't know if that logic works. Could you speak to that?

(BRIEF PAUSE)

MS. LORI STEWART: When I'm talking about the -- the competing objectives of the utility, I think one (1) of the potential risks if we commenced winter with our interruptible class effectively curtailed, one (1) of the risks that we run is that they would no longer find value in the service and, thus, would move from being interruptible to firm.

And so that's that balancing act that I'm talking about where the inconvenience associated with being an interruptible customer, you have to balance that with the economics of -- of the discount that they receive in order to do that.

Operational strategy number 3 is to augment daily deliverability. And this is when we're approaching a scenario where our daily firm deliverability may not be sufficient in order to meet our market's needs and we move then to curtail interruptible customers on that day and to call on peaking arrangements if that -- if those arrangements represent our most economic source of gas at that -- at -- on that day.

And then operational strategy number 4 is to protect storage deliverability for firm customers, which Centra was doing throughout the winter of 2013/'14. And that is to purchase incremental supplemental gas as required to accomplish three (3) things: To extend the date to which maximum daily storage deliverability is maintained because once our storage facility -- once we've drawn it down to the 20 percent remaining inventory level, we will start to hit storage ratchets which reduce our daily deliverability out of storage. So we're looking to extend the date to which we are maintaining maximum daily deliverability.

We're wanting to protect our storage inventory to the end of winter such that we have access to it right to the end of March. And we want to delay sustained curtailment of interruptible customers.

So that's a strategy that gets deployed to different degrees or the timing of it will change every gas year, but the strategy is deployed every year. And again, to curtail interruptible customers as required.

Now, how has Centra's portfolio performed? Our portfolio has performed reliably and cost effectively. Our mandate to serve was met even in the extreme winter conditions, and -- and some extraordinary market conditions in 2013/'14.

From an annual bill impact perspective,

Centra's portfolio performed very well throughout 2013/'14. We've got the different disposition periods there, but even equalized for disposition period, we have a total bill impact for Centra customers of seventy-eight dollars ($78) relative to bill impacts for Enbridge customers of six hundred and nineteen dollars ($619), and annual bill impacts for Union's customers ranging between a hundred and eighty-eight (188) and a hundred and ninety-nine dollars ($199).

We are very experienced at managing our portfolio through a wide range of weather, through a wide range of market conditions, and at the end of the day none of us like to pay seventy-eight (78) more dollars per year on our energy bill. Given the context however, we are very proud of the work that we did through the winter of 2013/'14 and with the outcome that you're seeing there.

MR. NEIL DUBOFF: So the -- the thirty-nine (39) -- the seventy-eight dollars ($78) you're talking about is a -- is a recovery of the entire loss that took place in those years over a two (2) year amortization. Is -- is that correct?

MS. LORI STEWART: Yes. The -- the arithmetic you're doing is -- is correct, recognizing it wasn't a loss. It was an incurrence of -- of costs.

MR. NEIL DUBOFF: Right.

MS. LORI STEWART: Yeah.

(BRIEF PAUSE)

MS. LORI STEWART: Turning now to the need for a non-public part of this process, I think it was Mr. Rainkie who -- who opened up this morning, or perhaps it was Mr. Czarnecki who said, We would -- we would prefer an entirely public process. That has been our background for the entire time that we've testified before the PUB.

However, Centra is captive to the mainline. If you think back to the map that we looked at of the TransCanada mainline, we are different from a utility who may have access to multiple pipelines by which to bring gas to their market. That's one of the distinguishing features of Centra relative, for example, to our eastern Canadian counterparts.

And being captive exacerbates the market power of the mainline's unlimited pricing discretion. Essentially tolls for short-term transportation services on the mainline have been unregulated. And this pricing discretion, or the deregulation of tolls was granted by the NEB in an effort to facilitate maximization of revenues for a pipeline who is struggling to remain competitive. And I mentioned already that -- that tolls -- the end result is that tolls for -- for short-term transportation services have been deregulated.

Now, publicly available information, just like in an investment market or a securities market, can be used by TransCanada traders to maximize revenues and profits. So anything that is in the public forum is fair game. The only prohibition is on bid floor personnel's access to non-public, shipper-specific information. And that prohibition is as a result of Centra's intervention in the RH-1 2014 proceeding.

We identified for the NEB in that proceeding the -- the unfairness of TransCanada being able to reach into its own internal systems and have its traders use that information against a party like Centra, who is captive. And following that proceeding there has been a bid floor personnel information policy that was reached. Agreement on that was reached through the mainline tolls task force, through a consultative process. And Centra was a big part of ensuring that this prohibition now exists.

However, it's up to captive shippers like us to ensure that bid floor personnel cannot access information in a public forum that they can -- can then use to optimize their activities, including profits and revenues for TransCanada shareholders.

MR. NEIL DUBOFF: Ms. -- Ms. Stewart, are there many other captive shippers like Centra using the mainline, the TransCanada mainline?

MS. LORI STEWART: Yes, there are. Another Intervenor in the most recent proceeding was a power generator, who is located on the northern Ontario line portion of the -- of the mainline. So there are -- there are a few of us who are captive.

MR. NEIL DUBOFF: Are there -- are there utilities as well?

(BRIEF PAUSE)

MS. LORI STEWART: Portions of Union Gas service territory are captive to the mainline. But the -- so you saw a distinction between Union north and Union south rates --

MR. NEIL DUBOFF: Right.

MS. LORI STEWART: -- in terms of the -- the bill impacts. The Union north market, which is northwestern Ontario, that market is captive to the mainline as well as -- as Centra's. But the -- that -- that market only represents 10 percent in terms of volume of Union's overall service territory. So the vast majority of Union's ser -- service territory is not captive. However, that -- there is that small exception.

MR. NEIL DUBOFF: Do you know if in Ontario the -- they have gone to a non-public process in relation to Union Gas, because they've got a component of their service that's also captive?

MS. LORI STEWART: The RH-1 2014 proceeding that I've referenced a couple of times, the subject of that proceeding was a comprehensive settlement reached between TransCanada and the three (3) eastern Canadian LDCs. Union Gas, Enbridge Gas Distribution, and Gaz Metro.

One (1) of the planks of that settlement agreement, whereby the eastern Canadian LDCs obtained the commitment of TransCanada to build facilities that will allow them to access natural gas from basins that are -- are more in proximity to their markets -- so basins like the Marcellus and the Utica -- currently the TransCanada system capability is limited in terms of those markets, accessing gas from there.

So in this comprehensive settlement agreement, one (1) of the things that the eastern Canadian LDCs agreed to in order to gain access to Marcellus and cheaper sources of supply was that they would support pricing discretion on the mainline.

So in the process of evaluating the tradeoffs associated with these service provisions, the eastern Canadian LDCs viewed access to Marcellus as -- as being more valuable to them than the potential exposure to pricing discretion. And contractually, they are committed until the end of 2020 to support mainline pricing discretion.

So it -- I -- I can't speak for them in terms of that tradeoff and -- and why they made it, but that -- that's the contractual commitment that they have.

THE CHAIRPERSON: Pricing discussion on the firm transportation or just on the short term?

MS. LORI STEWART: Pricing discretion only relates to short-term transportation services.

THE CHAIRPERSON: Now, the mainline would be aware of your firm transportation arrangements, all of it, wouldn't they?

MS. LORI STEWART: Any shipper's

contractual arrangements, once the contract has commenced, become publicly available.

(BRIEF PAUSE)

MS. LORI STEWART: That summarizes my portion of the presentation, and I'll turn things over now to my colleague, Mr. Sanderson, unless the panel has any -- any additional questions for me.

THE CHAIRPERSON: I want to talk about the short-term transportation arrangements. You would be making them of variable lengths and variable amounts with the mainline operator.

(BRIEF PAUSE)

MS. LORI STEWART: The -- the form of short-term transportation service that Centra has accessed historically is short-term firm transportation. That's a service offered by the mainline for a duration of -- seven (7) days is the minimum term up to three hundred and sixty-four (364) days is the maximum term as compared with firm annual transportation which you're contracting for three (3) -- three hundred and sixty-five (365) days.

The other form of short-term transportation that is affected by mainline pricing discretion is interruptible transportation. But you've already heard me describe how a transportation service that can be cut by the pipeline doesn't fit well with Centra's mandate to serve.

So it's historically been short-term firm transportation that Centra used to load shape or better match the shape of its -- its load with its actual assets in place.

As a result of the deregulation of short-term transportation services, TransCanada has made a decision to economically withhold short-term firm transport. So it's mandated to offer it, but it offers it at a price that is in excess of holding firm annual transportation. So there would be no reason, from an economic perspective, to ever contract for it.

There's some variation around that, but for Centra's market, short-term firm is being economically withheld. And that gets into how Centra filled that gap. And I -- I can't speak about that here today, but I -- I'll be happy to step into that conversation tomorrow.

THE CHAIRPERSON: But the pricing is transparent? In other words, you know what they're pricing their short-term transportation? Is it publically available information? Do you know what the -- what -- can you see patterns? Can you see...?

MS. LORI STEWART: As it relates to short-term firm transportation for our market centres, the pattern I see is that it's priced higher than firm annual transport. So the message being sent to us is it's not available to you. There's no economic incentive for us to contract for short-term firm.

If -- if I can get three hundred and sixty-five (365) days of transportation at the same or lesser cost than a short-term firm arrangement, then I'll take it because there may be the opportunity to mitigate my unutilized demand charges. Thank you.

(BRIEF PAUSE)

MR. BRENT SANDERSON: Members of the Board panel, I'd just like to walk all -- all of you through Centra's gas cost deferral balances for which it's seeking final approval in its application, as well as new non-primary gas base rates for the 2015/'16 forecast year for which Centra is seeking interim approval in this proceeding.

Centra is seeking final approval of

prior period gas cost balances for three (3) distinct historical gas years. If -- and a total amount of $59.3 million recoverable from customers as of October 31st, 2015, for the three (3) years in combination, these balances break out between the three (3) aforementioned years as follows: $3.6 refundable amount to customers from the 2012/'13 gas year and remaining prior period deferrals prior to that year; $49 million recoverable from customers for the two thir -- 2013/'14 gas year; as well as a $13.9 million recoverable amount for the current 2014/'15 gas year.

Centra currently has rate riders in place to recover approximately 50 percent of the 2013/'14 amount recoverable from customers that were first implemented on November 1st, 2014, and were subject -- subsequently adjusted on February 1st, 2015.

Centra currently expects that by October 31st, 2015, $23.2 million of this amount will have been recovered by customers through these rates and are seeking new rate riders to be implemented on November 1st, 20 -- 2015 to recover the remaining $36.1 million amount of these prior period deferrals over the twelve (12) month period ending October 31st, 2016.

A gas cost deferral account -- a primary gas deferral account being but one (1) of number of different types of gas cost deferral accounts, their purpose is to capture differences between actual upstream gas costs being incurred by Centra, those related to the commodity itself, Centra's storage and transportation arrangements. In addition to those, unaccounted for gas on Centra's distribution system and other smaller deferral accounts, such as our heating value margin deferral to capture the difference between those costs actually being incurred and the costs that are actually being recovered in customers' base rates over a period of time.

The resulting differences between those two (2) amounts -- and I'd like to point out that whether it's an amount refundable to customers, that does not rese -- represent a gain for Centra, nor does an amount recoverable from customers represent a loss. Deferral balances are a normal part of Centra's business and are to be expected from year to year through -- in the normal course.

Those amounts, either refundable or recoverable, are flowed through and disposed of in rates in periods subsequent to the periods in which they were accumulated and ensures that upstream gas costs and these other minor amounts on Centra's distribution system are ultimately passed through to customers and rates over time without markup; no more, no less. In other words, they're integral to the gas cost passthrough mechanism.

That is a typical mechanism that is employed by virtually every natural gas local distribution company in North America. And PGVAs and deferral -- gas cost deferral accounts are an integral part of that mechanism which you will find in virtually any natural gas utility anywhere in North America.

MR. NEIL DUBOFF: Mr. -- Mr. Sanderson, so these -- these gas cost deferral accounts, I -- I see how they work and I -- I understand why they're -- why they're there. How does the system, because it's used across North America so I'll -- I'll call it a system so to speak.

How does the system account for the fact that the monies that you're refunding or charging to customers may not be the customers who incurred the -- the cost in the first place? Because I think they call it an intergenerational issue where -- where the customer today may not own the house they had last year, or -- how do -- how does the system deal with that conceptually?

MR. BRENT SANDERSON: That's an imperfection, if you would like to call it that, in -- it's inherent in any gas cost pasture mechanism. So to the extent possible, Centra and any other utility would seek to dispose of these balances, whatever they are, refundable or recoverable, in as expeditious a fashion as possible while having regard for smoothing the impacts on customers because we've got conflicting objectives here.

The faster that you reflect your actual costs in rates, the more volatile your rates are, both up and down. So we walk the fence, if you will, in terms of tyring to smooth customers' rates to the extent possible while not knowingly or -- or not knowingly building up large gas cost deferral balances as a result of that.

So it's a bit of a -- it -- it's a bit of a balancing act, if you will, and therefore we would want to do this over a reasonable period of time that has regard for the inter -- possible intergenerational affects while having regard to keeping the impacts to a manageable level and avoiding what would be referred to as rate shock for customers.

MR. NEIL DUBOFF: But -- but any utility board in any province in any jurisdiction across North America, they have to look at the customers who will be affected by these charges. And if you have a year like '13/'14 the -- the charges are not -- may not be insignificant to an individual consumers on their rates in a -- in a year subsequent to an unusual event.

And -- and how does the system sort of justify a customer in a subsequent year, even if it's only a one (1) year amortization or if it's a multi-year amortization, a customer in a subsequent year, how do we say to the public, You're going to be paying a charge based on the fact that the person in the year before didn't pay enough?

MR. GREG BARNLUND: If I could step in now, Mr. Duboff. If -- if you would, it is a balancing act. And -- and there has to be some determination or some decision made in terms of balancing that intergenerational issue with -- with rate stability.

Now, the other -- I guess the other factor that should be recognized with respect to Manitoba is that we have a relatively stable market in terms of the customers within Manitoba. So, a large residential customer base with relatively little turnover in terms of residential customers.

So, myself and others, you know, we're representative of a large number of -- of rate -- gas consumers and ratepayers in this province where -- I mean, I -- I consumed gas through that period of time. I continue to consume gas today. And I'm going to be -- the timing of how that cost is being recovered from me is being reflected in this particular filing, but it's not unreasonable for us to do that. The number of turnover of customers is relatively small.

It also -- and I'm going to touch on in my presentation some discrete adjustments we made to rate riders for large volume customers that actually moved customer class through that period of time. So we actually undertook steps to be able to track those customers, and be able to track then the recovery of the costs that they drove through a period of time through a subsequent period.

MR. NEIL DUBOFF: Can -- following up on that. You -- you said a couple times just now that the turnover is relatively low. For me it's going to be important to know what -- what kind of numbers we're talking about in a -- in a percentage of -- of customers who may turnover in a given year because to the extent that they're the same customer in year two (2) is the year that they -- they had two (2) low rates, it's not an issue.

But how many people are we talking about, or how -- what percentage of the customers are we talking about?

MR. GREG BARNLUND: Well, let me speak in general terms. I think that we add probably about between two (2) and three thousand (3,000) new customers to the system every year; that's the number -- that's the amount of customer growth we see.

Overall, we may have a turnover of maybe twenty (20) or twenty-five thousand (25,000) customers, but many of those customers are moving from one (1) residence to another, or they're moving from one (1) -- from a townhouse to -- to a detached house. We -- we can't keep track of everybody. There will be some customers that, through a period of time, have converted heating systems or converted, you know, their -- done renovations to their house, that type of thing, and may have replaced a furnace with a heat pump for example. Well, we can't -- you know, we can't define it down that closely.

But in general, we find that -- that, you know, given the -- the relatively low turnover overall when we take those things into consideration, that it's not unreasonable to -- to expect customers to pay the, you know, a -- a rate rider for a twelve (12) month period, or a twenty-four (24) month period to be able to recover those costs.

The other thing, too, is we look at primary gas. The majority of the -- of the commodity that we sell to customers is primary gas. We're talking about supplemental gas, but on a normal year primary gas is 92 percent of the con -- volume consumed, and supplemental gas is 8 percent of the volume consumed. So fluctuations in the supple -- cost of supplemental gas are relatively small in comparison to the -- to the primary gas cost that they're paying.

Primary gas costs are adjusted four (4) times a year. And so we reset the riders. We -- we look at the deferral account balances four (4) times a year, and we reset that. So we think that for the majority of the gas costs that are being passed through to customers that there's a -- a reasonably responsive mechanism that exists within our existing rate-setting methodology.

THE CHAIRPERSON: Reasonably responsive. But I guess one (1) of the issues that we're going to have to address is the fact that the PUB was first alerted to the significant shortfall in the purchased gas variance account in June. And -- and, you know, we -- we could have addressed it a lot earlier than that, if we had been made aware -- if Centra had made us aware of the shortfall that was occurring the mid -- during the midst of that winter. And now -- we're now in a -- we're now in a scenario where we're trying to collect money from ratepayers that relates to a -- a number of months ago.

And -- and I guess the question is, you know, what happened? What -- why -- why didn't Centra come back to us in February and tell us that there was a shortfall in -- you know, a significant shortfall in their purchased gas variance account?

MR. GREG BARNLUND: I -- I recognize that that's a concern of the Utilities Board. And -- and if we look at sort of in the normal course of events of what would transpire during a year, we would be making a rate application in the wintertime. We would close our books on a gas year October 31st. And we'd be notionally looking at determining what was the -- what was the impact? You know, what -- what is our level of deferral account balances, and what do we see as the forward price of gas? What is the merit in going ahead with an application to change rates as -- at a given point in time?

So we would be doing that in the November/December time frame, and we'd be looking to make an application for a gos -- gas cost adjustment. In the December/January time frame we would make a filing, and that -- those rates would then be put in place for non-primary gas costs, let's say, August 1 of the following year.

So if we look at the events that transpired in the -- from the November '13 to the January '14 period, we -- we basically did that. And we took a look at the deferral account balances. We took a look at the -- the forward strip. We took a look at, you know, what the forecast, you know, gas cost would be. And at that point in time even till, you know, understanding that the accounting mechanisms have some timing associated with it. In other words, if you close the books in December you're only going to get information later in January in terms of those -- those deferral account balances.

So, when we notified the Board in January that, in our perspective, there wasn't a -- a need to go forward with a rate application at that point in time, it was because that our -- all of our forecast information was indicating that the course was fairly normal within the range of events that -- that we would see from a rate perspective if we outlooked our costs to the end of the gas year.

Now, it was late in January, in the February/March time frame, of course, that deferral account balances -- or the -- the market was starting to act in the way it was. But at the same time, we're also looking at that from the perspective that we have deferral accounts in place to be able to capture these fluctuations; that's the purpose of them.

We also have a rate site -- rate-setting methodology where we're going to use rate riders to be able to, you know, tune those recoveries from those customers, so that we're balancing the considerations of price transparency and -- and rate shock or rate impact to customers.

We also wanted to be able to get through the winter period because it's sort of like crying, Fire, in the middle of a crowded theatre, if you would, if you looked at what was happening on certain days in February but you don't know how the rest of the winter is going to materialize.

But notwithstanding how the winter materializes, these are being captured in a deferral account. And, you know, it -- that's the purpose of the deferral account. We'll be able to understand the quantum of these at the conclusion of the winter.

We did our analysis at the end of winter, and we advised the Board in June of the situation and advised that we were looking to accelerate the filing of an application because normally, in the normal course, you'd let it go to the end of the gas year and then file an application the following winter.

So we actually accelerated the course of action, made our interim filing seeking changes for November 1 rates.

THE CHAIRPERSON: So you -- given that this is a flow-through account and not affecting the main accounts of Hydro or Centra Gas, you would have been aware of a problem in February probably.

And I guess the -- the question is: Why not come back to the Board and say, We've got a problem, we need to adjust the rates. We could have given you a rate -- hypothetical, but we could have given you a rate right away to address the evident shortfall in that account.

And I guess what I'm hearing from you is that, No, we've got to close the books, we've got to -- you know, there's got to be a way in which you can tell that your account is under water well before you end up closing the books at year end.

MR. BRENT SANDERSON: Mr. Chairman, if I might, it's important to be mindful of the fact that supplemental gas purchase variance account balances are driven by two (2) mechanisms. One is the difference in the unit cost of our supplemental purchases that we're making on behalf of customers and the unit cost that's embedded in their base rate. And then there's the absolute magnitude of the supplemental gas purchases that we're making.

So in February, we started seeing that price mechanism start moving. But keep in mind that we had no idea whether over the remainder of the winter we'd buy any meaningful quantities of supplemental gas at that point in time.

So if we jump the gun and we pass through what would, on paper, appear to customers like possibly a 20 or 30 percent annual bill increase, and then subsequently not -- have turned out not to have required that rate increase because the weather warmed up subsequently -- I'm going to talk a bit as I move on in my presentation about the winter of 2000/2001. It was a classic example.

It started out November and December of that year extraordinary near record cold. Things looked very, very bleak at the beginning of January. And as Ms. Stewart alluded to earlier in her presentation, winter just evaporated after the first week of January and there was no more winter weather.

So we could have just as easily had a situation like that. And it's for that reason -- the key reason why we file annually for supplemental gas base rates -- one (1) of the reasons is -- is mid-year at any point in time, we don't know what our requirements will be in terms of supplemental gas purchases over the remainder of the year, sometimes if anything.

So to advance rate adjustments on the basis of what might appear to be a large build-up on a forecast basis under a number of different assumptions, it could turn out to be wrong the minute we'd filed them.

That's why we hold those rate adjustments to an annual basis as opposed to our primary gas rate where the purchases are much more stable, much more -- we have much better visibility before the fact as to those purchases, and then we can safely flow through adjustments in the unit costs of those commo -- of those purchases on a more timely basis relative to something like supplemental gas where we just don't even have the certainty whether we're going to have, as Ms. Stewart said, a maximum year with, you know, over 10 million gigajoules of supplemental gas purchases versus a year where we purchase virtually nothing.

So that's one (1) of the difficulties in trying to get out ahead of this is it could have been counterproductive in terms of what the intended benefit would have been to -- in doing so.

MR. NEIL DUBOFF: And -- and that -- that's a great answer about what happened in February. But there was nothing filed until June. Why not March when you knew it was still go -- continuing bad or April? There's a number of months after that. Why -- why didn't we know till June?

MR. BRENT SANDERSON: Well, again, I think it's a matter that, you know, we have a perspective in terms of the stabilization of rates for customers. And now, you know, I'll get to the slide in my presentation where we look at -- at the total residential customer bill over a number of periods to this period of time.

And you'll see that -- that basically,

our rates have been reasonably stable, within a range of a hundred dollars a year on an annual customer through that period of time.

A counterpoint would be in Alberta, where you set rates twelve (12) times a year. And if you would turn up tab 2. And page 13 on Tab 2 you'll see the -- the price chart which we're talking about, this period of time.

And if you are setting rates more quickly, like in Alberta, they'll adjust that rate every month. So a customer's rate will spike enormously in one (1) month only to be, you know, significantly lowered in other months following it as those prices come off. Or if you've over recovered from customers, you will exacerbate the swing in price because you're going to refund customers' money back on top of a lower rate for the following month, so there's a balance there. And we try and to walk a line --

MR. NEIL DUBOFF: But with respect, I'm not sure that's really answering the question, with -- with respect.

I -- and -- and I say that because we did know, in fact, it was getting really out of hand in terms of the greater charge for the supplemental gas certainly by March or April and it would have allowed us to consider -- the Utilities Board to consider an increase which could have stopped that shock.

So I hear you about not wanting a shock. But by not dealing with it when it was dealt with, doesn't that create a greater shock for the customers in subsequent years?

MR. DARREN RAINKIE: Mr. Duboff, maybe I can chime in here. I'm not sure I understand the question: Would have stopped it? It was a phenomena, the -- the costs built up in I think primarily February and March. So it would -- filing a rate application wouldn't have stopped the buildup in -- in the account. The question is: What's a reasonable way to go about disposing of it?

As Mr. Sanderson indicated, the supplemental gas PGVA has a strong seasonality to it, so it's important not to overreact to it. I remember having discussions with Mr. Barnlund and we actually decided that we would wait and see what happened during that period of time before we put an application forward.

I mean, when -- when extraordinary things happen I think you want to take some time to reflect on it. We wanted to decided -- look at the quantum and the period of time over which we would want to recover it. But we strive to adjust to rates four (4) times a year. And that's enough, from our perspective, in terms of adjusting rates because we have to look at those objectives of rate stability. We don't want to adjust rates twelve (12) times a year.

So, you know, it's February, May, August, and November. So we looked at it. We decided what we wanted to do. We filed some information in June. The reality is, is there's very little volumes between August and November anyway, so it wouldn't have really made much of a difference. I think, if you look at the circumstances and the seasonality of the account, and looking at it, perhaps we could have started some disposition in our August 1st adjustment, but given the small volumes, I don't think it would have made much of a difference in the -- in the longer term, but it certainly wouldn't have stopped the phenomena.

And -- and I think we're -- we're kind of looking at 2013/'14 as some stupendous event and pushing it out. I mean, we've managed gas costs for decades in -- in Manitoba Hydro and Centra, and that's the way we look at it. Cold years there's going to be higher costs. And customers -- this is a deregulated commodity market; customers pay that. We can't shelter them from paying that. We -- we try to smooth it as best we can, as reasonably as we can.

But there's lots of years when gas costs are lower and -- and there's refunds out of these accounts. So we can't develop a system around the one (1) in twenty (20) years. I think we shouldn't overreact to the one (1) in twenty (20). We need to look at the -- the whole system and how it works. And it's worked very well in Manitoba here for -- for decades.

But I -- I don't think, as Mr. Barnlund alluded to, overreacting to it really would have changed -- it wouldn't have changed the outcome. Perhaps we might have started some disposition on August 1st. But we were prepared to use a twenty-four (24) month amortization period versus a twelve (12) month amortization period at any rate, so, you know, we were -- we were looking at that.

It takes time to file a rate application. It takes time to get the information out of the GL. But I think, more importantly, looking at the seasonality of that account, it was the right thing to do, to make sure we understood what happened, what the final balance was.

I think it was the right thing to do to look at a proper amortization period for this on behalf of customers. And I don't think it really would have helped in the end to overreact and propose some type of -- you know, we adjust rates four (4) time a year, so once every three (3) months, some type of inter-month adjustment.

I mean, we already adjust rates for Manitobans four (4) times a year, and I think that's a reasonable tradeoff between price transparency, rate smoothing, and all those types of objectives that we look at every day.

MS. MARILYN KAPITANY: So, Mr. Rainkie, you're saying it wouldn't have been feasible to do something for May 1st of that year?

MR. DARREN RAINKIE: Well, I recall having a conversation that -- because it -- it was brought to the attention of the executive in February or March that we wanted to look and see -- because of the seasonal nature of the supplemental PGVA account, it can go up and down between refunds and recoveries very quickly, we wanted to make sure we knew what we were dealing with. We -- we didn't want to overreact.

This is why we have purchase gas variance accounts. I mean, we can capture the differences, and we can take a sober second thought, and we can look at how we recover them. Most of time if they're small balances, we recover them over twelve (12) months and limit the -- any type of intergenerational issue.

With the larger balances, we -- we take pause on them, and we look at how -- how they should be recovered. We look at things like the switching of customers between classes, and how we would deal with that so it's fair. Like we -- we don't rush into those types of decisions. And then it would take some time to prepare a Rate Application.

But we wouldn't have wanted to adjust rates. I would never have contemplated adjusting rates between, you know, a quarter. I think it was most practically either August 1st or November 1st, but as I said there's small volumes in the -- in the summer, so I don't think it would have rally made a material difference if you -- if you look at it in proper context.

MR. BRENT SANDERSON: Just to sort of close off on what Mr. Rainkie just said, we need to keep in mind that we're not talking about an under recovery of 50 percent of our annual gas costs here. Something more dramatic than that.

Somebody who has come on the scene as it relates to natural gas regulation in recent years in a three (3) doll -- two (2) and three dollar ($3) natural gas environment could be forgiven for looking at that askance and saying, That's a very large number.

But we have the benefit of historical perspective of having been in this business for a number of years, and been through a number of trying circumstances, and we're talking about a little bit more than 10 percent our annual gas costs that year. And a deferral balance that is by no means catastrophic, and I'll -- as I go through my presentation I'll give you some historical context within which to put the winter of '13/'14 in some historical perspective.

But as Mr. Rainkie said, the appropriate thing to do at that time was to reflect. We were not -- the Company was not facing any cashflow issues for having to carry that balance. Carrying cost issues are minimal given the low overnight lending rates right now, so there's not massive carrying cost implications of an extended deferral.

And as I said, it -- knowing the uncertainty and the volatility to which we're exposed every day, every month, every year, it's been my experience that if you can recover your costs within five (5) -- ten (10) -- 5 percent in any given year, you've nailed it pretty close. And so we're talking 10 percent in the winter of -- the year of '13/'14, so larger than we would have liked but in no way catastrophically large.

So moving on through my presentation, this graphic details all of the various deferral balance components that give rise to that $59.3 million for which we're seeking final approval. As we've been discussing all morning, we can see that the most material of those balances is the '13/'14 supplemental balance in the amount of $42.3 million recoverable from customers, and was a direct result of the winter of 2013/'14 and the market events that we've been discussing at length.

And the bulk of that balance, virtually all, is a result of differences between our average cost of supplemental gas purchases that winter at approximately eight dollars ($8) per gigajoule versus, for example, the four dollars and twenty-one cent ($4.21) average unit cost of gas embedded in the supplemental gas base rate that winter.

Now, the winter of '13/'14 was the result of a perfect storm, or confluence of a number of record and unforseen events. Number one (1), in terms of the records that we have in terms of weather in the form of heating degree days, it was the third coldest winter in the last fifty-five (55) years. There was only two (2) winters in our historical data base that were colder; the winter of 1995/'96 which was one-half (1/2) of 1 percent colder than the winter of '13/'14, and that's the year from which we derive our design peak day.

February 1st, 1996, the average daily temperature that day was minus thirty-eight (38) degrees. That gives you a sense of how cold that winter was. And the only other winter that was colder than those two (2) was the winter of 1978/'79, which was only 1 percent colder than the '13/'14 winter. And that's the winter from which we desri -- we derive our design winter calculation, so the worst case winter in our historical records. So very, very cold by any measure.

In addition, there's a thirty-two (32) year database of US and Canadian government data that tabulates heating degree days across North America, and then weights those heating degree days regionally based on the density of population in the various regions and their contribution to overall natural gas demand. And by that measure, it was cold across North America on a consistent, extended, and coincident basis such that it was the coldest winter in the entire government database, in terms of winter weather across North America. So Manitoba was not the only jurisdiction that experienced this record cold.

Compounding natural gas demand in the latter part of the winter was the fact that storage inventories were drawn down to record low levels, especially in the eastern half of North America. US government statistics, for example, showed that by March 31st eastern US storage inventory levels were drawn down to the lowest level since the records have been kept. And that's in spite of the fact that there's been a 14 percent growth over that period in total working gas capacity. So very, very low storage levels, which helped to compound the effect of weather on natural gas market demand.

And all of this was further compounded by the National Energy Board's complete deregulation of the pricing of short-term transportation services on the TransCanada mainline. So the effects that I just previously enumerated to this slide are what gave TransCanada the power to wield virtually unlimited pricing discretion on the mainline to the degree that it did during the '13/'14 winter.

We've discussed the use of variance accounts and Centra's PGVAs previously. And again, as I had said just a little earlier one could be forgiven if having recently come on the scene as it relates to Centra's regulation and look at the $42.3 million balances being catastrophically large. But as we showed in Figure 3.4 in our filing, the deferral balance at the end of the '13/'14 winter was by no means the highest that we've ever experienced.

That graphic shows, and now it has been adjusted or updated '14/'15 figures for our pre-hearing update filed with the Board recently. As you can see, since the dawn of the 21st century over the past fifteen (15) years of those periods where Centra ended the year with a total net cost deferral balance recoverable from customers, the winter of '13/'14 was above average, but by no means the largest that it's ever experienced. And that bottom dotted line represents the average of when balances were refundable to customers. So above average, but by no means the worst that we've ever experienced.

And in order to put the winter of '13/'14 in Centra's supplemental gas PGVA balance in the proper perspective, I think some context is important here. As I said, the winter of 2000/2001 was catastrophic by comparison to what we experienced in the winter of '13/'14. That winter started out extremely cold as well. November and December were rear -- near record cold.

That combined with the impacts that arose from a new pipeline, a export pipeline to the US from Alberta in the form of the Alliance pipeline, dramatically increased natural gas export capacity from Canada to the United States. So much so that prior to November 1st of 2000, there was an excess of demand from the US for Canadian gas, but a limited ability to satisfy that demand, such that gas in Alberta was stranded. And that drove prices down to fairly low levels and kept them there.

On November 1st, with the opening of the Alliance pipeline, Americans then were able to get all of the Canadian gas that they needed, so there was an excess of export capacity relative to US demand. And natural gas prices started on an inexorable march upward and spiked dramatically and quickly, such that by March 31st of 2001, Centra had accumulated more than a $120 million recoverable from customers in its gas cost deferral balance accounts.

That year, the majority of those amounts related to primary gas or gas purchased at Empress rather than supplemental gas supplies, but a commodity deferral nonetheless.

And I think it's important to note that that winter, Empress was not a safe haven. Every year takes on its own character, and the things that concern us take different forms. In the winter of 2000/2001, it was gas costs at Empress that were the concern rather than downstream supplemental gas purchases.

Now, Centra accumulated more than $120 million in recoverable gas cost deferral balances over that five (5) month period. But that was in spite of a cumulative annual bill increase for the typical residential customer in the one (1) year period surrounding that winter of nearly 73 percent.

So that's not a rate adjustment. That's a cumulative annual bill increase that was experienced by your typical residential customer in that one (1) year period surrounding that event.

In spite of that magnitude of increase, we still accumulated $120 million of unrecoverable --

unrecovered gas cost deferrals. This compares to the winter of 2013/'14 when we're talking about $42 million of unrecovered supplemental gas costs. And in the same annual period surrounding the winter of '13/'14, cumulative annual bill increases for the typical residential customer were a much more manageable 12.6 percent.

In fact, some very troubling figures notwithstanding regarding certain of Centra's individual supplemental gas purchases during the '13/'14 winter in terms of the average cost of those small amounts of purchases.

Centra's average cost of gas overall in the '13/'14 gas year is below average at four dollars and eighty cents ($4.80). So it's important not to get too overly fixated on the forty dollar ($40) gas purchases that were required to serve our market during the worst of those events and look at where we ended up overall for the year.

THE CHAIRPERSON: Was below average what?

MR. BRENT SANDERSON: It was below the average of Centra's overall commodity purchases in the thirteen (13) years leading up to the winter of '13/'14. So since the start of the 21st century, this graphic shows you what Centra's volume-weighted average unit cost of commodity purchases were in the thirteen (13) years leading up to the '13/'14 winter.

And over that period leading into that event, Centra's average cost of gas over that time was nearly six dollars ($6) per gigajoule. And in spite of a $42 million deferral balance which I have asked everyone assembled to keep in the proper context, overall, Centra's gas costs were below average, about a dollar ten ($1.10) below the previous thirteen (13) year average.

We believe that it's important not to lose sight of the fact that, dramatic events notwithstanding of the '13/'14 winter, natural gas was, did, and has since remained an excellent value for natural gas consumers in Manitoba.

Probably the best perspective to use in trying to evaluate where we are today relative to where we've been is to look at the total annual natural gas bill under normal weather conditions of a typical residential customer in Manitoba versus where we were a decade ago.

And today, in absolute terms, the annual natural gas bill of a typical residential customer in a normal year is 35 percent less than it was ten (10) years ago. And if we adjust that further for general price inflation over the period, it's a little more than half what it was ten (10) years ago.

And that's what this chart shows. The bar -- blue bar on the right shows the absolute quarterly approved bill of the typical residential customer, and then the bar -- pardon me, the blue bar on the left.

The blue bar on the right shows those same figures after adjusting for changes in the Canadian CPI. And the blue and the lines are trend lines showing the direction that we're going.

So in absolute terms, Manitoba gas consumers are in very good shape, and directionally we're on the right path.

In this application, in addition --

MS. MARILYN KAPITANY: Could we just go back to the 2000/2001 perspective? It's on slide 37. I just wanted to be sure I understand what you were saying on this slide in context of what we're talking about today.

So this is the one where Ms. Stewart had said that it started out November, December very, very cold, and then winter evaporated. And yet you're saying the prices went way up over the January, February, March period despite the fact that winter evaporated.

I'm just trying to understand how you came to the 120 million recoverable from consumers when this seemed to be a very warm winter as compared to what happened in '13/'14?

MR. BRENT SANDERSON: Well, and this is the point that I'm trying to make. Prices fell off after January, and so -- and so did consumption. What you see here is going into late summer the market was cognisant of the fact that the Alliance Pipeline was about to go into operation on November 1st.

So there was some anticipation in the futures market with respect to prices equalizing between the Canadian and US markets which would result in, all things being equal, increases in Canadian gas prices. So we began to reflect that in our primary gas rates in August because prices were already rising in the futures market, and that's the mechanism by which we adjust our primary gas rates, is we look at the futures markets.

So you saw an over 16 percent annual bill increase on August 1st of that year, and then the November 1 application for fri -- primary gas rates which would have been filed in October. We were continuing to see further price pressures, so we had another 10 percent plus bill increase on November 1.

November 1st, the markets, for want of a better term, literally exploded such that at Empress in January of that year the price for base load gas, so a base load fixed price for gas at the monthly index at Empress was over thir -- was nearly thirteen dollars ($13) a gigajoule for the entire month and daily swing prices went almost to seventeen dollars ($17).

So while things began to cool off already in -- in the latter part of January, the damage was done by then. This -- this accumulated in the space of about two and a half (2 1/2) months. So, as we said, in spite of by the following May 1st having passed on accumulative 73 percent annual bill increase to residential customers, it was still that much insufficient to reflect the increases in costs that we were experiencing such that on top of that we accumulated $120 million of prior period gas cost deferrals.

And like we have proposed with the '13/'14 supplemental gas PGVA, Centra, Manitoba Hydro sought to recover those moneys over a two (2) year period to smooth the impacts on customers. But in spite of all those efforts, you can see the rate shock that customers experienced.

So this is the perspective that we brought to the table in the winter of '13/'14, having been through this and seen the effects of rate shock and what it does to customers and the perceived value of gas. So comparatively, there was not an emergency, as we understood it, given our historical experience in the business. Higher than we would have liked? Yes, but no my -- by no means a disaster.

(BRIEF PAUSE)

MR. BRENT SANDERSON: Now with reference to our base rate -- our non-primary gas base rate adjustments that we are seeking for November 1, 2015, on an interim basis. As reflected in our pre-hearing update, Centra is forecasting its total annual gas costs for the 2015/'16 gas year at $211.12 -- .2 million. Of that amount, approximately $80.8 million is comprised of non-primary gas costs which are the subject of this proceeding.

$17.5 million of that amount is related to supplemental gas costs, 61 million related to transportation costs on the various pipelines and

Centra's storage assets, and 2.3 million relating to unaccounted for gas on Centra's do -- distribution system, so that amount of gas that we bring into our distribution system, the difference between that and what ultimately is billed to customers at the end of the day.

Now, if we were to leave our current non-primary gas base rates in place and not adjust them on November 1st, 2015, and apply those to our load forecast for that period, supplemental gas rates would over-recover our forecast supplemental gas costs by approximately eight hundred thousand dollars ($800,000). Therefore, we're seeking to reduce the customer supplemental gas base rate by a total of that amount.

Conversely, current transportation base rates, if left in place, would under recover our forecast upstream transportation costs over that same period by approximately $12.9 million. While there will be very, very minor and virtually imperceptible changes in our distribution rates as it relates to unaccounted for gas. Rounded to the nearest hundred thousand (100,000), it doesn't even total to an amount that registers. So virtually unchanged from the distribution base rates in place right now.

Again, to provide a little bit of perspective on not customers' annual bills in this case, but on Centra's overall forecast gas cost. In the sixteen (16) years, since the beginning of the 21st Century, only two (2) years have seen lower overall natural gas cost for Manitobans relative to what Centra is currently forecasting for the 2015/'16 gas year.

One of those two (2) years, the '11/'12 gas year, the load total was in large part the result of the warmest gas year that Centra ever experienced in the past fifteen (15) -- fifty-five (55) years, and the commensurate lower demand for natural gas which dragged down our overall gas cost.

Looking at absolute terms compared to sixteen (16) years ago, Centra's currently forecast 2015/'16 gas costs are merely 60 percent lower today than they were sixteen (16) years ago. And applying that same adjustment for CPI to those figures, about a third of what they were fifteen (15) years ago as this chart shows.

So members of the Board, all things considered and put in the proper perspective that it deserves, there has seldom been a time in the last generation where it's been such a good time to be a natural gas customer in Manitoba. In speaking for myself, I don't think there's a better -- a better time in my twenty (20) year career in -- in the history -- in the years that I've been involved in the industry.

So with that, I'd like to close and pass onto Mr. Barnlund.

THE CHAIRPERSON: You know, I'd prefer that we just finish this up and then we can do something else this afternoon, so if you don't mind I -- it's a bit later than usual but let's -- like to go on.

MR. GREG BARNLUND: Cer -- certainly. I have a few slides, and -- and then we'll be done so. All right. Thank you very much. I'm going to walk us through basically the rate setting and the bill impacts we're talking about in terms of the recovery of both our forecast gas cost and our deferral account balances in this particular filing.

Just to touch briefly on the approvals. Again we're looking for approval of -- of new -- supplemental gas transportation distribution rates to be effective November 1 of this year. We will -- also looking for approval of the recovery of the outlook balances of the deferral accounts, and -- or, sorry, the balance of the deferral accounts to outlook to October 31st, and the forecast gas cost as referred to by Mr. Sanderson.

We also are looking to seek a continuation of the current temporary rate rider treatment for large volume customers, specifically the interruptible customers that may migrate to firm service, or other customers that may migrate with respect to transportation service and have done so post May 1, 2014.

We're also seeking some final approvals of interim orders of rates from August 1st of 2013 in Order 89/'13, Orders 89/'14, 132/'14, and 12/'15. We'd like final approval on those. And final approval of the gas costs in the two (2) gas years that have closed, '12/'13 and '13/'14 gas year.

So with respect to that, we have other approvals that are set out in -- I think it's Appendix 7.1 in terms of interim approvals that we would like to have finalized in terms of franchise applications in that regard.

I just would like to, I think, walk us through a period of time here and talk about the bill impacts, and talk about -- a little bit about our rate setting methodology here because, to me, I think that's very key to keep in mind. And what I'm representing here in this slide is -- is the typical residential customer -- the bill impact to a typical residential customer quarter by quarter as filed in our Application since we received approval of rates from the last General Rate Application, so from August 1st of '13 through to our proposed rates of November 1 of '15.

And from my perspective, I think that this is -- this -- this is a picture of success in terms of rate stability, and speaks to the use of both deferral accounts, rate riders -- and rate riders in terms of being able to manage the volatility of market prices and of gas costs to customers, and to be able to again provide them with reasonable stability in terms of their rates and in terms of their bills.

So if we look at it, the -- the range of -- of annual bills re -- represents from, I think, seven hundred and sixty dollars ($760) a year August 1st of '13. If we look at sort of the peak that we have in this chart, that was with the implementation of our supplemental gas recoveries of the -- of the beginning of the recovery of the supplemental gas costs for the '13/'4 -- '14 year when we came in in November 1 of '14, with rates. That bill impact to customers was a little over nine hundred dollars ($900) a year.

Since then gas costs, and again a lot of this is -- is influenced by changes in terms of commodity costs that are reflected in changes in primary gas price. But since that time, basically the annual bills have dropped down to the eight fifty (850) to eight thirty-five (835) range. And if we took a look at what we're proposing in this particular rate filing for rates for November 1, and if we calculate it out, an annual consumption at 2,374 cubic metres, the impact would be about eight hundred and sixty dollars ($860).

And that will not be the exact number we're representing in our bill impact tables, because we've updated the bill impact tables for more recent load forecasts. But I wanted to present this on an apples-to-apples comparison for this particular chart.

MR. NEIL DUBOFF: So just to be clear that eight sixty (860) you just said would take into account the rates that you're asking for, as well as the $36.1 million. It's both?

MR. GREG BARNLUND: Yes, that's asking for the rates we're proposing in this application for these recoveries. It does not include any potential change to primary gas itself for November 1.

Now, bearing in mind that we would be filing that with the Board around October 13th. Our anticipation right now is that there wouldn't be a significant -- a significant change to consider in terms of primary gas itself for November 1.

MR. NEIL DUBOFF: But this picks up the thirty six point one (36.1) and on a one (1) year amortization?

MR. GREG BARNLUND: This -- this does. This replaces --

MR. NEIL DUBOFF: The eight sixty (860), I mean, that you said.

MR. GREG BARNLUND: Yes. So at eight sixty (860), eight hundred and sixty dollars ($860) a year, that takes care of the existing rider being taken off and the new rider being put on to recover the remainder of the money over a twelve (12) month period. Yeah. Yeah.

MR. NEIL DUBOFF: Did you -- have you done any calculations if we did a two (2) year amortization? Do you -- is there any sense of what that might be?

MR. GREG BARNLUND: We haven't done that at this point in time. We were -- of course, we had originally proposed a -- a two (2) year amortization last November --

MR. NEIL DUBOFF: Yes.

MR. GREG BARNLUND: -- when we put those rates forward. But we haven't recalculated this particular filing for that.

THE CHAIRPERSON: The last time I looked gas prices were pretty soft, so we could be facing -- we -- we could have lower rates in November, couldn't we?

MR. BRENT SANDERSON: If I might just point out pretty soft historically speaking, but not significantly softer than are reflected in current primary gas rates.

THE CHAIRPERSON: Okay. So I'm looking at the weather reports forecasting high temperatures in the US, upper Midwest, probably Manitoba as well. We set rates November 1.

We could be facing -- if we have a -- a mild winter, what -- what does it mean? What does it mean in terms of the PG -- the purchased gas variance accounts?

MR. BRENT SANDERSON: In terms of the disposition of those accounts?

THE CHAIRPERSON: No, I -- I mean, what -- what happens? Are we going to be in a situation in say January where we are accumulating a surplus in those accounts if it's a mild winter? Or the opposite?

MR. BRENT SANDERSON: Well, given that we have $36.1 million to recover from customers, warmer than normal weather and lower than forecast consumption would operate conversely, in that you would likely under-recover those amounts. To what extent, no one can say at this point.

We were having a bit of a deba -- a debate about the efficacy of weather forecasts. I spent a lot of time during my years engaged in load forecasting looking at weather data. And it's been my experience that a weather forecast beyond three (3) days out has no predictive value whatsoever.

So there's no response I can give you in terms of what might happen. If it's warmer than normal, and lower than forecast consumption we wouldn't re -- recover as much of these monies as we had originally forecast. To what extent, we can't say. Conversely there's innumerable things that could happen in and in many inconceivable ways prices could be higher. Consumption could be higher. If consumption's higher we may over-recover. But that's the role of the deferral account. Any residual will be captured in that account and we would bring that forward to this Board for disposition at a future proceeding.

But in terms of what's going to happen this winter regards to weather, natural gas prices, the only intellectually honest conclusion that I can give you is no one really knows.

MR. NEIL DUBOFF: So, but, Mr. Barnlund, if -- if you could, on the same basis as the calculations were done on that slide number 49, if it's not too difficult, just to let us know so we have the information on what it would take if we took half of that thirty-six point one (36.1) and put it in this year that you're showing and the other one in the -- in the year subsequent to that.

So just a sense as to what kind of number we're talking about to the average consumer.

MR. GREG BARNLUND: Well, we could undertake to run the analysis and amortizing that over a twenty-four (24) month period instead of --

MR. NEIL DUBOFF: Just -- just so we have a sense of what it's going to do to the consumer.

MR. GREG BARNLUND: Yes, we can do

that, yeah.

--- UNDERTAKING NO. 1: Centra to run analysis and amortize it over twenty-four months if half of thirty-six point one (36.1) was put in this year and the other half in the year subsequent to that

MR. GREG BARNLUND: So I'd just like to take a look at the impacts we're proposing in this application. And I'm going to look at it in two (2) phases. I'm going to look at a base-rate change, and a base rate does not have the riders applied to it.

So if you look at the base rate, it's looking at our forecast gas costs, and it's providing or it's presenting a rate that is reflective of what the forecast is for the gas costs forecast for the upcoming year.

Separately then, we'll talk about rates that are actually going to be presented to customers on their bills. That's when we introduce the rate riders onto those rates.

So if we look at the base-rate impacts across our customer classes, the typical residential customer is in the 2.2 -- 2,200 cubic metre category, if you would, so at the top of our chart, the middle line.

The base-rate impact would be about a twenty-two dollar ($22) a year increase to that customer, which is about a 3 percent change.

The other customer classes are faced with different levels of impact, and that's because their usage characteristics are obviously different than the usage characteristics of a residential customer.

So that's why you're going to see a range of impacts that, for example for the high-volume firm customers, ranges from 2.5 to 4.7 percent. And that's because of basically the way that they are using the system and the way those costs are being allocated to them.

I'm going to then move to the final or our -- our billed rate schedule here, which is what we really present to customers on their bills.

And so this is the base rates which represent the incre -- or the forecast for the upcoming gas year, and then layering on the rate riders to be able to recover or refund the balance -- the account balances that we've talked about.

The impact for the typical residential customer at 2,200 cubic metres is an increase of about thirty ($30) a year, or 3.8 percent.

You'll notice that there are actually some decreases that show up for some of the other customer classes. And that's as a result of riders that are refunding money to those customers. And that's -- there's a number of moving parts in terms of the rate calculation.

It's not necessarily intuitive when you look at it. First of all, there's changes of load. So overall, while we may have relatively stable load in terms of the total system, if we have customers that are migrating from one class to another, for example, interruptible customers are migrating to firm service, well, that represents a change that we pick up in our subsequent rate filings.

And so what happens is, in doing so, that -- the course of that migration over a period of time will result in recoveries being greater or lesser for certain classes than we would have thought when we put those riders in place to begin with.

And that results then, when you

reallocate the deferral account balances out in a subsequent period, in some cases you end up refunding money to the -- these classes. In other words, we would have recovered more money from the high-volume firm class in a previous period because we moved 2 1/2 percent of our load from the interruptible customer class to the firm class.

So there's more customers in there that were paying those rates through that period of time. We actually would have over recovered from those particular customers in terms of certain of our rate riders and our -- for example our transportation or distribution PGVA.

MR. NEIL DUBOFF: For -- for the '15/'16 year, could you not adjust your rates to the high-volume customers so that you're wiping out any increase to the residential customers?

MR. GREG BARNLUND: Well, that would be a introduction of a cross-subsidy between customer classes. And --

MR. NEIL DUBOFF: It'll turn out that way, but it doesn't have to -- you know, you -- you can frame it that way. But it could also be that you just change your -- give different rates.

MR. GREG BARNLUND: The long-standing

I guess practice and I think the policy in front of this Board has been that we would be attempting to set rates as close as possible to unity -- in other words, recovering 100 percent of the allocated costs from each customer class, no more, no less.

On the gas side of the business, we have no zone of reasonableness. We set rates at unity. So the amount of cost that's allocated to the residential customer class is going to be borne by that class. The amount of cost that's -- that's allocated to the high volume firm customers will be borne by that class. And there is no notion of cross-subsidy between those two (2) customer classes. That -- that's our longstanding perspective and that's been the perspective that has been present here in Manitoba.

And this really just reflects -- or describes a little bit more in terms of the bill impacts. The bill rates, obviously, as I said, reflect both changes to base rates and the rate riders. And the -- the -- I guess, the -- the step that we're going to go through here is that we're going to have a rider that is going to terminate October 31st, and we're looking to replace it with a supplemental gas rider beginning November 1st.

Again, we had proposed it be recovered over a twelve (12) month period. And we'll undertake to look at what that recovery would be over a twenty-four (24) month period.

So we did experience an amount of customer migration away from the interruptible customer class through this period of time. And so through the '13/'14 year we had a number -- approximately ten (10) interruptible customers that chose that they were going to require firm service instead of staying interruptible.

And I imagine that each of them made this decision on their own -- you know, on the -- the merits of -- of the economics of it. But I know that -- that, you know, when you look at the amount of curtailment that we experienced through the '13/'14 winter, the interruptible customers paid probably about $6 million in alternate supply costs. In other words, they were curtailed because of the reasons we have spoken here earlier. And when they're cur -- curtailed they have the option of acquiring ultimate supply service from us; many of them chose to do so.

And through that period of time, those costs accumulated to be about $6 million. They paid those costs at -- at -- you know, in realtime. The incurred those costs in realtime and they paid them in realtime. And I think at that point in time, there was a decision that they would have been carefully examining whether it was really -- whether the exposure to the market pricing that exists when they're curtailed is sufficiently compensated by the amount of discount they would receive in their rates as an interruptible customer, and ten of them chose to move to firm service.

MR. NEIL DUBOFF: Are most of the interruptible customers on diesel?

MR. GREG BARNLUND: For the most part, there may be one (1) customer that has got a propane air backup, but the rest of them would be fuel oil.

MR. NEIL DUBOFF: So the -- just from an environmental perspective because I know that's again one (1) of the pillars, having them uninteruptible may have a greater en -- environmental impact in Manitoba?

MR. GREG BARNLUND: If -- if they chose to burn their alternate supply as opposed to acquiring --

MR. NEIL DUBOFF: Natural gas?

MR. GREG BARNLUND: -- natural gas to do that. Now, bear in mind that some of the customers that have elected to say on interruptible service are facilities that are required to have fuel oil backup anyhow, in other words, your major --

MR. NEIL DUBOFF: Hospitals.

MR. GREG BARNLUND: -- hospitals, you know, tho -- those types of institutional occupancies. They're likely required to have a backup energy source available to them in the event of some kind of a similar -- specific emergency.

So for them, it was an evaluation, if they had the backup fuel available to them, you know, did it make sense for them to be an interruptible customer or firm customer. And -- and over the years, that was probably -- it made sense for them to stay interruptible. But with the marketing -- pricing conditions that we see these days, those circumstances, I think, are far different for those customers.

So in any event, if a customer had been an interruptible customer through that period of time when we had this accumulation in the PGVA, the interruptible customers were basically paying their own way through that period anyhow, so they weren't contributing in any great extent to the buildup of that purchase -- that supplemental gas purchase various account.

So they had funded their own natural gas purchases for that period to the tune of about $6 million. And so if -- if a customer subsequently after that winter made the decision to move to firm service, we didn't view it reasonable that they would then participate in the cost recovery of supplemental gas that was caused by the firm customers while they were paying their own way as an interruptible customer through that period of time.

So we wanted to specifically introduce an accommodation on a temporary basis for those customers. Now, this is while we're still recovering the supplemental gas cost. We wanted to make sure that they were not being double-charged. That they were not being required to fund part of the firm customer's contribution to the -- to that supplemental PGVA buildup.

And so we tracked those customers. Essentially if they became a high volume firm customer, we would adjust our billing so that they were paying the interruptible supplemental rate and not the firm supplemental rate for the -- for the future period.

Similarly we had an instance where a

customer was on firm service, and decided to go to transportation service. In other words, become a T-service customer and therefore they would be completely responsible for their own upstream transportation and -- and acquisition of gas. All they're looking at from -- from Centra Gas or Manitoba Hydro is the delivery of the gas on the distribution system.

So that customer was a firm customer through the '13/'14 winter, and that customer consumed supplemental gas. And that customer contributed to part of the build up of costs of the supplemental PGVA. And so was it fair then to release them of that obligation when they moved to become a transportation service customer because as a transportation service customer you would net -- not see any upstream charges -- upstream gas charges any more on your bill from Centra Gas.

So we had proposed that they be required to pay a rate rider, which is the equivalent firm rate rider to recover the supplemental gas costs that they helped contribute to through the '13/'14 winter.

So those are really the considerations that we had -- had adopted, or had proposed in the fall of the last year, and we seek a continuation of those at least until -- obviously until we get the supplemental gas -- purchased gas variance accounts cleaned up.

So I -- I wanted to bring us back to this thought because this is a message that we put on our bill -- our bill inserts when we change rates four (4) times a year. And I think it really explains a lot of what we've talked about here this morning in terms of the use of the deferral account mechanism, and using a quarterly rate setting mechanism, and looking at how we amortize those costs to customers in their rate riders. And we say to all customers:

> "Quarterly adjustments help reduce the risk of large one time adjustments to Manitoba Hydro customers."

And if you reflect back to Tab 2 where we had this enormous spike in pricing through a two (2) month period, if you're not using some form of -- of combination of deferral account and PGVA disposition through rate riders, what -- what would you be doing with the customer in those particular circumstances? You would be forced to be dramatically increasing rates only to be dramatically decreasing rates thereafter.

And I would submit that the balance between price transparency and rate stability is also -- has to take into consideration that what -- what do we really mean by price transparency? If we're in the middle of March of 2014, and if prices are forty dollars ($40) a gigajoule, what does a customer take from that? Does that mean my gas costs will be forty dollars ($40) a gigajoule from now on in?

They have no sense of the volatility of that market. And so the other element of a deferral account, and -- and using a rate rider to be able to recover those over some reasonable period is to be able to take, if you would, the static and the noise out of the movement of the market price and relate it in a much more understandable way to customers.

Because as we're going through this period of time where you're seeing, you know, some very, very significant pricing activity happening in the market, if that price signal is being transmitted directly to customers at that point in time I would suggest you're going to have more confusion than anything else, and would people abandon gas service entirely if they misunderstood what -- what the market behaviour was, and if they reacted and overreacted to it? So -- so in us reacting the way we did to it we employed, you know, as a prime consideration the stabilizing aspect of rate -- of our rate setting mechanism.

And so that's why -- you know, when we look at that graph here that shows a range of -- of annual bills between eight hundred and sixty dollars ($860) and nine hundred and twenty dollars ($920) a year, I think we've done the consu -- gas consumes of Manitoba a great service in terms of being able to stabilize bills, and stabilize rates for them, and not to create a panic if you would in the marketplace by having extreme dislocations in terms of our rates to customers, and therefore bills.

If I could return to the presentation, Diana? Thank you. So we go on to say we lessen the impact of volatile natural gas prices. Well, it's -- there's no -- there's no con -- there's no misunderstanding. There is volatility in the gas price market. But we -- we also -- the way our portfolio and our rates are structured, as we say over 90 percent on a normal year of our gas is primary gas, which we're using storage in the summer to be able to basically purchase in the off-season, to be able to balance the costs, so that we're not completely exposed to winter pricing, right?

By reducing that volatility you reduce sort of the possibility of panic in your customers when that happens. So it's a combination of putting gas in storage, buying it through the off-season, and putting it in storage, and withdrawing to use it in the winter. That stabilizes our rates, because our primary gas rates are balanced between -- with the inventory costs of gas and storage, and what we purchase in the -- in the -- on -- on forward market supplies.

So -- so the deferral account mechanism then, it -- it also serves to be able to stabilize and reduce the amount of volatility that we have. Ultimately customers also have the option of using the Equal Payment Plan. I mean, that -- that is, you know, what we would suggest to customers between use of Equal -- Equal Payment Plans and energy conservation, because those are our two (2) -- we keep coming back to those two (2) key themes for customers, the importance of conserving energy. And if -- if you, you know, want to avail yourself of it use the Equal Payment Plan to be able to smooth your cash flow.

So as a last slide I just wanted to

show a comparison of the experience in Manitoba in terms of Centra's bills over a period of time, with four (4) other utilities. And -- and so I've got information that was taken from publicly available sources. In other words, we've got Enbridge's quarterly rates here, or quarterly bills. We have Fortis BC's quarterly bills, and SaskEnergy compared to our own. And Centra's is the blue dotted line on the -- following the bottom of the -- of the chart here.

So what we can see is that in other jurisdictions there has been a reaction as well in terms of customers' bills to the market conditions that have been experienced over this period of time. And if you look at it, I think that what you see is that Centra and the customers -- consumers in Manitoba, comparatively speaking, have seen far greater stability in terms of their quarterly adjustments and impacts on them than customers in other jurisdictions.

And I just wanted to, you know, note that these other jurisdictions, certainly Enbridge and Fortis BC, also set their rates on a quarterly basis, so they have a quarterly mechanism similar to our -- to our own. However, the circumstances for those utilities has obviously been different, because it's relating it to different bill impacts for -- for residential customers.

So I just wanted to close on that fact, to say that I think that we have -- we've -- we've guided the ship through the some fairly turbulent seas here over the -- over a period of time. And that we've been able to do so without unduly creating bill impacts to customers.

THE CHAIRPERSON: Thank you. With that I think we'll recess for forty-five (45) minutes, so I propose that we resume proceedings at twenty (20) after 1:00. I'm assuming that's enough time for people to have dinner -- lunch rather. Twenty-five (25) -- twenty (20) after 1:00. Thank you.

--- Upon recessing at 12:35 p.m.
--- Upon resuming at 1:21 p.m.

THE CHAIRPERSON: Good afternoon. I believe we are ready to resume the proceedings of today. Mr. Czarnecki, please.

MR. BRENT CZARNECKI: Thank you, Mr. Chairman. I do have one (1) last question I'd like to pose to Mr. Rainkie, and that will conclude Centra's direct evidence. So with your permission, I'll go ahead.

CONTINUED BY MR. CZARNECKI:

MR. BRENT CZARNECKI: Mr. Rainkie, in the Board's Interim Order No. 12/15 on Centra's Interim Application for Non-Primary Gas Rate Riders, the Board stated, and I quote:

> "In the upcoming Cost of Gas Application, the Board expects Centra to consider whether a portion of its retained earnings which resulted from the cold weather should be used to reduce the negative impact on customers from the further recovery of the supplemental gas PGVA."

Mr. Rainkie, could you please describe how Centra has addressed the Board's expressed expecta -- expectation and Centra's conclusion?

MR. DARREN RAINKIE: Sure. Good afternoon, everybody. I'm going to give you the headline first. I'll give you our position on the matter, then I'll fill in the details afterwards.

It'll -- it'll take me a few minutes to go through, but just please bear with me. I'll -- I'll flesh out our position on this.

So Centra's position on this issue as outlined on page 5 of Tab 2 of the Application is that it's not appropriate to offset prudently incurred gas costs, regardless of the circumstances, with the financial reserves of the Corporation.

Centra took this request of the PUB seriously and engaged Mr. Mark Drazen of Drazen Consulting for his independent expert testimony on the issue which you can find at Appendix 2.2 of the original Application. Mr. Drazen's expert testimony supports Centra's position.

So in going through this and understanding our position, I think it's first important to understand or to think about the nature of gas costs. So gas costs are determined either by the competitive wholesale natural gas market or by other regulatory agencies such as the NEB in the case of transportation tolls.

Virtually all of these gas costs are outside of the control of the local distribution company, which is just a -- a nice name for a gas company like Centra.

As with other market-traded commodities, the price for natural gas is largely unpredictable and may exhibit significant volatility over particular time periods.

In addition, the costs of acquiring, transporting, and store -- storing natural gas is generally the most significant component of a gas distribution company's overall cost of operations or revenue requirement, as we call it in this proceeding.

For instance, in Centra's case, for 2015/'16, the total cost of gas represents appox -- approximately 60 percent of its total revenue requirement, even in this low gas-cost environment that we're currently in. When I think back to years ago, I think the gas costs may have been upwards of 75 percent or more of Centra's total revenue requirement, or even -- even perhaps higher.

So due to the magnitude and variability of gas costs and the facts that -- fact that they are outside the control of the distribution company, they represent a significant financial risk to the utility. We're not talking about a small portion of -- of costs that are moving around in a fair -- fairly stable manner. There is a lot of financial risk with respect to gas costs.

So how has regulatory practice in North America evolved to deal with this financial risk ensure the lowest cost to customers in the end? So to deal with this issue, gas costs passthrough mechanisms have been accepted and applied across North American -- in the North American gas industry. This fact has been confirmed in Mr. Drazen's expert testimony. I -- I don't think that's a dispute at the hearing.

So what are the features of gas cost passthrough mechanisms? The key feature is that the supply price risk is borne entirely by the customer. Distribution companies do not mark up or make a profit on gas costs, but gas costs are flowed through to customers on a dollar for dollar basis use -- using mechanisms similar to the PGVAs. They might be called something different in another jurisdiction, but the functioning of them is similar.

The return or net income of the distribution company that is set by their regulatory body is intended to compensate only for the risks inherent in the distribution of natural gas, not the supply price risk.

So why does the cost -- gas cost passthrough regulatory approach make sense and result in the lowest long-run cost for the customer? So without the gas cost passthrough mechanism, distribution companies would face an extremely high level of risk, and would require customers to compensate for that -- for assuming that risk through a significantly higher return or net income.

The universal acceptance of gas costs passthrough mechanisms is proof that North American regulatory bodies have all come to the same conclusion. It is more cost-effective for customers to assume the supply price risk over the long term than to pay much higher rates of return to the Utility to assume this risk.

Stated differently, the insurance premium to the customers would be so high for the Utility to assume the supply price risk that the customer is better off over the long run to self-insure this risk.

In some years, gas costs will be lower than forecast resulting in PGVA refunds. And in some years gas costs will be higher than forecast as was the case in 2013/'14, resulting in PGVA recoveries. But over time, this will balance out for the customer and is -- is the most cost-effective approach rather than paying an unacceptably high insurance premium to the Utility.

So what are the risks of Centra cust -- to cust -- Centra's customers if the PUB was to decide to use financial reserves to offset supplemental gas costs? While Centra's financial reserves in the form of retained earnings -- that's what they're called on our balance sheet -- are used to ensure the future rate stability of distribution rates for customers, they are not used to provide a return to Manitoba Hydro, or to pay dividends to a shareholder, or to enrich a share price.

They remain in Centra for the benefit of the customer for rate stability. If the financial reserves are used to offset supplemental gas costs, Centra would have to replenish these financial reserves through future general rate increases. It would have to increase the net income that it has recovered through rates to assume the supply price risk.

This would be a fundamental change to Centra's regulatory construct, and would move the PUB's regulation of Centra to be an outlier in North America. More importantly, this would impose higher costs on Centra's customers over the long run, and would leave us without a workable regulatory scheme on the gas side of the business.

This would require us to go back and rethink how Centra is regulated. This would also result in unnecessary uncertainty in costs for both Centra and its customers. There is also the regulatory principle of fairness to consider.

As Mr. Drazen observed in his independent expert testimony, the PUB should not look at the 2013/'14 winter and resulting supplemental gas costs in isolation. While the 2013/'14 winter was one of the coldest on record and result in a significant PGVA recovery, there have been a number of years in recent history with warmer than normal weather with a significant PGVA refund to customers.

There was no application by Centra or a suggestion by any other parties at the hearing that in these warm years Centra would recoup the losses that result from this warmer weather. This long-standing regulatory mechanism has been fairly applied by both the PUB and Centra for decades.

In fact, if you look at Mr. Drazen's evidence on page 11, Table 1, you'll find that over the last ten (10) years Centra's contributions to financial reserves or net income has averaged around the $3 million target that has been previously determined by the Public Utilities Board.

While 2013/'14 had a significant net income, there have been many years of losses due to warmer than normal weather. And once again, these balance out over time and result in a fair and reasonable regulatory framework for customers.

So in conclusion --

MR. NEIL DUBOFF: Mr. Rainkie -- Mr. Rainkie, I -- I guess where I'd like you to speak to -- and thank you very much for that answer. It -- it deals with a lot of what I've been thinking about. But -- but we have a situation where, as you correctly say and I agree with, looking at '13/'14 in and of itself as an aberrant year really shouldn't be looked at.

What I do look at though is $36.1 million that's accumulated in this account because that's a number, however it was accumulated -- because it -- really that number takes into account one (1) year of surplus and two (2) years of -- of charges there, expenses, negatives, so I just look at the number 36.1.

And then, although I really do respect and I like the idea of keeping the distribution separate from the issue of -- of the supply -- the cost itself, we have a retained earning that is higher than -- as a percentage than the amount that typically this Board has -- has been looking at as a percentage of retained earnings for -- for the Company.

I -- I believe that figure, if I -- if I'm not mistake, is about 30 percent has been the target. And right now, I believe, if my figures are correct, it's about 35 percent. So you've got a difference there in the retained earnings from what this Board has ordered in the past which -- which is a number -- you can translate that 5 percent to a number. And the I look at the fact that there's $36.1 million that's being asked of the consumers of thi -- of this Province.

So what I'm asking myself is: How do I say to Manitobans when -- when we -- the Public Utility Board has -- has said that the target should be 30 percent as -- as for the retained earnings and I have an accumulated shortfall of 36.1, how do I say to people in Manitoba that I shouldn't be offsetting one (1) against the other?

MR. DARREN RAINKIE: Well, there's a -- there's a number of ways to respond or a number of angles on that. First of all, the accepted target for a gas distribution company is more in the range of 35 to 40 percent equity. Centra, for many decades, had a

40 percent equity ratio.

And if you look at some of the information that we filed, and I think it's in the book of documents prepared by PUB counsel, that range is clearly in the 35 to 40 percent range. Where the 30 percent comes from, I -- I --

MR. NEIL DUBOFF: I believe it's an order.

MR. DARREN RAINKIE: Well, I -- I don't recall how we got to that, sir, because, quite frankly, the discussion on that was about five (5) minutes. It was asked of a witness who's not an expert in rate of return and -- and capital structure, Mr. Matwichuk. He's a general revenue requirement witness. There was not a notice at that hearing of -- of that was going to be an issue. Centra had no opportunity to bring evidence to inform that, so how we got to the 30 percent I don't -- I don't know.

I -- I think that when you look at the risks of a -- of a gas utility, and the Board -- the PUB has expressed that they want to look at it on a standalone basis. If you look at the Company from a standalone basis you would have a 35 to 40 percent equity ratio.

MR. NEIL DUBOFF: And I accept -- I

accept what you're saying, that the standard for the industry should be 35 to 40. But today I'm sitting here, and there's -- there's an order that says 30. And to the extent that the Company wants to come forward with more than one (1) witness and say that it shouldn't be 30, it should be 35 to 40, I -- I'm certainly open for that, but -- but the order is there.

MR. DARREN RAINKIE: Well, sir, what would -- happens next year if we had a $25 million reduction in -- or -- or a refund of a PGVA's? Would we give that back to the Company? Like, I -- I'm having a hard time that we're looking the $36 million in isolation. The charts that were provided this morning I saw a PGVA re -- refund of probably in the order of 20 or $25 million a number of years ago.

So I'm having trouble as to why we would look at this one (1) particular year and -- and have that attitude in this year versus the other years where it was warmer where there was nobody coming at us saying, well, you know, your retained earnings are below your target, why don't we top it up. I mean, it's -- we're --

MR. NEIL DUBOFF: Mr. Rainkie, I don't have an -- I truly don't have an attitude. I really don't have a predisposition. All I'm trying to do is get the information. From what I have, I really don't have a perspective that says it shouldn't be the 36.1 that's recovered over one (1) year or two (2) years or five (5) years. I don't have a perspective on that. I'm simply trying to gather the information so that I can work with the other panel members here to come up with a decision.

I really don't have a -- a predisposition. And none of my questions, I -- I want to let anybody think that I have a predisposition one (1) way or the other. It may be that the decision is to recover the entire thirty-six point one (36.1) in one (1) year. I'm just trying to get all the information so I can make my decision with the other panel members.

MR. DARREN RAINKIE: No, that's -- that's understood. But I guess what I'm encouraging the Board to do is look at this over the long run and look -- take the broader context. We have risks on the distribution side. We have aging infrastructure risks, for instance, and we talked about this quite a bit at the electric general rate application that just ended. But -- but we have that same issue on the gas side of the -- of the business.

So, we have to be careful that we're not looking at one (1) point in time and reducing the retained earnings, and then just having to come back and replace that with general rate increases. I'm not sure how that -- that helps the customer, you know, in the end. And when you look at this, we have, you know, $150 million in non-gas costs. I mean, you kind of average the income over the last number of years. It moves around by, you know, 5 or $10 million on either side of it.

If you looked at Mr. Sanderson's chart on gas costs and you draw a line through the average of it, it's probably something like $300 million just for -- for ease of calculation. You know, if those costs were moving, let's say 20 percent, and I -- I note I'm not a gas cost analyst. I'm not sure what their variation -- the folks down the line could probably tell me to the fourth decimal place.

But if -- if you just did a calculation like that thir -- $300 million of it was moving around 20 percent, you're ta -- you're talking about $60 million a year. You're talking about something that, if we took this approach, could wipe out your retained earnings in one (1) year, double it in the next. I mean, that's the very reason that you see -- I think you have to ask yourself: Why do we have these pass-through mechanisms across North America? Are all regulators wrong? Have all three hundred (300) companies got to the wrong system?

And I -- I think the reason it's there is that the system makes sense. We have the retained earnings on the distribution side for a reason. It makes sense in the long run that gas costs are passed through to the customer, that they self-insure for that. No more, no less. But if we -- if we look at one (1) year and overreact to it, what tends to happen is we have that regret factor. That we come back later and say, Boy, I wish we hadn't -- you know, we hadn't of done that, because it doesn't work for customers over the long run.

I think right now, if you look at the $3 million net income target, largely the average over the last ten (10) years, although there's, you know, ups and downs has been that. So it's -- I -- I think it's worked reasonably for us. We've built retained earnings as our -- as the size of the company has increased. So proportionately I think we're -- we're pretty good there.

And I think the calculations we did on the record, which I'm sure we're going to go through this afternoon if I understand the book of documents, show that we would fall even below the 30 percent, you know, ratio of equity if we were to swap out the retained earnings for gas costs, but -- but I don't think that's an appropriate thing to do for the reasons I've just stated.

(BRIEF PAUSE)

THE CHAIRPERSON: Thank you, Mr. Rainkie. Mr. Czarnecki, are you done? You -- you don't want to finish your statement, Mr. Rainkie?

MR. DARREN RAINKIE: I've probably said enough already, sir. I mean, I -- I think, as -- as you know, that's my style, so. I think -- I think the issue will mature as we go through the cross-examination. So I'll -- I'm certa -- I'll certainly pipe up if I have other thoughts.

THE CHAIRPERSON: Thank you.

CROSS-EXAMINATION BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: Thank you. And good afternoon, members of the panel. I -- I noticed that the Chairman mentioned that we can do something else this afternoon, and he graciously didn't mentioned that it was my cross-examination.

My name is Sven Hombach. I'm acting as counsel for the Public Utilities Board in this proceeding. And my questions are going to be directed to Centra. They're not directed to individual members of the panel. I may think that one (1) panel member is the most appropriate person to address them, but by all means if you'd like to pass it to someone else you can.

Secondly, this being the public version of the proceeding I do not intend to elicit any CSI. By all means, if you feel the need to defer a question to the CSI session tomorrow you can. Frankly, I was expecting Mr. Czarnecki to have a big red buzzer in front of him in case anybody is mentioning it. I realize he'll likely just be his usual polite self and interject, and we can proceed on that basis.

Mr. Rainkie, I do have a few policy questions on -- on your behalf as the acting president and CSO. It's my understanding the last gas hearing that we had before this Board disregarding the -- the interim hearing last November, was the General Rate Application in 2013.

Is that correct?

MR. DARREN RAINKIE: That's correct,

sir.

MR. SVEN HOMBACH: And those were the respectable days before I was allowed on the microphone. So I wasn't in that proceeding. Were you?

MR. DARREN RAINKIE: I was, sir.

MR. SVEN HOMBACH: So it is your understanding that, coming out of that proceeding, the Board approved a weather-normalized net income of $3 million annually?

MR. DARREN RAINKIE: Yes, that's I think been the target for a number of years, sir.

MR. SVEN HOMBACH: And I'll refer you to PUB Exhibit 11, which has previously been circulated, which was Board counsel's book of documents for the public session. If we can go to page 145.

(BRIEF PAUSE)

MR. SVEN HOMBACH: You'd seen an excerpt from the PUB Order that -- that set that net income allowance at 3 million?

MR. DARREN RAINKIE: Yes, Order 85/13.

MR. SVEN HOMBACH: Now, you mentioned

in response to the question by Board member Duboff that Centra's earning -- retained earnings on the distribution side -- and I'd like to draw a conceptual distinction with you between the gas and transportation portfolios in which Centra is saying the costs should be recovered on a flow-through basis compared to the costs of distribution on which the Utility intends to earn a net income.

You'd agree with that conceptual distinction?

MR. DARREN RAINKIE: Yes, sir.

MR. SVEN HOMBACH: And with Centra being regulated on a -- among other things, on a rate-based rate of return, you'd agree that the contractual positions that the Utility holds with respect to the cost of gas or transportation assets do not form part of its rate base?

MR. DARREN RAINKIE: That's correct. The rate base is -- is a -- is a function of the assets of the Company, although, sir, while we are regulated on a rate-based rate-of-return basis, a number of years ago we have commenced filing cost-of-service-like applications.

So I -- I think we have I guess two (2) tests in this jurisdiction. We -- we've set -- tend to set rates on a -- on a cost-of-service basis much like we do on the electric side of the business. And we have a rate-based rate-of-return calculation as a -- as a check, if you like, that we're in tune with the relevant legislation.

MR. SVEN HOMBACH: Correct. And there was, in fact, an early Board Order that referenced that the Utility is effectively regulated on cost-of-service now.

You also mentioned, Mr. Rainkie, that one should not look at the 2013/'14 gas costs in isolation. You'd agree with me that, on the distribution side, the Utility is also regulated on a weather-normalized basis?

MR. DARREN RAINKIE: Yes, sir.

MR. SVEN HOMBACH: And what that basically means is that weather swings are not taken into account in regulating the Utility's income, but rather the income is set based on normal weather. And the intention is that you earn money -- more money in a cold year, less money in a warm year?

MR. DARREN RAINKIE: Yeah. I think the intention, sir, is that you don't know what weather's going to be. So we -- we set rates on a forward-looking basis on normal weather.

And we expect that, over time, the pluses and minuses, the -- I hate to use the word "profit" and "net income" because it sounds like Centra's here to enrich itself. I mean, we're here, just like on the electric side, to -- so I prefer to think of these things as contribution to financial reserves and -- and those types of things.

But the -- the notion is -- is that you set rates on a forward basis based on normal weather because we just, as we talked about this morning, do not know what the weather's going to do to you, and that over time, unless there's some systematic bias in how you're calculating your -- you know, your forecasts, your load -- your -- your volume forecasts, that those things will even out over time.

MR. SVEN HOMBACH: Right. If we could go to page 16 of Board counsel's book of documents, that, sir, is an excerpt from Centra's financial statement. And you do, in fact, see that rather than earning 3 million during the very cold winter of 2013/'14, the Utility earned an actual net income of 20 million?

MR. DARREN RAINKIE: That's correct, sir, for 2013/'14.

MR. SVEN HOMBACH: But the actual

earned in 2015 is down significantly from that to 10 million?

MR. DARREN RAINKIE: Yes. The 2014/'15 was colder than normal, but not anywhere close to what happened in 2013/'14.

MR. SVEN HOMBACH: Neither of those amounts, of course, takes the weather into account so I'd like to take you to page 59 of the book of documents, which shows the weather normalized net earnings. And I'd like to take you to the two (2) right most columns for 2013/'14 and 2014/'15.

(BRIEF PAUSE)

MR. SVEN HOMBACH: What you see -- if we could scroll to the right, please? On a weather normalized basis, would you agree that Centra earned a net income of 5.3 million in 2013/'14?

MR. DARREN RAINKIE: Yes, that's my understanding of what this calculation is attempting to do.

MR. SVEN HOMBACH: And that's where we see the very significant weather impact, right? It's an almost 15 million weather impact compared to a weather normalized net income?

MR. DARREN RAINKIE: That's correct. That's my understanding, as well.

MR. SVEN HOMBACH: If we then look to the right most column, 2014/'15, we see that the difference between the actual net income and the weather normalized net income is a lot less. In that case, only about eight hundred thousand (800,000)?

MR. DARREN RAINKIE: Yes, eight hundred and twenty-eight thousand (828,000).

MR. SVEN HOMBACH: Would Centra characterize this as a very average or normal year, 2014/'15?

(BRIEF PAUSE)

MR. DARREN RAINKIE: Sir, by the calculation it would appear so. What's escaping me is we probably have degree day heating data that could tell you what percentage variation there was. Probably somewhere on the record it's there, but not at my fingertips.

MR. SVEN HOMBACH: So if for tho...

(BRIEF PAUSE)

MR. DARREN RAINKIE: Sorry, sir, I was just conferring with my colleague. Could you, please, repeat the question?

MR. SVEN HOMBACH: It's okay. I stopped in mid sentence, so I'll start at the beginning.

If we look at those two (2) years together, 2013/'14 and 2014/'15, then you'd agree with me, sir, that compared to the 3 million weather normalized net income that the Board set after the 2013/'14 GRA, Centra is in a better position by about $9 million?

MR. DARREN RAINKIE: You're taking 9.3 million plus five point three (5.3) minus six (6)? Is that your proposition, sir?

MR. SVEN HOMBACH: Yes.

MR. DARREN RAINKIE: Yes, for those two (2) years. Of course, there's other years on this chart if we go back to 2003/'04 where there was loss, but for those two (2) years, yes.

MR. SVEN HOMBACH: For me, as a lawyer, it's always heartening when somebody that actually has an accounting background confirms my math. Thank you.

MR. DARREN RAINKIE: Sir, as CFO my

role is to ask dumb questions and fuddle up the -- the calculations, and then these fine folks here, you know, they set me straight as well, so don't feel too bad about it.

MR. SVEN HOMBACH: But, Mr. Rainkie, Centra is intending in this Application to have its distribution revenues and distribution charges finalized despite this only being a cost-of-gas application?

MR. DARREN RAINKIE: Sir, I'm not sure I'm with you on that. We're asking for final approval of gas costs, and disposition of gas costs deferral accounts.

MR. SVEN HOMBACH: Well, perhaps we can go to the Application overview, sir. If we flip to page 6 of the book of documents, we see in parts E and F of Centra's Application that, among other things, it's looking to finalize distribution rates, and then that's what I just wanted to confirm with you, that you're not just looking to finalize gas costs, but also distribution rates?

MR. DARREN RAINKIE: Sir, there's a small part of gas costs that fit into distribution rates, and I -- subject to check with Mr. Barnlund on the panel, I think that's what we're -- I'm trying to remember what Order 85/'14 was, but --

MR. SVEN HOMBACH: Is that only with respect to unaccounted for gas, Mr. Rainkie, or --

MR. DARREN RAINKIE: That's the part --

MR. SVEN HOMBACH: -- what --

MR. DARREN RAINKIE: -- of gas costs that fit into distribution rates. But as I recall, the -- I guess my impression is that when we had a general rate application for 2013/'14, that any of the non-gas costs were approved as final, we -- we don't go back and confirm non-gas costs as final or otherwise. I think the original Order is a final Order after a full public hearing.

MR. SVEN HOMBACH: If we look at Part D though, that is looking to finalize distribution sales rate effective August 1, 2013.

Are -- are you drawing a distinction between just seeking finalization of a portion or are you looking to have the previously approved distribution rates finalized now?

MR. DARREN RAINKIE: Well, sir, I -- as long as I've been here, I don't think we've final -- ever finalized the distribut -- sorry, I'll back up.

When we have a full General Rate Application and determine non-gas costs, as far as I'm concerned, those -- that portion of the rate is final. It just so happens is there's a small part of gas costs that actually fit into the distribution rate. And that's what we're asking to finalize in this particular application.

MR. GREG BARNLUND: Mr. Hombach, if I may. We also recover our supplemental gas deferral account balances by way of riders that are placed in the distribution line as opposed to the supplemental gas line. So it's a combination, as Mr. Rainkie alluded to, of unaccounted for gas costs and the rate riders, the supplemental gas rate riders; it's those two (2) components.

And that's what we'd be seeking finalization of, but they are embedded within those rates.

(BRIEF PAUSE)

MR. SVEN HOMBACH: Based on the integrated financial forecast, or the financial forecast for Centra that's been filed in this proceeding, is it currently Centra's intention to only come in for a GRA for the 2017/'18 fiscal year?

MR. DARREN RAINKIE: Sir, I think we

should probably flip to the IFF for this discussion. I know you've kindly put it in here somewhere.

MR. SVEN HOMBACH: It's in Tab 2.

MR. DARREN RAINKIE: Page 42, I think, of your -- no, that's the electric one.

MR. SVEN HOMBACH: Page 33.

(BRIEF PAUSE)

MR. DARREN RAINKIE: Thank you, sir. I haven't had an opportunity to go through the book of documents as much as I normally would. Yeah, so if you look at the -- if you look at the 2016/'17 column, when the IFF was prepared last year, we're not forecasting the need for a general rate increase in 2016/'17.

And then when you go down the 2018 column you see the 2 percent in terms of percentage increase. So that's what we were forecasting at that point, was a general rate increase requirement in 2017/'18. But, of course, we'll be doing a new IFF this fall which would probably go in front of our Board on its December 2nd meeting. And we won't make a final determination on that until we have that forecast in hand.

MR. SVEN HOMBACH: But at this point in time, sir, do you have reason to believe that Centra will come in for an earlier GRA or should the Board be expecting to next have the utility file a general rate application sometime late in 2016 or early in 2017?

MR. DARREN RAINKIE: At this point, I wouldn't be expecting a general rate application. I think after -- you know, after what we just looked at the last two (2) years of -- of net income we can probably -- that will help us to defray any cost increases that are coming in the next year, so I would expect that we would be looking at 2017/'18. Of course, that assumes that gas costs are approved.

Once again, as we talked about just a few minutes ago, if we were to receive a disallowance of gas costs there may be a different outcome.

MR. SVEN HOMBACH: Given the $9 million extra dollars by way of weather normalized net income, sir, I'd like an undertaking from Centra to file an IFF that would assume that, on an interim basis, those 9 million have to refunded to ratepayers over a one (1) year period and another one that assumes that only half of that amount will be refunded.

MR. DARREN RAINKIE: Sir, I guess I'm not understanding the context of the -- of the question 'refunded'. There is no refund mechanism with respect to net income. That's -- that is what weather-normalized means, is that we look at the pluses and minuses.

We assume, unless there's something wrong with the way the calculations are devised in the first place, that the pluses and minuses will balance out over time. And if they do, then we don't go back and refund or recover. Like, there is no refund or recovery account around net income and distribution rates. So that -- that term doesn't ring a bell with me for --

MR. SVEN HOMBACH: To the -- to the extent that I'm -- I'm clear. What I'm asking Centra to assume for purposes of the undertaking is that there would be a rate rider applied over the period of one (1) year in the amount of $9 million. Or, conversely with part 2 of the undertaking, in the amount of $4 1/2 million.

MR. DARREN RAINKIE: I'm still drawing a blank, because there are no rate riders for non-gas costs. As far as -- I -- I've been involved in Centra regulation for twenty-five (25) years, and there is no such thing as a -- as a rate rider for non-gas costs. We -- we look at the financials. We look at the -- the outlook, and we make a determination whether we think we need a rate increase to -- to bolster our financial reserves. But we don't refund --

MR. SVEN HOMBACH: And I --

MR. DARREN RAINKIE: -- changes in net income through rate riders.

MR. SVEN HOMBACH: I appreciate you saying that this is not something that has been done, sir. All I'm asking is for an undertaking to assume that this has been done, and to show the financial implications thereof.

What I'd suggest to you is that conceptually that would be very similar to the undertaking -- to the Information Request that Centra has previously answered, assuming that a portion of the PGVA balance would be disallowed.

MR. DARREN RAINKIE: Well, we certainly can do any type of a calculation. But I -- I -- file any pieces of paper we want, but I certainly would be very concerned about that undertaking, in that suddenly we've changed the basis of regulation at Centra Gas. So it's not about doing the calculation, which we'll do for you by the way. But I'd like to make sure that the Board understands that, that is not the way that gas utilities have been regulated.

And, as I said, I have never received a -- a request in all the years that I've sat in this chair, when weather was warmer and we lost 6 or $7 million, to provide a calculation of, you know, what would happen if Centra were to recoup that 6 or $7 million. So I'll leave it at that.

MR. SVEN HOMBACH: But you're providing the -- the undertaking?

MR. BRENT CZARNECKI: Mr. Hombach, can you repeat the undertaking for me please? Is it -- is it a calculation to --

MR. SVEN HOMBACH: It's to --

MR. BRENT CZARNECKI: -- to assume that the Board has disallowed primary gas costs to the effect of 9 million and 4 1/2 million?

MR. SVEN HOMBACH: Not quite. Mathematically what I am looking at is an assumption, an IFF based on two (2) assumptions.

Assumption number 1, and that's the first half, that a rate rider of $9 million owing to customers would apply over a period of one (1) year. And part 2 of the undertaking that a rate rider of 4 1/2 million refundable to customers would apply over a period of one (1) year.

MR. BRENT CZARNECKI: So I'm perhaps echoing Mr. Rainkie's comments. And I'm failing to see the logic as to why we would put a rate rider in place. It would more -- it may make more sense to just have the mathematical calculation to assume that a certain amount of primary gas cost is actually recovered, less those amounts. And I'm -- I'm trying to walk the line here as well. But there's some significant legal implications as to how this undertaking is framed.

And I certainly do not want to prejudice Centra's argument that the net income and the retained earnings that are flowing directly from a final GRA Order are final. And they are, in fact, final. It's a big distinction legally, and I'm sure you're aware in -- in terms of rerunning financial scenarios adjusting final orders versus a question of whether or not the primary gas costs, including the supplemental cas -- gas costs have been reasonably incurred by Centra per the rules of the game.

So I'm -- we're walking on thin ice, but I want to make sure that that distinction is clear from Centra's perspective. Not only from Mr. Rainkie's, but from a legal perspective. And that's why I think it's extremely important that we clarify what exactly it is the Board is requesting, and perhaps we can take it under advisement.

MR. SVEN HOMBACH: Perhaps for purposes of answering the undertaking, Mr. Czarnecki, it doesn't matter so much how the question is phrased. Because the math -- I do believe Centra understands. But certainly I take your point of clarification, and it should be clear to the panel.

In the interim, can you please confirm that, mathematically, those two (2) IFFs will be filed?

(BRIEF PAUSE)

MR. BRENT CZARNECKI: We'll undertake to -- to do that, Mr. Hombach, to do the mathematical calculation as to what a reduction of 9 million and 4 1/2 million represents.

--- UNDERTAKING NO. 2: Centra to provide mathematical calculations as to what a reduction of 9 million and 4 1/2 million represents

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: If we could go to page 33 of Board counsel's book of documents, please.

MR. NEIL DUBOFF: Sorry, can you repeat that?

MR. SVEN HOMBACH: Page 33.

(BRIEF PAUSE)

MR. SVEN HOMBACH: And can we scroll down a bit, please?

Mr. Rainkie, this is a question for you not so much in your new capacity as acting CEO, but in your former and still current capacity of VP finance. The most recent financial forecast that's been filed with this Board is projecting a weather-normalized net income of $7 million for 2015.

Are you in a position to advise what that number will likely be by the end of the gas year -- sorry, by the end of the fiscal year?

MR. DARREN RAINKIE: I can tell you where we're at now, and we're running pretty close to our forecast. I think you have the June financial information in the -- in the package. And there was an $8 million loss on gas operations till June of

2015, which was pretty much bang on the forecast.

The difficult part, as we've been talking about this morning, is that, if you want to understand Centra's financial results, you better wait till the end of the winter because $3 million is a very tight number given, you know, $300 or $400 -- $300 or $400 million worth of revenue.

But weather will significantly change that amount. So I can't make a prediction, no more than Ms. Stewart can make a prediction at this point sitting here in end of September, what the net income is going to be.

If you can tell me what mother nature will do to us over the winter, then I can make a prediction. But what I can tell you right now is that, in the first, you know, three (3) months, we're -- we're very close to what our forecast was.

MR. SVEN HOMBACH: I don't think I would want to venture to make that prediction. I'm probably the least qualified person in the room to predict the weather. I may have misspoken and asked for 2014/'15.

Sir, can you just clarify that your response was with respect to 2015/'16?

MR. DARREN RAINKIE: I knew what you

meant even though you used the wrong year. That -- that's -- sorry. Yeah, we are in the 2015/'16 fiscal year.

MR. SVEN HOMBACH: I appreciate that, Mr. Rainkie. And perhaps if we could go to page 55 for a moment, we'll see the 8 million loss that you referred to for gas in 2015.

Can Centra advise just whether those numbers are generally in the ballpark or whether that has caused any concern to date?

MR. DARREN RAINKIE: You know, my -- my recollection is that the actual net income to June of '15 was within about fifty thousand dollars ($50,000) of what we forecast. So that's pretty much bang on.

We do go through -- there's a natural cycle of going through a loss position early on in the year because a lot of our costs are fixed. And of course most of our revenue is bunched up in the winter heating season.

So we come out of a -- we go into the fall with a fairly large loss of probably, you know, 18 to 20 million. And then we drag ourselves out of it, depending on what happens on the weather.

But as I said, you know, when we look

at this $3 million number, it's a pretty small number in terms of absolute dollars. And I think we have to be careful too in context about some small variations around it.

Like the difference between $3 million net income and $5 million net income in terms of the weather risks that we face is fairly minimal, as would be the case of the difference between an actual net income of $1 million -- you know, $1 million and $3 million.

So, you know, thinking there's going to be some tight range around the $3 million is -- that's -- you shouldn't be thinking that way unless it's a real, you know, normal year and every cost projection comes in exactly as -- as predicted.

There is going to be some varia -- variation around that number, and it's not a bad thing that there's variation. It's just a natural circumstance that we -- we have ourselves in.

MR. SVEN HOMBACH: So while we're on the issue of the quarterly report, Mr. Rainkie, I'd like to refer you to page 51 of that document. I do recall sitting in the hearing room with you in the Hydro GRA earlier this year, and the quarterly update again references the financial changes that Manitoba

Hydro, and by that virtue Centra, are implementing.

The Utility is now moving to International Financial Reporting Standards?

MR. DARREN RAINKIE: Yes. This is, in fact, the first quarterly report that uses IFRS, or International Financial Reporting Standards.

MR. SVEN HOMBACH: And you're, of course, aware of the Board's ruling on the Hydro side with respect to the switch to the Equal Life Group methodology of depreciation?

MR. DARREN RAINKIE: Yes. The Board's ruling for rate setting purposes, yes.

MR. SVEN HOMBACH: Can you advise what Centra Gas is doing in light of the Board's ruling on the Hydro side?

MR. DARREN RAINKIE: Well, these were -- these were financial results to June 30th, so this doesn't reflect the -- the decision of -- of the Board with respect to rate setting on the electric side that we received a month or so -- a couple months ago.

So we will have to look at that decision and decide what financial reporting implications there are of that decision for our second and third quarterly report, which we have yet to produce. I -- I think we would generally, unless we were advised otherwise, take the -- the approach that -- what has been directed on the electric side of the business would work for the gas side of the business, if -- unless the Board has a -- has an issue with that.

I don't see any difference between the two (2) fuels, so to speak, that -- or two (2) energy sources that would -- would result in a different Application.

MR. SVEN HOMBACH: Has Centra given any thought to how that decision would impact the Utility's net income results for the current year?

MR. DARREN RAINKIE: No. In fact, I think we're going to have to seek some insight from the Public Utilities Board in short order in terms of the potential financial reporting implications on both the electric and gas side of the business. I think we were -- we're going to reach out to the -- or have reached out to the advisors, and we'll have to confirm with the Board our understanding at some point.

What I'm not sure is if -- if that understanding will be crystalized in time for second quarter reporting, or not. And if not, I'll probably have to put a note in this report that we're still working through the financial reporting implications of the Order.

MR. SVEN HOMBACH: And you referred to CGMI-15 (phonetic) earlier. Do you -- can you advise the Board when that's going to become available?

MR. DARREN RAINKIE: Our plan would be to go to the December 2nd meeting of the Manitoba Hydro Electric Board seeking approval of that -- of that forecast. Now, I mean, they always have the option of not approving it but that's -- that's our plan and our goal at this point.

MR. SVEN HOMBACH: I'd like to switch topics now and actually deal with the gas cost update. If I could refer the panel to page 200 of the book of documents? That is Schedule 3.12.4 from the September 11 update that was filed with the Public Utilities Board. Mr. Rainkie, I'm not sure if that question should be addressed to you or someone else on the panel.

We see a $12.8 million difference on the transportation side between what is recoverable at existing rates and what is forecast for 2015/'16.

Can Centra comment on the public record why there is such a large discrepancy?

MR. BRENT SANDERSON: Yes, I can, Mr. Hombach. That difference between what would be recoverable with existing transportation-based rates versus our forecast cost for the '15/'16 year are comprised of the following components.

Centra has increased its firm capacity levels from western Canada as has been discussed through -- in our Application and responses to numerous IR responses, and in our rebuttal evidence. That contributes $5 million of the $12.9 million.

In addition, there's been a deterioration of the value of the Canada dollar relative to the US dollar since Centra last adjusted its non-primary gas rates resulting in a $3.6 million annual increase in the cost of its US transportation and storage assets in Canadian dollar equivalents.

In addition, the National Energy Board January 1st, 2015, ordered the implementation of abandonment surcharges on all interprovincial pipelines in Canada to pre-fund the eventual abandonment and retirement of these facilities. These abandonment surcharges contributed an additional $2.5 million in our '15/'16 forecast year to our transportation costs.

A recalculated five (5) year rolling average of capacity management revenues contributes an additional $2.5 million. In other words, capacity management revenues have been trending lower in recent years as a result of the elimination of FT ram (phonetic) on the mainline. So, the five (5) year rolling average is $2.5 million less than the last time we adjusted our non-primary gas base rates.

And then another couple of small items. There's been an increase in compressor fuel costs that contributes four hundred thousand dollars ($400,000) to the $12.9 million increase. And then there is an offsetting $1.1 million dollar amount that is the result of applying our forecast rates against the '15/'16 volume forecast, the volumes within which have increased a bit compared to the last forecast on which our non-primary gas base rates are based, and the sum of that is the $12.9 million.

MR. SVEN HOMBACH: Thank you, Mr. Sanderson. And while we are on that topic I'd like to take you to Schedule 3.11.1 from the gas update. Now, unfortunately, that's not in the book of documents. Ms. Villegas, if you could make that accessible, I would appreciate it.

While this is being loaded, in this application and again, Mr. Rainkie, that might be a question for you, Centra is looking to recover the 2014/'15 gas year balances. And the gas year, of course, does not end until October 31st and -- like the fiscal year.

Can you advise why Centra is looking for an Order to recover PGVA balances on a gas year that has not yet ended?

MR. BRENT SANDERSON: As Centra stated in an IR response associated with this proceeding, in the past, Centra typically manages gas cost deferral accounts over its annual fiscal period, which runs from April through March of each year. And I believe it was 2008 we moved the management of those accounts to be consistent with the gas year.

The fact that the annual deferral management period was out of step with the annual period over which they're recovered drove certain residual balances accumulating in those accounts, so movement to the gas year tended to minimize the magnitude of those balances.

So prior to Centra moving to managing its gas cost deferral accounts on the basis of its gas year, a typical annual process for Centra would have involved just that, a filing of an application late in the calendar year and Centra seeking final approval of its gas cost deferral balances to the end of March, and then an Order based on a forecast of those balances, the best forecast available at the time that its pre-hearing update would have been filed, so, still subject to some variation due to a few months of actual results being incorporated into those.

And so any resulting difference Centra would typically bring forward an account for and provide a detailed variance analysis in a future proceeding, again, like all purchase gas variance accounts. That difference would accumulate in those accounts to be disposed of in a future period in rates either plus or minus.

So in terms of wrapping up these three (3) years of gas counts at this one proceeding, Centra felt it wouldn't be out of the realm of what was commonplace in the past to seek final approval of its '14/'15 gas year gas costs as part of this proceeding and seek approval on a final basis.

And then, as in the past, any subsequent difference between what was embedded in rates for November 1 relating to those '14/'15 gas cost deferrals Centra will subsequently bring forward at a future proceeding and account for it at that time.

MR. SVEN HOMBACH: If we could go to the schedule, and it's Schedule 3.11.1, which is just one (1) page after the book marked 3.11.0.

The most recent update that Centra has filed, Mr. Sanderson, is based on end of July data or newer data?

MR. BRENT SANDERSON: It's based on actual data through to the end of June and then for the foreca -- forecast period based on market data, such as future's market prices as of July 31st, 2015.

MR. SVEN HOMBACH: Could the Board on those issues request a -- or can the Board expect a further update to be provided prior to the conclusion of the proceeding?

MR. BRENT SANDERSON: No, it was not Centra's intention to find -- file an additional update.

Centra's month -- as is indicated in Centra's monthly PVGA reporting to the Board, which the last round that was provided to the Board, it will show that there's minimal variation expected, even at this point in time, between what was filed in the pre-hearing update based on July 31st market pricing and what we're currently outlooking now. And we have to weigh that against the cost of doing another cost allocation study in preparation of yet another -- still a second pre-hearing update.

So we're not expecting any material difference in the year end '14/'15 balances at this point in time. Having said that, our biggest exposure in terms of variation from those amounts would be a function of late fall weather. If we get some very, very cold weather in October, for example, or much more warmer than normal weather in October. And there would be no way to incorporate that in -- into any of this proceeding in order to incorporate that into rates in either case.

MR. SVEN HOMBACH: Now that we have this schedule in front of us, I do see a similar discrepancy between the initial application and the pre-hearing update in terms of the transportation PGVA.

Is that due to the same factors that you already mentioned? Or are there other factors at play here?

MR. BRENT SANDERSON: I wouldn't characterize it as discrepancies. It's --

MR. SVEN HOMBACH: Changes?

MR. BRENT SANDERSON: -- it's normal expected variation in outlook balances for these accounts that we would expect as a matter of course as we move through the year, and the various factors that contributed to those relatively minor differences.

I'll note that in our initial application we were forecasting $35.4 million net recoverable for the three (3) years at October 31st, 2015. And the pre-hearing update shows an approximately seven hundred thousand dollar ($700,000) difference. So I'd characterize that as minor. And the various variables that contributed to that, we've provided that in the detailed variance explanation. And it's a -- it's a -- a group of different causes, as noted.

(BRIEF PAUSE)

MR. SVEN HOMBACH: If we could go back to page 59 of the book of documents please.

MR. KURT SIMONSEN: Sorry, Mr. Hombach, can we take a ten (10) minute break? The computer's frozen on us here.

MR. SVEN HOMBACH: Certainly.

MR. KURT SIMONSEN: Is that okay, Mr. Chairman?

THE CHAIRPERSON: Okay. Let's do that. Ten (10) minutes. Thank you.

--- Upon recessing at 2:17 p.m.
--- Upon resuming at 2:27 p.m.

THE CHAIRPERSON: Mr. Hombach, I believe we're ready to resume proceedings.

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: Yes. Thank you, Mr. Chairman. I notice that we're still waiting for Mr. Kostick, but if there's no concern with the Centra panel to continue and move on.

If we could go back to page 59 of Board counsel's book of documents please. We've already walked through the weather impact. And I appreciate that the degree day data for 2013/'14 and 2014/'15 is redacted.

For purposes of its weather normalized planning, Centra currently uses a rolling twenty-five (25) year average, correct?

MR. BRENT SANDERSON: I would maybe just want to put that subject to check, but I believe you're correct.

MR. SVEN HOMBACH: And the current degree day heating data is redacted, but I take it there's no concern if we go back to 2012/'13, and we just look at the impact on this public record?

MR. BRENT SANDERSON: Could you clarify for me in what manner you mean that? I'm -- I'm unsure of the question.

MR. SVEN HOMBACH: All right. I'd like to get into the financial impact of a degree day which we can easily calculate if we just look at the 2012/'13 data in front of us.

MR. BRENT SANDERSON: I guess if you want to divide a financial figure by a degree day variance, you could come up with a dollar-per-degree-day figure, if that's what you're getting at.

MR. SVEN HOMBACH: It's based on the math for 2012/'13. It amounts to about sixty thousand (60,000) -- sixteen thousand dollars ($16,000) per DDH.

MR. BRENT SANDERSON: Again, subject to me performing the calculation myself, that sounds in the ballpark, to my recollection.

MR. SVEN HOMBACH: Mr. Sanderson, on the public record, can you indicate the directionality of that amount, or is that something to be left for tomorrow?

MR. BRENT SANDERSON: Again, I'm unsure of the nature of the question, the directionality of that amount?

MR. SVEN HOMBACH: The financial impact per degree-day heating, is it going up or is it going down? Is it now more than sixteen thousand (16,000) or less?

MR. BRENT SANDERSON: It's fairly static. I really don't have the figures to -- to depict it year over year. But that type of degree-day impact sounds like it's been in the ballpark for a number of years, so I don't think there's any large directional change one way or the other. But again, I would have to go look to -- to answer it definitively.

MR. SVEN HOMBACH: Mr. Rainkie, perhaps back over to you. If we could flip to page 61 of the book of documents, that shows the results with respect to Centra's other non-gas costs for 2013/'14, actual versus approved.

We see that there's actually been a relatively significant reduction in operating and administration and -- sorry, OM&A income -- operation, maintenance, and administration.

Is that due to the cost-reduction programs that have been implemented on the Hydro and Centra side?

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

that -- that's part of it. I mean, the -- our operations are very complex. We have a number of programs that roll up into operating costs, so there's usually many smaller variances. But -- but that's -- that's a large part of it, sir.

MR. SVEN HOMBACH: On the depreciation side, we see that there's an income -- there's a difference of about 2 million between actual and approved?

MR. DARREN RAINKIE: Yes, sir.

MR. SVEN HOMBACH: Now, reviewing all of those together and subtracting the -- the cost of gas, it looks like the impact for the various non-gas factors or the changes amount to about $10 million.

Am I doing this correctly? I'm taking the 78.5 million at the bottom and subtracting the sixty-eight point five (68.5).

MR. DARREN RAINKIE: I want to be careful because the -- this -- this presentation is rather -- I don't know, it's --

MR. SVEN HOMBACH: High level?

MR. DARREN RAINKIE: Well, it makes it difficult to really understand what went on because this is kind of in a cost-of-service approach.

For instance, the furnace replace

program, $3.8 million, that -- there's no difference there. Centra didn't make or lose $3.8 million based on that. That's just I think a way these charts have been put to -- put together in the past.

We -- as has been directed by the Board in the past, we take $3.8 million and we put it in a furnace replacement program. There's no earnings one way or another on that.

So I think, in the math that you're doing -- and I'm trying to keep up with you on the fly here -- you're taking that into consideration. If that's part of it, I don't agree.

MR. SVEN HOMBACH: While on the subject of the furnace replacement program, can Centra advise what the current balance in the FRP reserve is?

MR. DARREN RAINKIE: I think it's in the annual -- at least the March 31st, 2015, balance is disclosed in the MD&A in the annual report. If -- I could have the report here with me under the desk, I can grab it if you'd like that --

MR. SVEN HOMBACH: About 19 million, isn't it?

MR. DARREN RAINKIE: That sounds -- sounds reasonable, subject --

MR. SVEN HOMBACH: You'll take that

subject to check?

MR. DARREN RAINKIE: Yes.

MR. SVEN HOMBACH: Thanks. On the subject of the corporate allocation, Mr. Rainkie, I note that in each of the years there's still the $12 million corporate allocation to Centra?

MR. DARREN RAINKIE: Yes, there is.

MR. SVEN HOMBACH: Now, Manitoba Hydro's allocation actually seems to be going down by a million.

Can you advise why Centra's is remaining constant through the -- through both these documents and the financial statements, or the forecasts that we looked at?

MR. DARREN RAINKIE: Sorry, sir, I wasn't prepared for a mini-GRA this morning, or this afternoon. Where are you -- where are you finding that from? Can you give me a reference on that?

MR. SVEN HOMBACH: If you -- if you look at page 61 of the book of documents you see the $12 million Corporate allocation. If we go back to the CGMI-14 forecast, you'd also see that that will be remaining constant for the foreseeable future.

On page 33 of the book of documents, you see the $12 million Corporate allocation?

MR. DARREN RAINKIE: Yes, I see that, sir.

MR. SVEN HOMBACH: And you mentioned the mini-GRA. I can advise it's not the intention to conduct a mini-GRA, but you'd agree that all of those issues are the ones that are usually reviewed at a General Rate Application rather than a Cost of Gas hearing?

MR. DARREN RAINKIE: Yes, in my experience.

(BRIEF PAUSE)

MR. SVEN HOMBACH: Immediately before I started the cross-examination, Mr. Rainkie, you mentioned Mr. Drazen's evidence. And you were discussing the regulatory regime by which cost of gas are ultimately flowing through to ratepayers with ratepayers taking a risk.

Does Centra adopt Mr. Drazen's evidence as it stands in the Application, appreciating that Mr. Drazen isn't here testifying today?

MR. DARREN RAINKIE: Yes, we do.

MR. SVEN HOMBACH: And as indicated by Mr. Drazen, you'd agree that any flowthroughs are still subject to a prudence review?

MR. DARREN RAINKIE: Yes, sir.

MR. SVEN HOMBACH: We'll get into the prudence review in more detail tomorrow, sir, in the CSI session.

Before I started my questioning, there -- there was a question by Board member Duboff with respect to the equity ratio. And you, sir, commented on the sufficiency of it and you indicated that you weren't -- or Centra wasn't happy with the 30 percent.

Can you advise, sir, whether the recent KPMG study that has not been released to the Board yet is looking at Centra's equity ratio in addition to that of Manitoba Hydro?

MR. DARREN RAINKIE: No, that report doesn't -- doesn't address that issue. But as I said, I think there's lots of evidence around other local gas distribution companies that are regulated that -- that the --

MR. SVEN HOMBACH: And when you referenced that --

MR. DARREN RAINKIE: -- that equity is 35 to 40 percent.

MR. SVEN HOMBACH: And when you indicated earlier that the equity for Centra used to be higher, that was in the pre-Crown corporation days?

MR. DARREN RAINKIE: Yes, sir, it was but the principle since that time is that Centra is to be regulated on a stand-alone basis, so I guess that's one of my difficulties. How we can regulate Centra on a stand-alone basis and at the same time consider Manitoba Hydro's ownership. I'm not sure how those two (2) co-exist in the same principle.

MR. SVEN HOMBACH: Again appreciating that this is not a GRA, before we go into the -- the history of Centra's decision making, I would like to take you to the financial impacts of a possible full or partial disallowance of the remaining balance.

If we could go to page 86 of Board counsel's book of documents?

(BRIEF PAUSE)

MR. SVEN HOMBACH: That is a version of the forecast that Centra -- Centra filed that assumed that 50 percent of the outstanding balance would be disallowed? And I take it, Mr. Rainkie, your department had something to do in putting this together?

MR. DARREN RAINKIE: Yes. I think the

assumption is that there would be a 12 or $13 million writeoff such that Centra's net income --

MR. SVEN HOMBACH: Right.

MR. DARREN RAINKIE: -- would be a loss of $8 million for 2015/'16 under that scenario.

MR. SVEN HOMBACH: And that would put Centra into a $8 million loss position, according to the statement for the 2015/'16 year, meaning the current fiscal year?

MR. DARREN RAINKIE: Yes, that would be the $4 million we were talking about, less a writeoff of about $12 million.

MR. SVEN HOMBACH: Without dealing with the prudence review, or the -- the merits of such a decision, Mr. Rainkie, if that were to happen would it still be Centra's intention to only come in for a General Rate Application for the 2017/'18 fiscal year?

MR. DARREN RAINKIE: The difficult part is I can't answer that question because if we were going to start disallowing prudent gas costs, once again, assuming that the prudence review is done, because that's our assum -- that's the assumption in your question, I think, and if we're going to start adjusting rate riders for distribution revenues and net income, then to me the regulatory system is a different one. I'm not sure what the regulatory system is.

So if that is the -- if that was the ruling of the Board, I guess I would have to look at if we're starting to take the -- the risk of gas supply costs at price risk. And looking at 2014/'15, one (1) of the reasons of the number that you noted for a higher net income after you adjust for weather normalization is that we had higher usage. It's a factor that Mr. Sanderson tells me there was higher usage in North America this last year while Centra takes the risk of usage in terms of its rate of return, plus or minus.

So there's been a number of years where the usage has been lower than what we forecasted and never anybody has suggested that we would recoup that money. So when you start going down these lines that we've been talking about this morning or this afternoon, I'm not sure what the regulatory construct is in Manitoba anymore. I'm not sure what the -- what the forecast should look like.

Particularly, if I have to start taking the supply price risk on $300 million of gas costs that could move around fifty (50) or 60 million, don't expect me to come back with, well, $3 million net income is not $4 million because it isn't going to be that nice and tidy, sir.

So I don't know. I can't answer that question. No LDC in North America operates under that type of regime. I couldn't even hire a rate of return expert that would give me an opinion on that.

MR. SVEN HOMBACH: But you --

MR. DARREN RAINKIE: So I -- I can't tell you that because you have to tell me what the regulatory regime is first.

MR. SVEN HOMBACH: Let's break this down, Mr. Rainkie. First of all, you -- you did agree with me that this -- that the PGVA balance would be subject to a prudence review. And it is Centra's indication that that review has to take place.

You're not suggesting it -- it's not needed?

MR. DARREN RAINKIE: No, sir, I agree with you on that. I mean, that -- that's our understanding of the way Centra is regulated. There's a review of the reasonableness or prudency of gas costs before they're passed on to customers.

MR. SVEN HOMBACH: So then let's deal with your other comment about usage. I might be confused, sir, but doesn't the weather normalization calculation take account -- take into account the usage?

And if I'm wrong on this perhaps somebody could take a minute to just explain how usage still factors into the net income after weather normalization.

MR. BRENT SANDERSON: This is probably where I should jump in and help Mr. Rainkie out and employ my load forecasting background. The -- the impact or the effect on consumption of a heating degree day is not necessarily static over time. There's a certain amount of -- as much art as science that goes into determining that and these things can change over time.

The nature of your market, the perceived value of natural gas, the extent that it's used in different applications is not constant over time. So when you see a weather normalization calculation it's based on the factors that fell out of the most recent comprehensive load forecasting effort. But in very short periods of time it's not at all unheard of to experience very -- what I would call from a load forecasting perspective some dramatic changes in -- in the nature by which your market uses gas.

Now, in the '13/'14 -- '14/'15 fiscal year we saw our loads coming in -- even after adjusting for what we believed were the space heat effects, loads were coming in somewhat higher than what we would have originally forecast. Our market forecast people don't really know yet what's causing that and whether it's transient and will go away or it's something permanent.

And there's correspondence with a number of utilities elsewhere in North America looking at market research throughout North America. And that seemed to be a phenomena that happened, not only in Manitoba, but elsewhere around North America, and everybody's kind of scratching their head as to what the cause would be.

So that's a positive usage variance. That's what we would call usage. So the risk that you're forecast and all the factors that you can quantify won't capture every consumption risk that you're exposed to. And what Mr. Rainkie was referring to is, while in thir -- in the '14/'15 ga -- '13/'14, pardon -- '14/'15 -- I better back up here. It was a period more aligned with Manitoba Hydro's fiscal year -- Manitoba Hydro's '14/'15 fiscal year, the April through March 2014 to 2015 period and what we saw that.

But then looking back at history there was a period in the three (3) years following 2005, we had a very catastrophic spike in the market price of natural gas following Hurricanes Katrina and Rita. And as utilities passed those costs through to their ratepayers there was a -- a perception that gas was not as good a value as it had been in the past. And customers undertook to conserve their usage of gas. Utilities, Manitoba Hydro included, introduced demand-side management programs. And over a three (3) year period Centra's weather normalized natural gas usage, after accounting for weather, fell over 10 percent in a three (3) year period.

And so Centra was not commona -- not compensated for those lost earnings as a result of that negative usage variance. And what Mr. Rainkie's referring to is there may be in particular years where that variation or noise in your calculation results in maybe a -- a little bit of an extra recovery. But we have also experienced far worse reciprocals of that in the past. And two (2) thou -- the period following 2005 was -- was an example of that.

MR. SVEN HOMBACH: Thank you, Mr. Sanderson.

THE CHAIRPERSON: I supp -- I suppose that I probably should make a point here, which is -- I think needs to be made. You know, we talk about regulatory construct. And the reality is we have -- we do have a regulatory construct that stipulates that Centra will be allowed $3 million a year as a -- as a net income. And we're well beyond that. And excess income has been accumulating in retained earnings.

And I -- I understand your position, Mr. Rainkie, about, you know, I know you're concerned as a CFO. Wearing your CFO hat I would be in the same shoes you are. But the reality is we have a construct that says 3 million, and we're well beyond that.

And so this Board, admittedly, we're looking at -- we're looking -- we're not looking at gas rates. But we are concerned about bills more generally, because ratepayers pay bills. So -- so there you go. That's -- that's what we're dealing with. That's -- we're try -- trying to understand what our options are, if anything.

MR. DARREN RAINKIE: Thanks for the question, sir. Actually I think it'll help clarify matters here. We're regulated based on a future test year, which means that we look at a forecast of our costs. We use our volume forecast to figure out what our volumes are going to be, and what our revenues are going to be.

And, yes, the -- the PUB I would say has targeted a $3 million net income. We always calculate rates ahead of time. But that's not the same thing as saying any variation from the 3 million would automatically be recovered or refunded. We have never had a deferral account. Like, the $3 million target's been in place for probably ten (10) or more years. I -- exactly if it was 2003 or '4, or '4/'5 which GRA it went in place.

But, we don't have a deferral account around non-gas costs and net income. The principle there is the utility accepts those risks for which it gets a rate of return through net income. In some years factors like usage, weather, credit write-offs, whatever you might have. Operating costs will re -- will result in higher earnings than the normalized amount that's put into rates. And in some years they will result in smaller amounts. But unless there is a systematic bias in there, something that's wrong with the system, usually the utility keeps the increases and accepts the reductions.

So I think we just need to clarify what the $3 million is. It has never, in my experience in the ten (10) years that we've been here -- because there are a number of years on that schedule that were losses of 6 or 7 million. And it wasn't well, you know, we took those 6 or 7 million and added them on to rates the next year. It's a -- it's a target in a future test year environment, because we set rates based on forecasts, not on actual costs.

So suggesting that we have rate riders around distribution rates or non-gas costs, however you want to cut it, is a fundamental change in the regulatory structure. It -- it's not an adjunct to what's already approved. Because I can't recall the Public Utilities Board ever taking away or adding to our net income. I mean, I'll even go back past before the $3 million target to the years we were regulated like a private company on a -- on a peer rate of return that would be recalibrated each year and calculated each year.

That's not what weather-normalized regulation means. Weather-normalized regulation means that we set rates based on our expected weather. It doesn't mean that any deviation from the normal weather rolls into a deferral account.

I -- if somebody can show me that type of a system in North America -- maybe there's one (1) or two (2), but it certainly is not in my range of experience in this jurisdiction for twenty-five (25) years.

So, to me, it is a fundamental change that would cause me to go back and say, Okay, now if -- if I have $300 million worth of gas costs that are at risk and -- and there's a 20 percent variance in them that I have to eat, it's going to chew up all of my retained earnings in one (1) years, that's a fundamental change to me.

You know, that's not -- that's not saying, Well, I can live with a net income, you know, rolling between, you know a $10 million loss and a $10 million gain. And I can take that in the system and we'll just, you know, say bygones that some -- sometime you win, sometime you lose.

If we have a system where gas costs aren't passed through and we have deferral accounts around particular types of costs that are non-gas costs, that's a totally different regulatory construct.

That's something I would have -- we would have to think about in terms of our next GRA. It wouldn't be something where we'd just file the same old IFF that we've filed in the last ten (10) years.

So -- so hopefully that -- that's clear, sir.

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: And, Mr. Rainkie, if I could briefly follow up on that, is it your understanding that '14/'15, '15/'16, and -- well, '14/'15 distribution rates have not been finalized to date? '13/'14 have by way of the last GRA. '14/'15 have not?

MR. DARREN RAINKIE: Sir, we don't finalize distribution rates. We apply for periodic General Rate Applications.

MR. SVEN HOMBACH: Right.

MR. DARREN RAINKIE: We go through a full public hearing process, and those rates are approved as final as far as I'm -- I'm concerned. This is -- there's a difference between that and gas costs, a fundamental difference.

MR. SVEN HOMBACH: There was a discussion earlier about the concept of using retained earnings to cushion the blow rather than just passing costs through. And I'd like to take you through that just conceptually, Mr. Rainkie.

Are you familiar, either from your past

life or from having reviewed Board counsel's book of documents, with the concept of the rate stabilization reserve that MPI uses?

MR. DARREN RAINKIE: I'm not overly familiar, sir, but a rate stabilization reserve or retained earnings or financial reserves, you can put different titles on it. I think the principle to me, unless I'm missing something, is the same.

You have a reasonable capital structure so that you can withstand bad things that happen to you --

MR. SVEN HOMBACH: Right.

MR. DARREN RAINKIE: -- and so that you don't have to automatically go to the customer if those bad things occur.

MR. SVEN HOMBACH: And you -- you touched on it earlier today, but has Centra given any thought to setting up a system like that to cushion the blow of weather which for Centra tends to be quite extreme, as indicated by Ms. Stewart today?

MR. DARREN RAINKIE: Sir, I -- I think of our retained earnings as that buffer. We don't call it a rate stabilization reserve, but those retained earnings, as I mentioned in my opening comments, are not there to pay a return to Manitoba

Hydro or to pay dividends to the province or -- or make sure share prices are higher.

Those retained earnings are there, they stay on the Centra balance sheet so that if things like aging infrastructure challenges us in the future, we don't have to go for general rate increases automatically. We can smooth, you know, rate increases out for customers.

So to me, it's a -- it's a similar topic, unless I'm missing something in your question. It's just we call it a different -- a different thing.

MR. NEIL DUBOFF: Well, what's the right number for the retained earnings? Because at some point, there'll be an asset review of your capital assets to know the amount that should be held in reserve for replacement or maintenance or whatever you're going to do with your capital assets.

And -- and you're going to have a -- a range of what the risk is to your -- to your retained earnings in a really bad year. You're going to have that. But where does the number stop? Because as I understood it, as I said before, the range that we -- that I understood was determined by this Board was the 30 percent.

And -- and I hear you that it's -- that

-- that other utilities are using thirty-five (35) to forty (40), and I hear you that you're saying that the process wasn't well done to get it to thirty (30).

But we are where we are because I understood that that 30 percent was to reflect the risk of -- of an unusual year, and it was set up to deal with capital replacement. That's where that number came from.

MR. DARREN RAINKIE: Sir, my recollection -- and just subject to check because it's a number of years ago -- is that figure came from a -- one (1) question to a witness for the Consumers Association, Mr. Matwichuk, who I will call -- he's a general revenue requirement expert. He reviews things like operating costs, and those types of things. He's not a capital structure or a rate of return expert.

That was one (1) question that lasted two (2) or three (3) minutes. He probably shouldn't have given his opinion on it because, in my humble opinion and no disrespect to him, he's not qualified to do that. And then suddenly that appeared in an order.

Now, if you want to go cross this fine country of ours, you can find numerous expert reports on rate of return and capital structure. We used to do them in this jurisdiction before about 1992. They -- you'd get a five hundred (500) page report from Centra's witness. You'd get a five hundred (500) page report from CAC's witness. And we would spend three (3) or four (4) days of the hearing and probably half a million dollars, determining rates of return and capital structure because that was the profit that the Utility earned back then.

But in all those documents, the -- even the -- the huge disagreements between Intervenor experts and Company experts have a range of 35 to 40 percent. So I don't know. I -- I -- and people have asked me, Well, why didn't we review and vary this Application? But, you know what, there's tonnes of findings in an order that's a hundred pages long.

And we tend to review and vary a decision. The -- the rate impacts the decision. In my mind, the 30 percent really never came into play. It was calculated at all these hearings all along the way but it really never ever came into play, so there was no reason to go back and do a review and variance.

But if you're asking me as CFO or president or whatever title I want to put on myself, if that's adequate, I don't think so. I think 35 to 40 percent is -- is adequate. So it's well established. It's well documented. We haven't spent the time and energy in this jurisdiction for a long time to review it, but I can tell you two (2) clicks of a mouse and you'll find lots of expert testimony, even amongst experts that can't agree that it's in the range of 35 to 40 percent.

MR. NEIL DUBOFF: The challenge I'm facing, as everybody here knows, I'm a newbie here. This is my first set of hearings. I'm very new here, and all I'm doing is going by the -- the -- not just evidence that's before us but an order that's before us.

Now -- now, I hear you're not giving evidence that -- and you're not arguing in favour of changing the rate at the moment from thirty (30) to thirty-five (35), but all I know is I've got an Order saying something. You're telling me that the process to get to thirty (30) was not as thorough as it should have been, and I accept what you're saying. I have no reason not to.

But what else can I go on other than the Order that's there unless an Application is made to change the Order? Because the Order that sits there, accepting that -- that -- however it got there, is something that wasn't challenged by anybody. It --

it's there.

So how do we today sit here and say that that extra 5 percent, which I understand represents some $24 million, how do I sit here today and -- and not wonder about an excess retained earnings because retained earnings, as you say, correctly reflects risk, it reflects rate of return, capital replacement, all those things that I accept. And maybe the number should have been thirty-five (35) but it is thirty (30).

MR. DARREN RAINKIE: Well, sir, I guess in the same vein that the 30 percent came out from a witness that wasn't qualified to make the recommendation, you're sitting here with the CFO of the Company that has had twenty-five (25) years of experience in doing this.

In fact, I drafted the last rate of return decision of the Public Utilities Board because I was an advisor to the Public Utilities Board between 1990 and '94. So I have worked on rate of return and capital structure for a long time.

So I'm not sure how to -- to make up for a process that perhaps wasn't as pristine as it should have been, sir. What I can only do is give you my honest answer as I sit here. When I look at the --

the risk that face the Utility, I -- I think that we have a decent capital structure. We've -- we've had lots of fits and starts and discussions about the $3 million. We had more -- more options discussed ten (10) years ago than you can shake a stick at in terms of how to deal with the change in ownership between West Coast and Manitoba Hydro to Centra.

We came into the $3 million targeted net income. Over the time frame, our retained earnings have grown by a little over $3 million a year, so in my mind the system as contemplated has worked well. The 30 percent equity ratio though that was in a finding in a Board order, I -- I grant you that, has never really been operationalized in any way. It's never been a factor in deciding rates.

We've had many cases since then where we -- we argued and we got back to the $3 million net income. So the system perhaps isn't perfect, but in my mind it's working. And when we look at the impacts that come out of the supplemental gas issue, because it's -- let's face it, it's the big issue at this hearing, the rate impacts to customers are reasonably modest.

In a year -- an extreme year -- an extreme year, I think, when you use more gas you're going to expect to pay more. It's just the way it goes in a market-driven commodity like natural gas.

I don't think it's time to throw the baby out with the bathwater, so to speak. I don't think it's time to fundamentally change the regulation of Centra gas because of this gas cost deferral. And if we were going to do that, it would be more appropriately done after a notice at a general rate application where we could be prepared to -- to, you know, address the issues appropriately.

MR. NEIL DUBOFF: And -- and I want to be clear. My comments are in no way, as I said before, suggesting that -- that I do think we should touch the retained earnings or not touch them. I -- I really just need to understand where -- where you're coming from.

MR. DARREN RAINKIE: Sir, I -- I understand that, sir. And I don't mean my comments to be derogatory in any way.

MR. NEIL DUBOFF: I -- I don't hear it that way.

THE CHAIRPERSON: You will concede, however, that Manitoba Hydro is a Crown Corporation where Centra Gas is a sub of that Crown Corporation and mostly the other gas companies in this country are private companies with, you know, expectations from shareholders and willingness on the part of regulators to give them a higher rate of return that -- than probably the PUB has traditionally granted.

So we're talking apples and orange, in some -- to some extent, by using an example of 30 to 40 percent for gas company returns?

MR. DARREN RAINKIE: We are, sir. But I guess that's the materials that we have today to deal with, the reality that we have to deal with. And, you know, as well, I -- I mean, after a number of hearings going through this ten (10) years or more ago, or maybe fifteen (15) years ago, the stated desire was to regulate Centra like on a standalone basis. So I think that squarely puts us in the -- if that's the principle of the Board, that puts us in that debate.

I don't think you can, you know, juggle both principles. You can't say, well, I want to regulate Centra on a standalone basis but I want to take all the good things about Manitoba Hydro ownership and -- you know, I think you have to pick one (1) -- one (1) perspective and deal with it; otherwise, you get a mixing and matching of -- of parameters. I mean, that -- that's the trouble I've had over the years with the 30 percent.

And the -- the stated goal of the standalone is, it seems to me, it's standalone, but we consider Manitoba Hydro ownership, which I'm confused about.

THE CHAIRPERSON: I think we've belaboured this point long enough. Mr. Hombach, are you prepared to continue?

MR. SVEN HOMBACH: I will try to belabour some other points, Mr. Chairman.

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: Just a point of clarification, Mr. Rainkie, and I hope that's going to be just a 'yes' or 'no' question.

Does Centra get the benefit of the flowthrough credit rating through the Province just as Manitoba Hydro does?

MR. DARREN RAINKIE: Yes, it does. But at Centra's capital structure it would not be able to borrow at that rate, so it's paying that guarantee fee to be able to borrow at a -- at a reasonable rate. You can't use money twice, sir. You can't say, well, that's a reason now to change the capital structure.

MR. SVEN HOMBACH: Let's actually

delve into the history of the PGVA right now, Mr. Rainkie.

Were you part of the storage before re-application back in 2012, or was that done with -- with other people?

MR. DARREN RAINKIE: No, I was corporate controllering at that point, sir, so, no, I -- I wasn't part of the -- the 2012 hearing.

MR. SVEN HOMBACH: I hope you're not -- you're not ruing those days too much then. It's my understanding that, that application was brought in the context of the TC mainline tolls increasing quite significantly as throughput on the mainline was decreasing and Centra was looking to reduce its reliance on firm transportation.

Is that your understanding, too?

MS. LORI STEWART: Can you confirm, Mr. Hombach, which proceeding you're referencing?

MR. SVEN HOMBACH: The transportation and storage portfolio application back in 2012.

MS. LORI STEWART: That proceeding was a proceeding to replace expiring US transportation and storage portfolio assets.

MR. SVEN HOMBACH: Yes, but in -- in the context of that application Centra was aware that, at that point in time, the firm transportation totals were going up significantly on the mainline?

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

MR. SVEN HOMBACH: When -- when that portfolio was put into place though, it's fair that the issue of pricing discretion for interruptible transportation and -- and setting bid floors without regulatory oversight, that wasn't on Centra's radar?

MS. LORI STEWART: That's correct. In fact, it wasn't even on TransCanada's radar.

MR. SVEN HOMBACH: And it didn't really get on to anyone's radar until the application and NEB proceeding 1-2013, when TransCanada was applying for a bid floor of 160 percent of firm transportation tolls?

MS. LORI STEWART: Just to correct the proceeding reference. It was not 1-2013. It was 3-2011, in which TransCanada applied for a range of -- of flexibility, a much more constrained range of flexibility as it relates to short-term transportation services.

MR. SVEN HOMBACH: And ultimately the -- the order that came out in March 2013 is the one (1) that then gave them unlimited pricing discretion?

And perhaps we could go to that portion of the order. It's page 140 of the book of documents.

(BRIEF PAUSE)

MR. SVEN HOMBACH: If we could scroll down to the bottom. Are you at the bottom of page 140?

MS. LORI STEWART: I have the reference. And to confirm, yes, it was the decision coming out of the RH-3 2011 proceeding that granted TransCanada virtually unlimited pricing discretion.

MR. SVEN HOMBACH: Okay. And it's fair to state that the National Energy Board certainly was aware that this could lead to very high prices during adverse weather conditions? If we actually scroll down to the bottom paragraph, that order of the NEB actually states it. And looking at the sentence that states:

"We recognize that giving TransCanada the flexibility to increase and decrease bid floors may give it the opportunity to charge very high tolls in certain markets and at certain times. For example, during significant weather events."

MS. LORI STEWART: I don't have the reference at my fingertips, but --

MR. SVEN HOMBACH: It's actually on the screen in front of you.

MS. LORI STEWART: Oh, no, I'm talking about a different reference. So, yes, I -- I can -- I've reviewed the reference that you provided to me.

But elsewhere in the RH-3 2011 decision it's outlined that the Board's view was that it would be very rare for TransCanada to be in a position to set bid floors any greater than 300 percent of the daily equivalent toll, or three (3) times the daily equivalent FT toll, such that the Board's impression of the potential for TransCanada to set bid floors at several multiples, in fact, eighteen (18) multiples of three (3) times.

We saw bid floors being set during the 2013 and '14 winter at fifty-five (55) times the daily equivalent FT toll. So I -- I think it's very safe to say that even the National Energy Board was taken aback at -- at what TransCanada was able to do given the perfect storm that Mr. Sanderson spoke about this morning.

MR. SVEN HOMBACH: And I'd like to

take you to page 137 for a moment.

Ms. Stewart, did I understand it correctly that you were part of that proceeding, and you provided evidence at that proceeding?

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

MR. SVEN HOMBACH: And if I'm looking at the paragraph that's highlighted in yellow on page 137, it certainly suggests that Centra was concerned even about pricing discretion at 160 percent?

MS. LORI STEWART: Yes, our position was that it would be preferable for there to -- for the Board, the National Energy Board, to have an understanding of how TransCanada was going to go about establishing bid floors.

MR. SVEN HOMBACH: Is it fair to say that you were taken aback yourself when the actual NEB decision came out?

MS. LORI STEWART: The entire shipper community on the mainline was taken aback.

MR. SVEN HOMBACH: Can you explain to the panel what type of risk assessment process Centra initiated in 2013 when the NEB came out with that decision that granted unlimited pricing discretion, as opposed to even the 160 percent you were concerned about?

(BRIEF PAUSE)

MS. LORI STEWART: The risk assessment that I would discuss leads naturally into the arrangements that we executed. And I'd prefer to leave that discussion to tomorrow.

MR. SVEN HOMBACH: Fair enough, Ms. Stewart. Can you advise the panel as to whether there was a formal risk analysis or report that was prepared on the impacts of the NEB's decision?

(BRIEF PAUSE)

MS. LORI STEWART: My recollection is that we summarized the NEB's decision for senior management, and would have included an outlook in terms of the potential cost implications, recognizing that, without having any experience with how TransCanada might exercise its pricing discretion, it was difficult to quantify that.

MR. SVEN HOMBACH: Right. Can I please obtain an undertaking from Centra to file a copy of that memorandum in confidence with the Board, as well as copies of any minutes of the executive committee that relate to that decision, appreciating that all of those would have to be filed as CSI?

MS. LORI STEWART: Certainly. I will undertake to provide that.

MR. BRIAN MERONEK: Just for clarification, when you say, "in confidence with the Board", is that exclusive of this Intervenor?

MR. SVEN HOMBACH: My understanding is that, as part of the access rights that you have obtained, Mr. Meronek, that would go to you as well. But perhaps Mr. Czarnecki could confirm that.

MR. BRENT CZARNECKI: We would provide it CAC, too, Mr. Meronek.

MR. BRIAN MERONEK: Thank you, sir.

--- UNDERTAKING NO. 3: Centra to file a copy of as well as copies of any minutes of the executive committee relating to NEB decision

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: Ms. Stewart, did Centra go external at all to seek some advice on the implications and on potential changes to strategy it should implement?

MS. LORI STEWART: Centra was involved post-RH-3-2011 decision and, as it is in the normal course, in ongoing gatherings of industry such as the Mainline Tolls Task Force.

So that's a forum where all of the Canadian and even American shippers who utilize the mainline come together on, at minimum, a monthly basis in order to share information and to discuss exactly things like this: What could we expect TransCanada to do?

And I mentioned that one (1) of the outcomes of that process was where TransCanada informed the market that it would no longer be providing access to short-term firm transportation. It was in essence saying, Your options are interruptible transport or firm annual transportation.

So that's one (1) forum where there was certainly discussion by impacted parties from the decision. But, no, we did not formally seek expert advice.

Given the uniqueness of the market that we serve, I think that the people in this room are best positioned to understand how -- what the potential implications are on our specific and unique market.

MR. SVEN HOMBACH: And appreciating that we'll cover this issue in a little more detail in the CSI session tomorrow, I'm trying to understand the actual chain of command as it was in 2013. You explained that in response to a question from Board Member Kapitany this morning.

If we could go to page 169 of Board counsel's book of documents, that's a copy of the org chart that was filed in the most recent Hydro GRA in this year, and it's my understanding that currently gas supply ultimately reports to the vice-president of customer care and energy conservation, in this case Mr. Kuczek.

That's the arrangement that's currently in place?

MR. DARREN RAINKIE: That's correct.

MS. LORI STEWART: Yes.

MR. SVEN HOMBACH: Okay. And can Centra advise as to how long the division manager of gas supply position has been vacant?

(BRIEF PAUSE)

MR. DARREN RAINKIE: I think it's been about four (4) years, sir. I'd have to go back because I know we had an incumbent that had a number of personal leaves over that time frame, which I certainly don't want to get into on the public record, but Ms. Stewart informs me it's around four (4) years.

MR. SVEN HOMBACH: Okay. I -- I won't ask you to get into those details, Mr. Rainkie, but can you advise whether that position was vacant in 2013, and if so how the actual decision making structure was at that point in time?

MR. DARREN RAINKIE: Sir, I think I'd -- I'd have to undertake to -- that's a very specific question about a very specific point in time. I should undertake to -- to come back to the Board with that response.

But obviously in terms of the second question, when a position is vacant the managers in this case that report to that vacant position automatically report to the vice-president directly, sir, as -- as you would expect in due course.

MR. SVEN HOMBACH: Right. I'll take that undertaking though, Mr. Rainkie. Thank you for offering that.

--- UNDERTAKING NO. 4: Centra to advise how long the division manager of gas supply position has been vacant

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: Now, in the summer of...

(BRIEF PAUSE)

MR. SVEN HOMBACH: In the summer of 2013 the other wild card, as I understand it, was whether or not out-of-path diversions would still be permitted by the National Energy Board.

Is that fair, Ms. Stewart?

MS. LORI STEWART: Yes, that's correct. TransCanada made an Application to the National Energy Board in June of 2013 requesting amendments to a number of tariff provisions, one of which was a request to restrict diversions to strictly within path.

MR. SVEN HOMBACH: Right. And Centra actually was well aware of that, and in fact intervened when the -- when TransCanada was applying to ban out of path diversions?

MS. LORI STEWART: Yes. That's correct.

MR. SVEN HOMBACH: And to assist the panel in understanding what this means, Ms. Stewart, perhaps we could go to page 192 of the book of documents.

(BRIEF PAUSE)

MR. SVEN HOMBACH: In 2013, Centra was sourcing it's primary gas at Empress, and then flowing it east on the TransCanada pipeline?

MS. LORI STEWART: That's correct.

MR. SVEN HOMBACH: And it held firm transportation capacity from Empress to the Manitoba delivery area, or MDA as it's shown here?

MS. LORI STEWART: Yes. In general, that's correct. We were also holding a swath of Emerson to MDA capacity at -- at that stage.

MR. SVEN HOMBACH: And if I can make a feeble attempt to paraphrase what out of path diversions mean, out of path diversions mean that if you can sell the gas to somebody that's further out than the area for which you hold transmission capacity, you could do so by paying the incremental firm transportation toll?

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

MR. SVEN HOMBACH: And in that proceeding, TransCanada had argued that Centra could mitigate any fallout by banning out of path diversions by simply extending its firm transportation from the MDA all the way to Emerson where there's another hub?

MS. LORI STEWART: That's correct.

MR. SVEN HOMBACH: And Centra argued against this in front of the National Energy Board?

MS. LORI STEWART: Yes. Centra, along with every LDC Intervenor, argued quite vigorously against the proposal to make this tariff amendment because it would have significantly impacted our ability to mitigate the unutilized demand charges associated with holding firm annual transportation.

MR. SVEN HOMBACH: And Centra's concern, as I understand it, was that there simply weren't any customers between Empress and the MDA that would be purchasing transportation capacity from Centra?

MS. LORI STEWART: That's correct, given that the primary market between Empress and the

Manitoba load centre is the Saskatchewan market which has access to significant local production as well as it is -- is interconnected with the Nova Gas Transmission Limited system, or NGTL system, at the Alberta/Saskatchewan porter -- border at many different points.

MR. SVEN HOMBACH: Knowing what you knew in the summer of 2013, Ms. Stewart, and by 'you' I mean Centra, was there a separate risk review process of what it would mean if out-of-path diversions were banned and how Centra should mitigate?

We've already discussed the risk review process dealing with the March 2013 decision. Was there a separate risk review process that dealt with the fallout of TransCanada's application to limit out-of-path diversions?

(BRIEF PAUSE)

MS. LORI STEWART: I'm concerned about the words 'risk review process' being embedded in the panel's mind, and then, them getting something different from Centra and...

MR. SVEN HOMBACH: I wasn't trying to put words into your mouth, but I assume there was some type of review process. I'm trying to flush out what that process was and what the decisions were coming out of it.

MS. LORI STEWART: So certainly senior management was briefed in terms of the implications of TransCanada's application. And in this case, the potential implications were -- were clear and obvious in the absence of out-of-path diversions.

Centra had two (2) choices, either to incur additional firm annual transportation costs in order to contract to Emerson, a supply hub, or to maintain its Emerson to MDA transportation and forego the revenues earned in its optimization activities given that it would essentially have no market to which to divert gas.

MR. SVEN HOMBACH: And it's my understanding, Ms. Stewart, that the incremental tolls from the MDA to Emerson would add about 15 percent over the Empress to MDA tolls?

If you disagree with that number, perhaps you can advise by undertaking if --

MS. LORI STEWART: I'll accept it, subject to check.

MR. SVEN HOMBACH: Certainly. So to the extent that there were separate memos to senior management or separate executive committee minutes dealing with the second issue, the out-of-path diversions, I'd also like an undertaking to have those filed in confidence.

MS. LORI STEWART: In that instance, given how clear the impacts were, I would suggest that the -- the records, so to speak, of Centra's position is clear in -- in the evidence that Centra filed in the RH-1 2013 proceeding. Our evidence is always reviewed by the vice-president in charge of gas supply and, thus, had executive endorsement.

MR. SVEN HOMBACH: I appreciate the position Ms. Stewart, but I'd still like the undertaking to allow the panel to have access to those documents.

MR. BRENT CZARNECKI: Mr. Hombach, we'll do that. And I'm just going to put a caveat on there that -- of course, that if it's subject to the ultimate decision to pursue litigation, which, in this case from my head, I think it was, we -- we'll have to assess that privilege in disclosing those documents.

MR. SVEN HOMBACH: So you're taking it under advisement. Is -- is that what I'm hearing?

MR. BRENT CZARNECKI: Yes. And we'll do our best to give the information to the Board if we can.

MR. SVEN HOMBACH: Certainly. Thank you.

--- UNDERTAKING NO. 5: Centra to file in confidence any memoranda to senior management dealing with the impact of out-of-path diversions being abolished, and any executive committee minute regarding same.
(TAKEN UNDER ADVISEMENT)

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: Mr. Rainkie, you were earlier asked by the panel members about Centra's decision-making process in coming to the Board when it became apparent that the PGVA balance was increasing. And I appreciate that you made your position clear already.

You're aware of the directive in Order 128/09 that if Centra becomes aware of any material change in its financial circumstances it has to come to the Board?

MR. DARREN RAINKIE: Yes, I recall that, sir.

MR. SVEN HOMBACH: And getting back to your concept of the regulatory construct, there's a difference between advising the Board or coming before the Board to seek an actual remedy in terms of changed rates?

MR. DARREN RAINKIE: I'm not sure I understand the question, sir.

Could you repeat it?

MR. SVEN HOMBACH: Centra advising the Board of a change in its financial position is not necessarily contingent on Centra coming before the Board to seek a change in rates?

MR. DARREN RAINKIE: I would agree with that, yeah.

MR. SVEN HOMBACH: Given the -- the very significant amount that accrued in February and March of 2014, can you give some indication to the panel as to where Centra sees the threshold of materiality?

MR. DARREN RAINKIE: Well, getting back to the directive, I guess I always took that directive of being is there a significant change in our financial position being one (1) of, I don't know, a large infrastructure issue or something of -- of that nature. We deal with PGVA accounts all the time, if you look at the evidence that Mr. Sanderson provided this morning.

And so I -- I guess I never necessarily connected a PGVA balance with a significant change in -- in financial position. I think we were monitoring the situation as we talked about earlier this morning. We were looking at what would happen in the months after Fe -- in -- in February, March, April, May, and then looking on proposals to deal with the situation.

So I -- I didn't -- I guess I didn't think of it in that regard as being a change in financial position. We deal with PGVAs all the time. We're able to flow them through. I realize this is a larger one (1) than we've dealt with probably in a couple of years now. In fact, there's probably been some refunds in going back in some of the warmer years like '11/'12, but...

MR. SVEN HOMBACH: So in -- in your mind there's no firm number where Centra would say, Once we exceeds 25 million and once we exceed 50 million in a PGVA we should advise the Board?

MR. DARREN RAINKIE: No, I -- we haven't had type of a target. I suppose now we are providing monthly PGVA reporting to the Board, although even in that case it's after the fact.

Just like financial statements, you don't have information in your GL the day that the -- you know, it clicks over from the 31st to the 1st. I don't get financial information usually till about the 20th of the month. So perhaps even it, by the time we collect it and file it, is a month or so out of date.

But, you know, I -- through that and other mechanisms I'm sure we can remedy the situation. I -- I don't think we -- I don't think we intentionally withheld information, you know, to the detriment of the Public Utilities Board. That wasn't certainly our intent. We were monitoring the situation, and we came forward when we felt it was appropriate to -- to advise the Board.

So I -- I can assure the Board there was no malice of intent in terms of we were trying to keep something a secret. And I think we were monitoring it and seeing if any of it would rev -- reverse before we got to the point of -- of looking at the disposition of the -- of the balance.

MR. SVEN HOMBACH: Somebody on the panel mentioned earlier that the supplemental gas accounts were about 8 percent of consumption.

Do I have that right?

MR. BRENT SANDERSON: That would be in a typical year, based on Centra's current portfolio and expectations under normal weather conditions. It can vary from year to year.

MR. SVEN HOMBACH: Has Centra given any thought to possibly adjusting supplemental gas rates on a quarterly basis, similar to primary gas rates?

MR. BRENT SANDERSON: Well, it's been considered, but for the reasons that we enumerated earlier today, it wouldn't be practical or achieve the desired effect given the uncertainty regarding whether we're going to need to purchase meaningful quantities of supplemental gas in any event. You can look at changes in various market indicators or futures prices at various hubs. At any point in time we have no idea whe -- whether we will be purchasing any supplemental supplies or where we might purchase those.

So we wouldn't have a basis upon which to adjust the supplemental rates in the first place. And in as many cases as not, it would probably be counterproductive.

MR. SVEN HOMBACH: Let me ask you another question then. While the rates are currently not adjusted quarterly, it's my understanding that the billing percentages are.

Is that correct?

MR. BRENT SANDERSON: Yes, but that's a completely different phenomena. That has to do with balancing our underlying purchases, the splits between primary and supplemental gas versus what we bill from customers over the course of a gas year.

So it's not a rate issue. It's in order to ensure that the ratios of primary versus supplemental gas over the course of a year and in any given quarter, they're very likely not to reflect what's going on in that quarter, but to make sure that they balance as closely as possible over the course of a year because there's considerations other than just Centra.

It affects third-party marketers who are active under the Western Transportation Service who are unable to serve their customers' primary gas requirements. And that's on the basis of what Centra bills their customers as opposed to what's going on on a purchase basis underlying that.

So we have to make sure that to the best -- to the greatest extent possible over the course of a gas year, those two (2) quantities match.

So it's more of an operational phenomenon than a rate phenomenon.

MR. SVEN HOMBACH: And just to be clear, currently those are adjusted on a quarterly basis, but not looking out simply to the next quarter, but rather looking out to the end of the gas year, meaning October 31st?

MR. BRENT SANDERSON: Yes, with the caveat that they may be adjusted. There's been many quarters where we would leave them unadjusted. There would be so need. So it's not necessarily the case that we would adjust them.

We would adjust them on a quarterly basis if there's an indication that that is what is required to balance those two (2) quantities over what remains in the gas year.

MR. SVEN HOMBACH: So given the variability that was alluded to this morning, and certainly given the variability that you saw in 2013/'14, has Centra given any thought to changing that billing percentage adjustment from quarterly to monthly? And if so, why has Centra rejected that idea?

MR. BRENT SANDERSON: Well, again, as Mr. Barnlund spoke about, we balance the need for adjustments to customers' rates, and in this case billing percentages, trying to balance the need for us to operationally achieve our objectives versus trying to minimize the variation that customers experience.

So to adjust those quantities on a monthly basis, we could -- as Mr. Barnlund alluded to, with monthly rate adjustments, we could end up compounding the variability of those quantities.

If you imagine we're in the middle of the winter. We start out, we have a colder than normal November. On a forecast basis, that might indicate that we need to adjust those billing percentages upward, supplemental versus primary gas, only almost immediately to be followed by a warmer than normal month which may compound and require double the adjustment in the other direction the following month.

So customers wouldn't know - and these are my words - whether they're coming or going if we were to adjust them that frequently because we don't want to be adjusting those quantities needlessly on the basis of one (1) month's worth of results when we know that things can easily turn around the other way.

So, quarterly balances the operational requirements with making sure that they're transmitted through in a -- as timely a fashion as possible without compounding counter adjustments in future periods.

MR. GREG BARNLUND: If I may add, too, there's a risk of even further confusing customers because of the existence of cyclic billing. We don't read everybody at the end of the month, and we -- we read them over twenty-one (21) billing cycles so that, when you have a rate change on the quarter, for each customer's bill you're going to have so many billing days at the old rate, so many billing days at the new rate.

When we change the primary gas percentages, the exact same calculation needs to be done. So customers would see multiple lines on their bill at a given primary supplemental gas split, even though the rate hasn't changed. So it could generate some confusion in the customer's mind in that regard.

MR. BRENT SANDERSON: If I just might close on Mr. Barnlund's comments, because we typically are always normally making a rate adjustment on the quarter already, it doesn't add any additional lines to the bill to adjust the primary and supplemental billing percentages while we're at it.

MR. SVEN HOMBACH: Okay.

THE CHAIRPERSON: Mr. Hombach, I would suggest that we take a break here at this point, unless you have --

MR. SVEN HOMBACH: I'm expecting to be no more than five (5) additional minutes, although I hate to put that on the record, Mr. Chairman. So It's up to you. I'm certainly happy to take a break or just take a few additional minutes and finish up.

THE CHAIRPERSON: Why don't you finish your --

MR. SVEN HOMBACH: Thank you.

THE CHAIRPERSON: -- your part, and then we can take a break then.

MR. SVEN HOMBACH: Thank you, Mr. Chairman.

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: If we could go to page 174, Mr. Barnlund, you alluded earlier to the -- the budget billing program that Centra offers. I'd like to spend just a minute on the fixed rate primary gas program that the Utility offers.

We see on page 174 that the number of customers forecast in the 2014 forecast is significantly lower than in 2012. The forecast suggests that there's currently only two hundred and ninety-five (295) customers.

Based on the actuals, is that in the ballpark?

MR. GREG BARNLUND: I'd say roughly speaking that would be approximate, yes.

MR. SVEN HOMBACH: So you're telling me that if I was signing up I could move the market?

MR. GREG BARNLUND: It depends on how big your house is, I suppose.

MR. SVEN HOMBACH: Can you speak to the reasons why there is such a drastic reduction in the -- in the forecasted number of users?

MR. GREG BARNLUND: Certainly. I -- I think that this was a factor that was brought out when we did customer research during -- or in the lead up to the competitive landscape hearing where we had a customer research firm investigate customer's appetite for fixed rate products.

And it seems to be a little bit counterintuitive because customers, when prices are escalating they're interested in signing up for fixed rate products but when prices are low or relatively stable they're interest wains.

So when we see what's happened in terms

of the commodity rate environment in the last -- a commodity price environment in the last number of years, and the corresponding level of our primary gas quarterly sales rates, customers are not that interested in signing up for fixed offerings that carry some premium admittedly to them over our quarterly rate, and they're not interested in signing up for that price protection.

They're -- they're obviously not flocking to the program at this point.

MR. SVEN HOMBACH: And just to be clear, unlike other marketers Centra does not offer any door to door sales?

MR. GREG BARNLUND: That's correct, we do not.

MR. SVEN HOMBACH: Right. Has the most recent customer research been updated at all?

MR. GREG BARNLUND: To my knowledge it has not, but I could check on that.

MR. SVEN HOMBACH: Okay. Does Centra see this program as remaining viable if there's less than three hundred (300) customers with the number trending downwards?

MR. GREG BARNLUND: Well, we think it provides meaningful -- I think it provides meaningful information to customers in the market who may be considering fixed rate offerings. It provides a form of a benchmark, if you would, in terms of fixed rate pricing that -- that customers may use in evaluating whether they're interested in pursuing that -- that type of offering.

So -- so we -- even though there aren't currently a large number of many customers on the offering, we still see that it has some reasonable meaning and reasonable value to -- to keep maintaining it.

MR. SVEN HOMBACH: For my last question, if we could flip to page 179. In Order 128/'09, the Board issued a directive that Centra was to file terms of references for a review of the integrated cost allocation methodology. And Centra indicated that it intends to propose a process concurrent with the implementation of IFRS.

Can you, please, advise as to what the current status is, and when the Board should be expecting terms of reference, especially now that IFRS is being implemented?

MR. DARREN RAINKIE: Well, first of all, Mr. -- Mr. Hombach, we indicated that we would look at this directive post IFRS implementation. And

I assure you that while we've produced our first quarterly report unaudited under IFRS, we are still very much in the implementation of it. So don't look at it as a done deal.

We -- we won't be going flat out until June or July of next year when we do our audit committee in terms of getting all of the adjustments that we made audited, and then doing all the note disclosure that's required around IFRS. So our finance folks will be quite busy until -- until that, for sure.

So I think our intention on this one was to do a couple of things, if I remember correctly. Look at what happened post IFRS, and see what -- what we should do. The other thing is we were looking at simplifying, and I guess it's here in the -- in the response, we were looking at simplifying the methodology as much as we can because it I think was looked at as a bit of black box. I think that -- what pushed this directive forward in the first place was that people looked at it as a black box, where it was hard to test and -- and look at.

So in conjunction with IFRS changes where we're capitalizing less costs and less overhead costs, we're trying to also simplify the -- the system so that when we bring it back to the Board for review it's easier for Intervenors and the Board to understand, so.

But, so, at this point, we haven't -- we've been simplifying it as a natural function of IFRS as we're going along, but we haven't put it pen to paper in a terms of reference or decided how we wanted to look at this.

And I think the other elements of this was that we felt that perhaps some kind of a stakeholder process on this would work be -- better than trying to do this through an adversarial hearing process.

But, we had not intended on working on that until we finish IFRS this coming up year.

MR. SVEN HOMBACH: So what I'm hearing from you then is fall of 2016?

MR. DARREN RAINKIE: Yes. Once we were clear of getting our first audited IFRS financial statement signed off and everything in place, we -- we would look at that and -- but it was with a view to simplifying the -- and -- and probably engaging stakeholders in a different way rather than asking hundreds of IRs back and forth trying to find somebody.

I think if we can get the accountants and the advisors in the -- in the room with a white board, we can demystify this cost allocation process.

MR. SVEN HOMBACH: Okay. Thank you, Mr. Chairman. Those are all my questions on the public record.

THE CHAIRPERSON: Thank you, Mr. Hombach. I think we should take a break, take ten (10) minutes. And, Mr. Meronek, you can resume your -- start your questioning after that. Is that okay? Okay, thank you.

--- Upon recessing at 3:40 p.m.
--- Upon resuming at 3:53 p.m.

THE CHAIRPERSON: I believe that everyone's in position to resume the proceedings. Mr. Meronek, please.

CROSS-EXAMINATION BY MR. BRIAN MERONEK:

MR. BRIAN MERONEK: Thank you, Mr. Chairman. Not because it's late in the day, but because I -- I would like to have some continuity to my questioning, I'm going to be doing most of it tomorrow. But I -- I have a few questions arising out of the direct today, more for clarification than anything else.

Mr. Rainkie, you had indicated that Centra wasn't seeking any change in the primary gas rates but that there would be an application filed in October for rates effective November 1?

MR. DARREN RAINKIE: Yes, as is our normal process.

MR. BRIAN MERONEK: So that's the quarterly -- quarterly rate application?

MR. DARREN RAINKIE: Yes, Mr. Meronek.

MR. BRIAN MERONEK: When do they get finalized? When will these -- these rates get finalized?

MR. DARREN RAINKIE: Sorry, when will the rate application be filed or the rates themselves finalized?

MR. BRIAN MERONEK: Well, they're all quarterly, and so they're interim, so when -- when is there going to be a final application made for the -- for the primary gas rates?

MR. DARREN RAINKIE: Well, I -- I suppose it would be the next General Rate Application or Cost of Gas application, whichever comes first.

MR. BRIAN MERONEK: And the other

question I have with respect to applications. You had indicated earlier that you don't forecast based on what you see today a GRA being required until 2017/2018, but that may change depending upon a new IFF that's being prepared?

MR. DARREN RAINKIE: Yes. I just wanted to make sure that we're clear that that is what we base our recommendations to our Board in terms of a rate application. I -- I don't think things will change significantly, but I just wanted to make sure that was clear, Mr. Meronek.

MR. BRIAN MERONEK: Just for communication purposes, when the Board approves the IFF, that is the Centra Board, does it go to the Public Utilities Board?

MR. DARREN RAINKIE: Yes. And -- and in this case, I think we'll be filing it soon after the Board -- the Hydro/Centra Board meeting, assuming that it gets passed.

MR. BRIAN MERONEK: And is that something that this Intervenor could get a copy of?

MR. DARREN RAINKIE: I think our intention was to put it on the public record in any case because we want to look at electric rates for April 1st, 2016. So I -- unless I'm missing something, we can come back if I am, I think it be already on the other side of your shop, so to speak.

MR. BRIAN MERONEK: No, it's just that -- that Centra makes the -- makes an assessment as to whether it needs to come in for rates.

Correspondingly, depending upon what an IFF says, perhaps the Board may want to initiate one (1) or an Intervenor. I'm not saying that that's the case, but we wouldn't know that if I didn't have the IFF.

MR. DARREN RAINKIE: Yes, I understand your point.

(BRIEF PAUSE)

MR. BRIAN MERONEK: I wasn't going to ask you any questions, Mr. Barnlund, but since you made fun of my shoes I'm going to -- I'm going to ask you a couple of zingers here. We -- we were talking about the -- the ying and the yang, the -- the rate shock versus rate stability. And Centra has obviously got quarterly primary gas rate changes.

You had mentioned something about Alberta doing it on a monthly basis?

MR. GREG BARNLUND: I believe that --

that system supply in Alberta is probably set on a monthly basis.

MR. BRIAN MERONEK: And -- and so is that for everything, or just primary gas?

MR. GREG BARNLUND: The -- the industry is -- is unbundled in Alberta, where ATCO and -- and the distribution utilities look after the distribution and another entity provides the system gas. I'm not fully aware -- I think at one (1) point in time the gas supplier was also billing for distribution rates to the bills they were sending to customers each month.

MR. BRIAN MERONEK: Okay. And I'm not promoting anything, but just musing. When you say we talk about rate shock and -- and spikes, and the consumer not being -- being confused, I know this isn't a -- a total 100 percent comparison, but clearly everyday when someone goes to the -- the gas pump and the prices change radically, in some -- some cases, the consumers -- they may be confused, but they get price transparency.

Is there any reason why for primary gas it couldn't be on a monthly basis and have it more corresponding with, you know, paying for what you consume as opposed to having intergenerational problems?

MR. GREG BARNLUND: Well, I think that the matter or the frequency of rate changes and adjustments has been looked at a couple of times in the past in this jurisdiction. And it was determined that four (4) times a year was -- was an adequate balance in terms of price transparency, and -- and stability for customers, and cost of -- of applications, and -- and kind of regulatory costs associated with that, too.

MR. BRIAN MERONEK: Mr. Sanderson, you were talking about 2013 and 2014 as not being unprecedented.

And you harkened back to 2000 and 2001, where there was a PGVA account of about $125 million?

MR. BRENT SANDERSON: Yes, the total of all of our purchased gas variance accounts. Yes, approximately $120 million.

MR. BRIAN MERONEK: And can you remind me, because I -- I don't remember, what kind of rate rider was put in pla -- or rate riders were put in place for that amount of money?

MR. BRENT SANDERSON: Subject to check, we instituted a three point six three (3.63) cent per cubic metre rate rider to recover the primary gas portion of that $120 million, which was about a hundred million of the total over a twenty-four (24) month period.

MR. BRIAN MERONEK: And did that cover everything?

MR. BRENT SANDERSON: There were other rate riders introduced that were handled in a more typical fashion for the various other accounts: supplemental distribution, PGVA. There were some capital tax impacts as a result of Centra having to carry such a large deferral balance on its books. But those were dealt with in a more typical one (1) year fashion.

MR. BRIAN MERONEK: And that was primarily because of the increasing cost of primary gas?

MR. BRENT SANDERSON: The hundred million dollar portion of the hundred and twenty (120) in total was a direct result of increases in Centra's primary gas costs, yes.

MR. BRIAN MERONEK: And that would have accrued over what period of time?

MR. BRENT SANDERSON: That was accrued over about a three (3) month period.

MR. BRIAN MERONEK: So was it cleared

out as soon as -- in terms of the incur -- occurrence of this 100 million plus of primary gas, how soon in relationship to that PGVA balance were rates -- rate riders put into place?

(BRIEF PAUSE)

MR. BRENT SANDERSON: Again, don't hold me to this exact date, but, subject to check, on the basis of my recollection, we had a pretty good sense by the middle of January what we were facing. And that twenty-four (24) month rider was implemented, to the best of my recollection, on June 1st of 2001.

MR. BRIAN MERONEK: Now, Mr. Rainkie, I don't want to get into the fray about construct because we've had this discussion in the past, but I am curious and not being mischievous.

You indicate that, with respect to income, that the pluses or minuses should even out over time, correct?

MR. DARREN RAINKIE: Yes, that's the concept, sir.

MR. BRIAN MERONEK: What do you mean by "over time"?

MR. DARREN RAINKIE: Well, I couldn't

put a number of years to it, sir, but certainly you wouldn't design a construct around one (1) or two (2) years.

I think the evidence that Mr. Drazen put together, a simple table to show that it worked out plus or minus over a ten (10) year period. So, you know, over -- in the utility business, we have long -- a long outlook. We don't look at things from a one (1) or two (2) year snippet.

MR. BRIAN MERONEK: And so if you -- if I understand you correctly, Mr. Drazen was saying that things evened out over about ten (10) years?

MR. DARREN RAINKIE: Yeah. I think what he was saying there is that, related to the net income target of 3 million, the actual results, even with all the volatility that we face, was reas -- was within a reasonable expectation of that target.

MR. BRIAN MERONEK: And, Ms. Stewart, you mentioned that -- that the NEB, in talking about what TransCanada Pipeline might do with unfettered discretionary pricing, indicated that it would be rare that TCPL would charge above 300 percent above the bid floor.

Did I get that correctly?

MS. LORI STEWART: Yes, that's

correct.

MR. BRIAN MERONEK: And do you know where NEB got that number? Was it something that TCPL committed to on the record?

(BRIEF PAUSE)

MS. LORI STEWART: My recollection is that the 300 percent number was introduced on the record by a mainline shipper, ANE, Alberta Northeast. But I would -- I would need to check that.

MR. BRIAN MERONEK: But as you sit here today, it wasn't something that TCPL committed to?

MS. LORI STEWART: Well, TCPL didn't know that the NEB was going to grant it unfettered pricing discretion, so there was no discussion in the RH-3 2011 proceeding about how TransCanada might exercise unfettered pricing discretion.

MR. BRIAN MERONEK: The only information that the NEB had was a comment made by a shipper that it -- they couldn't see it above 300 percent.

Is that -- do I get that correctly?

MS. LORI STEWART: Well, the decision

is -- it's over two hundred (200) pages long. So I would like the opportunity to go back and -- and revisit.

My recollection is that in the Board's findings as opposed to what it ordered there was mention that the Board itself did not expect TransCanada to be in a position to set bid floors any greater than 300 percent, you know, very often. But I'll go back and have a look tonight.

MR. BRIAN MERONEK: Sure. Appreciate that. It's just that you -- you will concede, or -- or maybe not, that TCPL never committed to a 300 percent maximum.

MS. LORI STEWART: I was providing some context for the question that I received from Board counsel.

So as I mentioned, there would have been no reason for TransCanada to comment on how it might exercise something that it -- it had not requested, or applied for.

MR. BRIAN MERONEK: But after the decision, did TCPL commit to a maximum amount?

MS. LORI STEWART: No. TransCanada has not committed to a maximum amount. Centra answered that question in one of its Information

Request responses.

MR. BRIAN MERONEK: So would it be fair to say that -- that someone couldn't take with any degree of confidence that the 300 percent meant anything to anybody? Maybe it's better put this way.

Did Centra get comfort from that statement from the NEB that it felt that the 300 percent wouldn't be exceeded?

MS. LORI STEWART: No. Centra did not take comfort in that. Had it taken comfort in a 300 percent level, we would not have entered the market in the fashion that we did post RH-3 2011 decision, and I'll walk -- walk the panel through that tomorrow.

(BRIEF PAUSE)

MR. BRIAN MERONEK: And I wasn't clear -- you were asked as to what steps were taken, my words, after the decision as to what TCPL might do with respect to its pricing of short-term transportation, and you indicated that there was a mainline tolls task force.

Was it that task force that -- that determined from TCPL that it was going to price short-term transportation to make it unec -- uneconomical for anybody?

MS. LORI STEWART: There were a series of communications from TransCanada post-decision, so I recall there being a discussion of its intentions around short-term firm in mainline tolls task force meeting in April, and then again at a TransCanada meeting in May. In fact, it was the same day in May that TransCanada filed its review and vary application.

So it was on -- in both of those circumstances that TransCanada clearly conveyed its intentions as it related to withholding of short-term firm transport, certainly from captive markets.

MR. BRIAN MERONEK: And for the record, that would be May -- April or May of 2013?

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

MR. BRIAN MERONEK: Now, there was an undertaking asked to get any minutes or documents relating to advising or briefing senior management with respect to the possibility about out-of-path diversions being eliminated. And -- and, Mr. Czarnecki, I think you said something about, Subject to any litigation. I wasn't quite clear what you were referring to.

MR. BRENT CZARNECKI: I'll try and help you. I think part of the analysis may have been contained directly within my recommendation that went to the executive committee

(BRIEF PAUSE)

MR. BRIAN MERONEK: Just one (1) question, Ms. Stewart. Did I get the -- your evidence correctly that the Eastern LDCs agreed with TransCanada pipeline that its mainline pricing discretion would last until 2020?

MS. LORI STEWART: The Eastern Canadian LDC's contractually committed to supporting pricing discretion on the mainline at least until the end of 2020.

MR. BRIAN MERONEK: And when was that?

MS. LORI STEWART: It was part and parcel of the settlement agreement reached between TransCanada and the Eastern Canadian LDCs. And that would have been reached in September of 2013 at a high level, and then more detailed contractual term sheets rolled out about two (2) months later.

MR. BRIAN MERONEK: Did the settlement have to be endorsed by the NEB, or was it effective as of September 2013?

MS. LORI STEWART: It had to be endorsed by the NEB. And it was in the RH-1 2014 proceeding that occurred last fall, in the fall of 2014.

MR. BRIAN MERONEK: Thank you, panel. Those are my questions for today.

THE CHAIRPERSON: I believe that ends today's proceedings, unless I hear from Mr. Czarnecki or Mr. Hombach. No. So that's it.

Thank you very much, everyone. We'll see each other again tomorrow morning at nine o'clock. And a reminder for the record that tomorrow this session is a closed session for consideration of the CSI information.

So have a good evening, everyone. We'll see you again tomorrow. Thank you.

--- Upon adjourning at 4:18 p.m.

Certified Correct,

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Sean Coleman, Mr.