CENTRA GAS MANITOBA INC.
2015/16 COST OF GAS APPLICATION
GAS SUPPLY & COSTS

INDEX

Appendices

Schedules

See the attached Schedule Index

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3.0 OVERVIEW

Centra's mandate is to acquire, manage and distribute supplies of natural gas to meet the Manitoba market requirement in a safe, cost-effective, reliable and environmentally appropriate manner. The cost of gas is the most significant cost that Centra incurs and is regulated, with the exception of Fixed Rate Primary Gas Service ("FRPGS"), on a pass-through basis. Gas costs are passed on to customers in their rates without any mark-up or profit to Centra. To ensure that only the cost of gas, no more and no less, is passed on to customers, Centra maintains a number of Purchased Gas Variance Accounts ("PGVA"), which record the differences between the cost of gas embedded in sales rates and the actual cost of gas incurred. These differences are periodically either refunded to or collected from customers by way of rate riders that either decrease (i.e., refund to customers) or add to (i.e., recover from customers) the base sales rates and form part of the billed rates that are charged to customers.

In this Application, Centra is seeking final approval of actual gas costs of $205.6 million incurred in the 2012/13 Gas Year and $343.5 million incurred in the 2013/14 Gas Year, as well as approval of outlook gas costs for the current 2014/15 Gas Year in the amount of $238.9 million. Centra is also requesting approval to implement rate riders to recover $35.4 million of prior period non-Primary Gas deferral balances over the course of the 2015/16 Gas Year. A discussion of the actual and outlook gas costs, as well as the timing of the recovery of the resulting prior period gas cost deferral balances follows in Sections 3.4 through 3.6.

This Tab provides a description of:

1. Centra's gas supply, transportation and storage portfolio;
2. The changes Centra has made to its gas supply, transportation and storage portfolio since its 2013/14 General Rate Application ("GRA");

3. The numerous developments in matters related to TransCanada Pipelines Limited ("TCPL") and their impacts on Centra;
4. The actual gas costs incurred and the resulting gas cost deferral balances for the 2012/13, 2013/14, and 2014/15 Gas Years for which Centra seeks approval as part of this Application; and
5. The forecast of gas costs for the 2015/16 Gas Year for which Centra also seeks approval as part of this Application.

3.1 CENTRA'S GAS SUPPLY, TRANSPORTION & STORAGE PORTFOLIO

Centra's gas supply, transportation and storage portfolio ("Gas Portfolio"), which is used to serve natural gas customers in Manitoba, consists of natural gas supplies and the associated transportation and storage arrangements.

The total realized cost of Centra's Gas Portfolio in 2012/13 was $205.6 million, as shown below and described in greater detail in Schedule 3.0.0. A detailed breakdown of these costs is provided in Section 3.4, which describes the gas costs incurred and resulting gas cost deferral balances for the 2012/13, 2013/14 and 2014/15 Gas Years.

Figure 3.1 - 2012/13 Gas Year

Supply Costs	$154.4 million
[redacted]	
Fixed Transportation & Storage Costs	$47.0 million
[redacted]	
Variable Transportation & Storage Costs	$6.8 million
Other Costs/(Revenue)	($2.6 million)
TOTAL	**$205.6 million**

The total realized cost of Centra's Gas Portfolio in 2013/14 was $343.5 million, as shown below and described in greater detail in Schedule 3.3.0. A detailed breakdown of these costs is also provided in Section 3.4.

Figure 3.2 - 2013/14 Gas Year

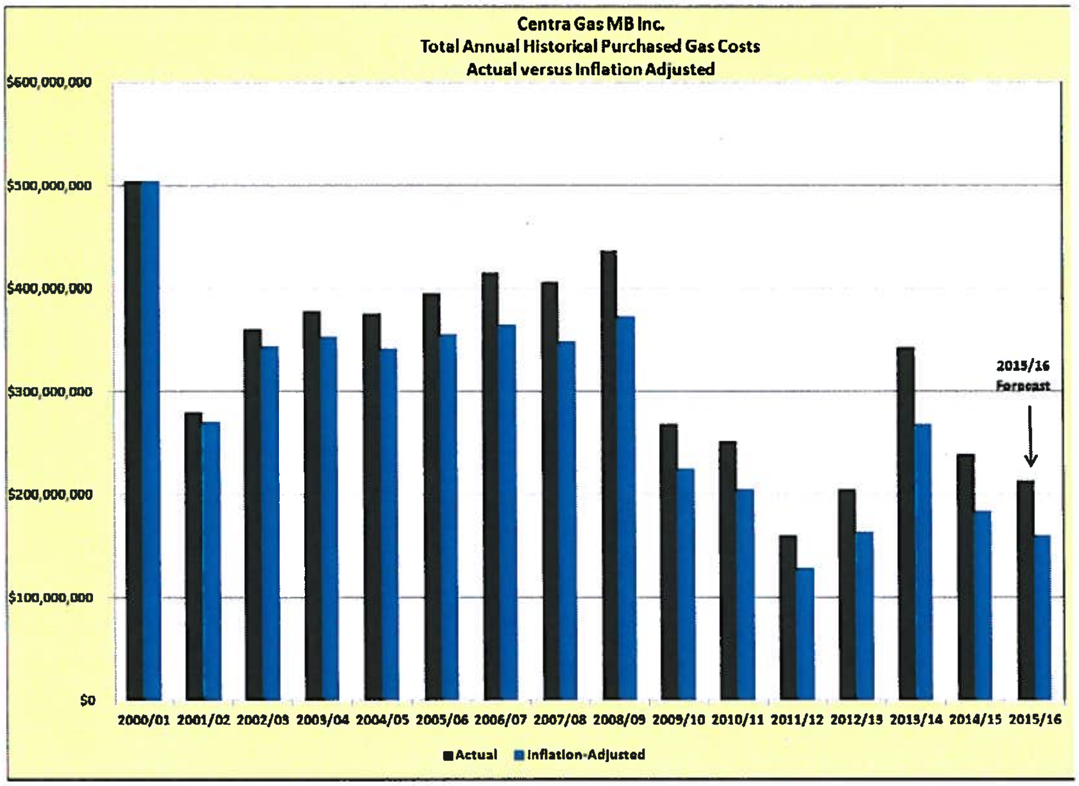
Supply Costs	$280.7 million
[redacted]	
Fixed Transportation & Storage Costs	$54.6 million
[redacted]	
Variable Transportation & Storage Costs	$13.0 million
Other Costs/(Revenue)	($4.8 million)
TOTAL	**$343.5 million**

Centra's Gas Portfolio costs in the 2013/14 Gas Year were significantly higher than the year prior but, when placed in historical context, reflect several realities:

1. Significantly higher natural gas consumption by customers in response to one of the coldest Manitoba winters in the last century;
2. High continental demand for natural gas and associated depletion of regional storage inventories, resulting from sustained very cold winter weather across much of North America;
3. The inherent variability in wholesale energy market prices (which are driven by weather to a significant degree); and,
4. A multitude of effects associated with the exercise of pricing discretion by TCPL on the Canadian Mainline (the "Mainline"), including dramatically increased short-term transportation tolls and their effects on commodity prices at interconnected downstream market hubs.

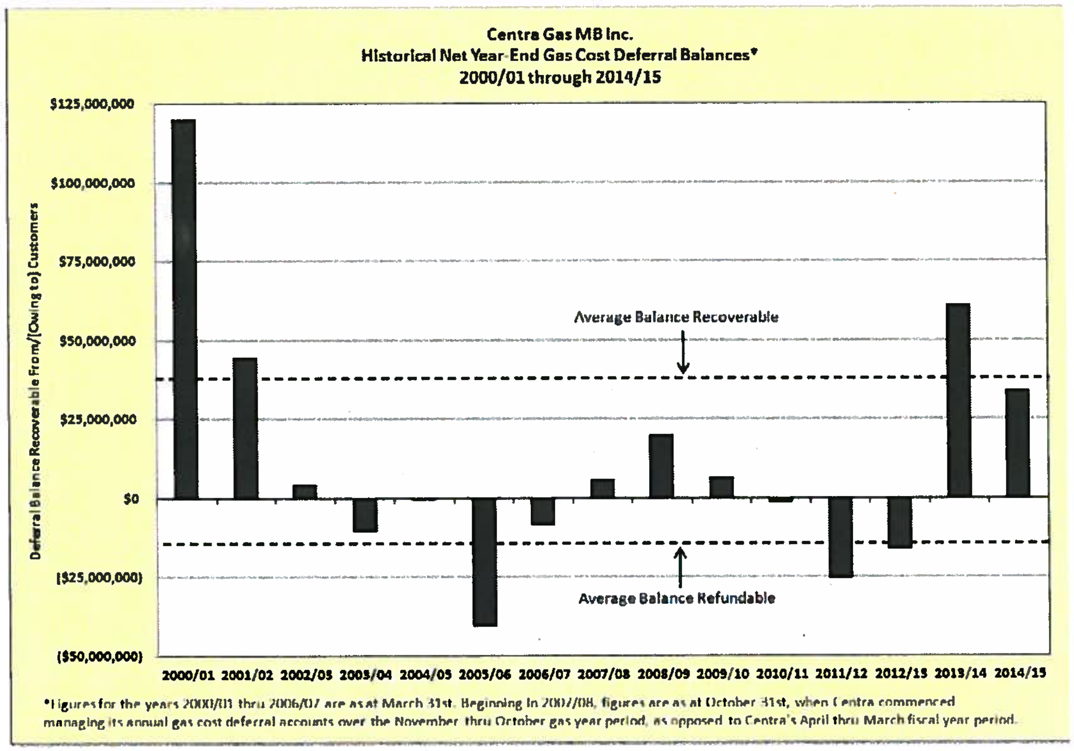
Centra's annual purchased gas costs since 2000/01 have ranged from $160 million to $504 million and, over this sixteen year period, 2013/14 ranked as the ninth highest level of annual expenditures. A graphic representation of Centra's historical gas cost experience is provided in the following figure. A more complete discussion is contained in Section 3.7.1 which provides Centra's natural gas market analysis.

Figure 3.3



While the Supplemental Gas deferral account balance encountered in 2013/14 is significant, such levels are not unprecedented. The following figure shows the level of all deferral account balances in each of the years since 2000.

Figure 3.4



One of the most dominant influences driving the incurrence of higher than forecast gas costs in the 2013/14 Gas Year was extremely cold weather. On an effective heating degree day basis, the entire 2013/14 Gas Year was [redacted]% colder than normal, while the 2013/14 winter period was [redacted]% colder than normal. These cold weather conditions resulted in the need for Centra to purchase approximately 10.9 million GJ of Supplemental Gas supplies to serve its customers' needs during the January through March 2014 period (not including Alternate Supply Service volumes purchased for Interruptible customers). This compares to forecast, weather-normalized Supplemental Gas consumption of [redacted] GJ over this 3-month timeframe. The overall average unit cost of these supplies was $[redacted]/GJ relative to the approved Weighted Average Cost of Gas ("WACOG") of $[redacted] embedded in Centra's approved Firm Supplemental Gas base rate during this time. This difference in unit costs resulted in a Supplemental Gas PGVA balance of $42 million owing to Centra at October 31, 2014.

The accumulation of this 2013/14 Supplemental Gas PGVA balance was predominantly the result of dramatic increases in winter natural gas prices at market hubs served either directly or indirectly by the TCPL Mainline. Gas prices were driven to a significant degree by TCPL's exercise of the unlimited pricing discretion granted to it by the National Energy Board ("NEB")[1]. During the months of January through March 2014, TCPL set its minimum Interruptible Transport ("IT") bid floors on the Mainline as high as 55 times its daily equivalent Firm Transportation ("FT") tolls. Combined with very cold weather and the resulting high demand and depletion of storage inventories in North America, these high IT bid floors contributed to high natural gas commodity prices at Mainline hubs such as Emerson, as well as other hubs in the region including MichCon and Chicago, which are interconnected to the Mainline via the Great Lakes Gas Transmission ("GLGT") and ANR Pipeline ("ANR") systems.

[redacted]

Figure 3.5

Gas Year	Pre-Contracted Firm Capacity
2011/12	407,651 GJ/day
[redacted]	

Other features of the 2013/14 Gas Portfolio that were used to minimize gas costs during the 2013/14 winter include the following:

[redacted]

[1]Mainline pricing discretion for short-term discretionary transportation services (IT and STFT) is unlimited with respect to the bid floors that TCPL can set for these services, with the exception that STFT bid floors cannot be set at a discount to annual FT tolls.

[redacted]

[redacted]

[redacted]

[redacted]

Centra also mounted a significant intervention in the recent RH-001-2014 hearing before the NEB on the matter of TCPL's Application for Approval of its Mainline 2015-2030 Settlement. A key part of Centra's intervention was to oppose the continuation of TCPL's unlimited pricing discretion on the Mainline on the basis that the secondary market did not constrain TCPL's pricing discretion in the manner anticipated by the NEB in its RH-003-2011 Decision.

The total outlook cost of Centra's Gas Portfolio in 2014/15 is $238.9 million, as shown below and described in greater detail in Schedule 3.6.0. A detailed analysis of these costs is provided in Section 3.4, which describes the gas costs incurred and resulting gas cost deferral balances.

Figure 3.6 - 2014/15 Gas Year

Supply Costs	$175.7 million
[redacted]	
Fixed Transportation & Storage Costs	$62.6 million
[redacted]	
Variable Transportation & Storage Costs	$4.7 million
Other Costs/(Revenue)	($4.2 million)
TOTAL	**$238.9 million**

In Order 112/12, the PUB approved the fixed costs of Centra's portfolio of natural gas storage and related inter-state transportation contracts with ANR and GLGT. [redacted]

3.1.1 Gas Supplies

The two components of gas supplies in Centra's portfolio are Primary Gas and Supplemental Gas. Centra also periodically provides Alternate Supply Service for Interruptible customers.

Primary Gas

Primary Gas is natural gas received from Western Canadian sources, whether supplied by Centra, by marketers through the Western Transportation Service ("WTS"), or by contractual arrangements referred to as Primary Gas Delivered Service. The costs captured in the Primary Gas PGVA are outlined in Section 3.4.1.

Primary Gas – Centra Supply

Centra purchases the majority of its Primary Gas at the AECO hub and at the Alberta border ("Empress") under a two-year gas supply contract with ConocoPhillips Canada Marketing and Trading ULC ("ConocoPhillips") for the period from November 1, 2014 to October 31, 2016. This contract was executed following a comprehensive Request for Proposal (RFP) process conducted earlier in 2014, and has been filed in confidence with the PUB. Prior to November 1, 2014, Centra purchased the majority of its Primary Gas at Empress, also under a two-year supply contract with ConocoPhillips. [redacted]

[redacted]

[redacted]

[redacted]

Primary Gas – Marketer Supply (WTS)

Manitoba natural gas customers may elect to purchase their Primary Gas directly from an independent gas marketer, instead of Centra. Centra facilitates the transportation of these gas supplies by way of its WTS. The customer arranges, through a marketer, a source of natural gas in Western Canada, which Centra receives at Empress. Centra is responsible for transporting, storing and distributing the Primary Gas acquired by the marketer on behalf of the customer. The price of that Primary Gas is negotiated between the marketer and the customer and is not subject to review or approval by PUB. Centra also provides an optional Agency, Billing and Collection ("ABC") Service to bill the Primary Gas costs on behalf of a marketer to its customers.

The following table provides the number of WTS customers and Maximum Daily Quantity ("MDQ") of Primary Gas for WTS supply as of November 1, 2012, November 1, 2013 and November 1, 2014.

Figure 3.7

	Number of Customers	Maximum Daily Quantity (GJ/day)
November 1, 2014	16,500	14,799
November 1, 2013	16,300	18,926
November 1, 2012	17,900	20,058

Primary Gas – Primary Gas Delivered Service

In addition to purchases under Centra's Primary Gas supply contract and Primary Gas supplied by marketers as part of the WTS, Centra may also execute contractual arrangements for Primary Gas Delivered Service, whereby a counterparty delivers gas directly to the Manitoba market. [redacted]

<u>**Supplemental Gas**</u>

Supplemental Gas is natural gas sourced on a daily, monthly or seasonal basis to serve the Manitoba market's peak day and seasonal requirements, and includes U.S. Supplies and Peaking Delivered Services.

[redacted]

Supplemental Gas – Peaking Delivered Services

Peaking Delivered Services, in which supplies are delivered directly to Manitoba by counterparties for specified terms dependent upon forecasted and actual loads, are another source of Supplemental Gas.

Alternate Supply Service

Curtailment and/or the provision of Alternate Supply Service to Interruptible customers may be required to conserve storage inventories, or whenever demand is forecast to exceed Centra's firm deliverability. If supply is available for purchase and transport in the market (i.e., a delivered service to the MDA), Interruptible customers are offered Alternate Supply Service at prices that reflect the cost of obtaining this service. Prices and quantities are arranged in a very short time horizon and rarely more than a day in advance.

Gas Management Agreement with SaskEnergy

Centra acquired the assets of the Swan Valley Gas Corporation in 2014. The Swan Valley service area is not interconnected with Centra's existing distribution system infrastructure in Manitoba thus, the natural gas to serve the customers in this area of the Province continues to be purchased from SaskEnergy and delivered through the TransGas Limited ("TransGas") and Many Islands Pipelines (Canada) Limited ("MIPL") systems. Centra has a Gas Management Agreement with SaskEnergy for the sourcing, acquisition, nomination, delivery and balancing of gas supply requirements for the Swan Valley service area. These requirements are nominal relative to the total requirements of Centra's market, as they serve approximately 300 customers.

[redacted]

[redacted]

Figure 3.8

[redacted]

At the beginning of the winter, under the assumption of a normal weather year, natural gas is dispatched daily using Primary Gas, U.S. Supplies, Storage, and Peaking Delivered Services to meet both Firm and Interruptible requirements. As the winter progresses, Centra monitors the extent to which the weather has varied from normal and the resulting storage inventory levels. If it is determined that storage withdrawals are greater than planned, Centra would offer Alternate Supply Service to Interruptible customers (or curtail them as required) to conserve storage gas for the firm market, such that it would be able to supply the maximum year firm requirement from that point to the end of the winter. Alternate Supply Service or curtailment of Interruptible customers may also come into effect to ensure that the firm load is met during colder than normal weather on any particular day.

3.1.2 Transportation and Storage Arrangements

Canadian Mainline - Transportation

Primary Gas supplies purchased or received at Empress, either as Centra supply or WTS supply, are transported from Western Canada to Saskatchewan and Manitoba by way of [redacted]. The majority of Centra's customers receive natural gas service through meter stations on the Mainline in the MDA, while a relatively small number of customers in the Parkland area are supplied from a meter station that is located in Saskatchewan and is part of the Mainline's Southern Saskatchewan Delivery Area ("SSDA"). Please see Appendix 3.2 of Tab 3 for a map of these sections of the Mainline system.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

The inflows to the 2012/13 Transportation PGVA account are comprised of the transportation and storage costs associated with Centra's previous Gas Portfolio from November 1, 2012 to March 31, 2013, as well as the transportation and storage costs associated with the current Gas Portfolio from April 1, 2013 to October 31, 2013. The actual 2013/14 and 2014/15 Transportation PGVA inflows, along with the forecast inflows to the 2015/16 Transportation PGVA, are attributable solely to the transportation and storage costs associated with the current Gas Portfolio. Contractual demand levels and the operation of these Gas Portfolios, in relation to the Gas Years in question, are discussed in the following sections.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Any Manitoba load requirement in excess of Centra's firm deliverability is usually met through the purchase of incremental supplies delivered directly to Manitoba through Peaking Delivered Service arrangements. Interruptible customers are offered, subject to availability, Alternate Supply Service (or are curtailed as required) to conserve storage inventory, or whenever forecast demand exceeds Centra's firm deliverability.

3.1.3 Changes to Gas Portfolio since the 2013/14 GRA

Changes in Centra's Gas Portfolio since the 2013/14 GRA (filed in February 2013) are outlined below.

[redacted]

The RH-003-2011 Decision, effective July 1, 2013, impacted the natural gas market in a number of significant ways. At a high level, this Decision approved multi-year fixed FT tolls on the Mainline that the NEB deemed to be competitive, while providing TCPL a reasonable opportunity to recover Mainline costs given the increase in Mainline throughput which was forecast over the multi-year fixed toll term. This Decision also provided TCPL with unlimited discretion in the pricing of short-term services on the Mainline such as STFT and IT. This decision and other TCPL matters are discussed further in Section 3.3.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

3.2 CAPACITY MANAGEMENT PROGRAM & RESULTS

3.2.1 Capacity Management Program & Transactions

The objective of Centra's Capacity Management ("CM") Program is to optimize use of the Gas Portfolio so as to minimize its related costs, while first and foremost ensuring Centra's ability to meet the Manitoba market requirement. If an asset is deemed to be excess for a day/month/season, Centra assesses factors such as changing prices and basis differentials in the various markets, along with potential counterparty interest in the transaction in order to determine the potential value associated with any particular arrangement, as well as the potential risk inherent in the transaction. The market value of capacity is dependent on the market value of natural gas delivered to a particular market area and, as such, is subject to day-to-day and intra-day fluctuations.

In order to generate CM revenue there must be a market participant willing to pay a price that covers any incremental costs involved in the transaction, provide some recovery of the underlying cost of the asset, and cover Centra's credit risk exposure as a result of the transaction.

Due to fluctuations in weather, pricing and basis differentials, it is difficult to forecast the revenue that may be earned through CM transactions. The five-year rolling average of actual CM revenue serves as a benchmark to estimate the CM credit to be embedded prospectively in customers' transportation rates each year in advance of the realization of these revenues.

Centra relies on two general types of CM transactions. The first is a Capacity Release transaction, which is the temporary release of Centra's transport capacity to a counterparty. This can take the form of:

i) An assignment of capacity (i.e., an outright pipeline release, or a pipeline release with a delivery obligation [commonly referred to as an asset management arrangement]); or

ii) A diversion, whereby Centra agrees to transport another party's gas to a predetermined point for a fee. All revenue in excess of incremental costs associated with the diversion is booked as CM revenue and serves to reduce fixed transportation costs.

The second type of CM transaction is a physical exchange of natural gas. These transactions provide for the delivery of natural gas to Centra at the Manitoba market or other points by a counterparty, in exchange for the same volume delivered by Centra to the counterparty at a mutually agreed upon alternate transaction point. The value of exchanges depends on basis differentials at the time of the transaction. One example is a storage exchange, which is done in lieu of transporting the equivalent volume from storage to the Manitoba market, and is limited to the amount that would normally be transported by Centra on a particular day. [redacted]

3.2.2 Capacity Management Results

Please find below a description of CM revenue earned in the 2012/13 and 2013/14 Gas Years. This discussion compares actual CM results to the previous 5-year rolling average of actual CM revenue, and differs from the discussion of CM revenue in section 3.4.3 of the Application, which compares 2012/13 and 2013/14 actual CM results to the $6.3 million approved forecast of CM revenue that is embedded in currently approved rates.

During the 2012/13 Gas Year, Centra earned $3.0 million of CM revenue (excluding carrying costs). This amount was $3.3 million less than the forecast of $6.3 million, which was calculated using the five-year rolling average of actual results for the period from November 1, 2007 through October 31, 2012. During the 2012/13 Gas Year, [redacted]

[redacted]

During the 2013/14 Gas Year, Centra earned $5.2 million in CM revenue (excluding carrying costs), which equalled the forecast amount of $5.2 million based on the updated five-year rolling average of actual results for the period from November 1, 2008 through October 31, 2013. [redacted]

The amount of CM revenue embedded in the 2014/15 Gas Year outlook is $4.6 million, which is based on actual CM revenue to the end of February 2015 and outlook results for the remainder of the 2014/15 Gas Year. This amount of $4.6 million is $0.6 million lower than the five-year rolling average of actual results for the period from November 1, 2009 through October 31, 2014, which totals $5.2 million.

In Order 112/12, issued on August 23, 2012 in respect of Centra's Transportation & Storage Portfolio Application, the PUB directed Centra to provide the monthly totals of its CM revenue broken down by type of transaction and reflected as a percentage of the costs associated with the operation of each component of Centra's portfolio. Attached as Appendices 3.7 and 3.8 to Tab 3 are detailed CM reporting for the 2012/13 and 2013/14 Gas Years.

3.3 TCPL AND RELATED MATTERS

The Mainline physically transports all natural gas supplies that are consumed in Centra's service territory[2]. Centra's gas supply planning and operations are significantly

[2] Centra recently acquired the assets of Swan Valley Gas Corporation ("SVGC") and the franchise to serve certain

influenced and affected by the current and future business environment of the Mainline. For more than a decade, the Mainline has experienced significant business challenges. A persistent trend of shipper de-contracting on the Mainline has resulted in the current situation where, on certain segments of the Mainline, throughput is far less than capacity.

A number of important regulatory proceedings have either taken place before the NEB or come into effect since Centra was last before the Public Utilities Board of Manitoba in June of 2013. Centra discusses TCPL and related matters below, by proceeding.

RH-003-2011 (Mainline Business and Services Restructuring Application)

The RH-003-2011 Decision by the NEB, which came into effect on July 1, 2013, impacted the natural gas market in a number of ways. The Decision approved multi-year fixed FT tolls on the Mainline at levels that the NEB deemed to be competitive, while providing TransCanada a reasonable opportunity to recover its Mainline costs given the increase in Mainline throughput which was forecast over the multi-year fixed-toll term. The NEB established the FT toll from Empress, Alberta to Dawn, Ontario at $1.42/GJ, as compared to the then interim toll of $1.89/GJ. The NEB fixed this toll to remain in effect through December 31, 2017, subject to certain potential off-ramps being triggered. Centra's FT tolls as of July 1, 2013 were as follows:

Figure 3.9

TCPL Mainline Tolls	Pre-July 1, 2013 Tolls	July 1, 2013 Tolls
Empress to the MDA	$0.64/GJ/day	$0.54/GJ/day
Empress to the SSDA	$0.36/GJ/day	$0.40/GJ/day
Emerson to the MDA and STS	$0.15/GJ/day	$0.16/GJ/day

The NEB approved the Mainline's return on equity at 11.5% on a 40% deemed equity ratio. The NEB also approved an incentive mechanism which would further increase the

Rural Municipalities, Towns and a Village. There are a total of 259 active customers in these new franchise territories. These customers' consumption represents approximately one-tenth of one per cent of Centra's overall annual sales requirement. The SVGC system is not interconnected with the existing Centra distribution system in Manitoba and is distant from the Mainline. This minor exception is noted here for completeness.

Mainline's profits if annual net revenues were higher than forecast. The NEB developed a streamlined regulatory process for the Mainline to address new service and pricing proposals in a timelier manner. The NEB approved all of TransCanada's proposed changes to the Mainline's cost allocation and the elimination of both FT-RAM and toll zones on the Mainline. The NEB also gave unlimited discretion to TransCanada with respect to how it prices IT and STFT services on the Mainline.

The RH-003-2011 Decision provided clarity from the NEB on two key issues. Firstly, the NEB confirmed that TCPL bears fundamental risk on the Mainline if larger than forecast cost deferrals occur and secondly, the NEB outlined that TCPL is not compelled by statute to provide service to customers.

TCPL was not satisfied with the RH-003-2011 Decision and on May 1, 2013 filed an Application for Review and Variance. Included in the Review and Variance were new amendments to the Mainline tariff (the "Tariff Proposals"). On June 11, 2013 the NEB issued a letter and dismissed the Review and Variance in its entirety. However, the NEB deemed the Tariff Proposals to be a separate application to amend the Mainline tariff and advised that it would hear the merits of the proposal in a separate proceeding.

RH-001-2013 (Mainline Tariff Proposals)

On June 17, 2013 TCPL filed its Application for Approval of Tariff Proposals (RH-001-2013), including requests for approval of:

- Implementation of modification to the terms applicable to Diversions and Alternate Receipt Points ("ARPs"), such that they should only be available within the primary contracted FT path;
- Elimination of the overrun feature of STS, which allows STS shippers to exceed their daily contractual quantity entitlement on a non-firm basis and at the prevailing toll;
- Removal of the prescriptive Tariff language pertaining to the timing and duration of STFT and Short Term Short Notice (ST-SN) open seasons; and
- Amendment of the renewal provisions associated with firm Mainline services with respect to situations of major expenditures, significant maintenance requirements, or opportunities to re-deploy substantial existing assets.

Centra intervened in the RH-001-2013 proceeding and participated in the associated regulatory review process. Centra's opposition to TCPL's application was primarily related to the proposed tariff modifications to the terms applicable to Diversions and ARPs.

On October 10, 2013, the NEB issued its RH-001-2013 Letter Decision followed by its Decision with Reasons on November 25, 2013, in which the NEB denied the proposed amendments to the Tariff in respect of ARPs and Diversions, STS overrun and STFT/ST-SN open season provisions, but amended the renewal provisions for firm Mainline services to require contract holders to provide TCPL with two years' notice of their intention to renew (instead of the six month renewal notice provision that existed prior to the Decision).

MH-001-2013 (Pipeline Abandonment)

In January 2008, the NEB identified a proposed approach for the Land Matters Consultation Initiative ("LMCI"), one of the objectives of which was to consider the optimal way of ensuring that funds are available when pipeline abandonment costs are incurred. In May 2009, the NEB issued its RH-002-2008 Decision, which set out principles, a framework and a five-year action plan, with the goal of having all NEB-regulated pipelines begin to collect funds to pay for pipeline abandonment commencing January 1, 2015.

In November 2012, the Abandonment Cost Estimates ("ACE") proceeding (MH-001-2012) took place in which the NEB considered the reasonableness of each company's pipeline abandonment cost estimates. In January 2014, the Set-Aside Mechanism and Collection Mechanism ("SAM-COM") proceeding (MH-001-2013) took place before the NEB for Group 1–Gas pipelines. The NEB approved at "trust" as the mechanism for the set-aside of funds for future abandonment for most pipelines, as well as a framework for the related collection mechanisms. Centra intervened in the MH-001-2013 proceeding and participated in the associated regulatory process.

TCPL received approval to collect Mainline abandonment costs over a 25 year period through a distance-based surcharge applied to all Mainline transportation services per GJ of contracted capacity. NGTL proposed a collection period of 30 years as its competitive position and ability to attract and retain supply suggested that 30 years would be appropriate. NGTL abandonment costs are also being collected through a surcharge applied to each GJ of contracted capacity.

On November 25, 2014, the Mainline made its compliance filing related to the MH-001-2013 Decision, including SAM-COM and Statement of Investment Policies and Procedures ("SIPP") details. The current ACE for the Mainline is $2.53 billion to be collected over 25 years. The annual contribution amount (ACA) for the Mainline is $135 million, which results in abandonment surcharges (which are additive to tolls and commenced on January 1, 2015) for Centra of:

- Empress to the MDA FT: $0.05/GJ/day
- Empress to the SSDA FT: $0.03/GJ/day
- Emerson to the MDA FT and STS: $0.01/GJ/day

On November 25, 2014, NGTL made its compliance filing related to the MH-001-2013 Decision. The current ACE for NGTL is $2.18 billion to be collected over 30 years. The annual ACA for NGTL is $97 million, which results in an abandonment surcharge (which is additive to the toll and commenced on January 1, 2015) for Centra of:

- AECO to Empress FT-D: $0.01/GJ/day

The NEB also directed that if there is a change in circumstances between NEB-mandated reviews that materially affects the annual contribution amount (ACA), then the company must revise its ACA. Circumstances that may impact the ACA include, but are not limited to, changes in tolling methodology and an increase or decrease of rate base.

<u>RH-001-2014 (Mainline Settlement)</u>

On December 20, 2013 TCPL filed an Application for Approval of Mainline 2013-2030 Settlement (the "Settlement") with the NEB. TCPL requested approval of an agreement that it reached with Enbridge Gas Distribution, Union Gas Limited, and Gaz Metro Limited Partnership (the "Eastern Canadian LDCs"). TCPL and the Eastern Canadian LDCs indicated that while the RH-003-2011 Decision resulted in some important changes on the Mainline, it did not address the financial implications for TCPL of Mainline facilities additions. As a result, disputes arose between TCPL and the Eastern Canadian LDCs over the desire for new infrastructure in the Eastern Triangle portion of the Mainline, which the Settlement resolved.

The key stated objective of the Settlement for TCPL was to provide a reasonable opportunity for Mainline cost recovery. The key stated objective for the Eastern Canadian LDCs was to create an environment that would facilitate the investment required to support the efficient development of natural gas infrastructure in Eastern Canada. A key component of how these objectives were proposed to be achieved is by segmenting the Mainline into the Eastern Triangle ("ET") and the Western Mainline by the end of 2020. The Western Mainline is comprised of the Prairies Line and the Northern Ontario Line ("NOL"). The highlights of what the Settlement proposed are as follows:

- The Mainline System will be segmented for tolling purposes so that the ET rate base and cost of service are separated from the Western Mainline rate base and cost of service.
- Capital expansions in the ET will be promptly pursued to meet market needs and will be added to the ET rate base and tolled on a rolled-in basis.
- A transitional Bridging Contribution will be paid by all Mainline Shippers for the 2015-2020 timeframe, which for Centra and other Western Mainline shippers represents an additional 12% increase over and above RH-003-2011 Compliance Tolls.
- The Western Mainline will be tolled independent of the ET after December 31, 2020 and Mainline Shippers using the ET will have no continuing obligation with respect to the costs of Western Mainline unless they use those portions of the Mainline System.
- The long term adjustment account ("LTAA") balance at December 31, 2020 will be allocated to the ET revenue requirement for 2021 and beyond (the LTAA is a deferral account used to capture differences between forecast and actual results).
- The continuation of pricing discretion for STFT and IT services on the Mainline for the entirety of the 2015-2030 settlement period.

Centra intervened in the RH-001-2014 proceeding and participated in the associated regulatory review process. On November 28, 2014, the NEB issued its Letter Decision followed by its Decision with Reasons on December 18, 2014. The NEB approved the following effective January 1, 2015:

- Mainline segmentation in principle at this time, but will continue to monitor the appropriateness of segmentation prior to its implementation. Should circumstances be significantly different closer to 2020, the NEB expects that the issue of segmentation post-2020 would be re-examined to determine if it remains appropriate. TCPL had sought irrevocable NEB approval of Mainline segmentation for the 2021-2030 period.
- The capacity capital additions allocated to the ET rate base.
- The proposed revenue requirements for 2015 to 2020, including tolls and other cost of service elements.
- Maintaining pricing discretion as established in the RH-003-2011 Decision, but will review the continued appropriateness of pricing discretion for the 2018-2020 period in a future Mainline tolls application.
- TCPL's proposed toll design for 2015-2020, subject to the requirement that TCPL file two documents:
    1. RH-001-2014 compliance filing before March 31, 2015, which must include the following adjustments to the proposed tolls:
        - The allocation of the actual toll stabilization account (TSA) balance as of December 31, 2014 to the LTAA; and
        - All updates to revenue requirement and firm billing determinants as of December 31, 2014.
    2. 2018-2020 tolls application prior to December 31, 2017, which must include:
        - A review of revenue requirements for the 2018-2020 period;
        - A review of billing determinants, including contracted long-haul capacities to the ET;
        - A review of discretionary miscellaneous revenue forecasts for the 2018-2020 period; and
        - A discussion of any other material changes that would impact the operation of the Mainline during the 2018-2020 timeframe, including whether pricing discretion continues to be necessary for the Mainline, either on an integrated or segmented basis.
- A 10.1% ROE on a 40% deemed equity ratio.
- The applied-for incentive sharing mechanism.
- The 15-year minimum contract term requirement for expansion facilities.
- The term-up provision which outlines that if expansion facilities with an estimated cost exceeding $20 million are required, TCPL will give notice of this to all shippers

with existing FT contracts who could be affected by the design of the expansion facilities. Within 60 days, each shipper will have the option to extend the term of all or a portion of their applicable contract quantity for an additional period such that their new contract expiration date would be at least five years after the expected in-service date of the expansion facilities, thereby retaining their renewal rights. If a shipper does not elect to extend its contract term within 60 days, their contract will expire at the end of its existing term.

The NEB noted that TCPL proposed to allocate the LTAA balance to the ET rate base in 2021 and determined that this proposal was appropriate in the context of the package of gives-and-takes between TCPL and the Eastern Canadian LDCs. However, the NEB advised that a different allocation of the LTAA may be more appropriate based on the circumstances that exist when 2021 tolls are determined.

The NEB directed TCPL to initiate a comprehensive review of the non-public, shipper-specific information that TCPL's Mainline pricing desk has access to, including non-public information from TCPL's affiliates, and how this non-public information could, in theory and practice, influence the setting of bid floors for IT and STFT. TCPL was directed to provide remedies as to how it will prevent access to and use of non-public shipper-specific information in the setting of bid floors for these discretionary services. TCPL was ordered to consult with Mainline stakeholders on this matter and provide the results of its internal review and consultations with stakeholders to the NEB by March 31, 2015.

The RH-001-2014 Decision established TCPL Mainline toll design for the 2015-2020 period, subject to the 2018-2020 tolls application that TCPL must file prior to December 31, 2017. The resulting approved tolls, which represent a 12% increase for Centra compared to the multi-year fixed tolls established by the RH-003-2011 Decision, were implemented on an interim basis as follows effective January 1, 2015:

- Empress to the MDA FT: $0.60/GJ/day
- Empress to the SSDA FT: $0.45/GJ/day
- Emerson to the MDA FT and STS: $0.18/GJ/day

TCPL made its RH-001-2014 compliance filing on March 31, 2015, the forecast impact of which is a revised rate increase for Centra and other Western Mainline shippers of 8% (versus 12%) compared to the multi-year fixed tolls established by the RH-003-2011 Decision as outlined below:

- Empress to the MDA FT: $0.58/GJ/day
- Empress to the SSDA FT: $0.43/GJ/day
- Emerson to the MDA FT and STS: $0.17/GJ/day

[redacted]

The NEB has recently received comments on TCPL's compliance filing. Differences recorded due to the charging of higher interim tolls from January 1, 2015 until the RH-001-2014 compliance filing is reviewed and final tolls are established, will be captured in the LTAA. An update on this matter, including impacts on Centra's rates, will be included in Centra's pre-hearing update to be filed in fall 2015.

Interim NGTL 2015 Tolls

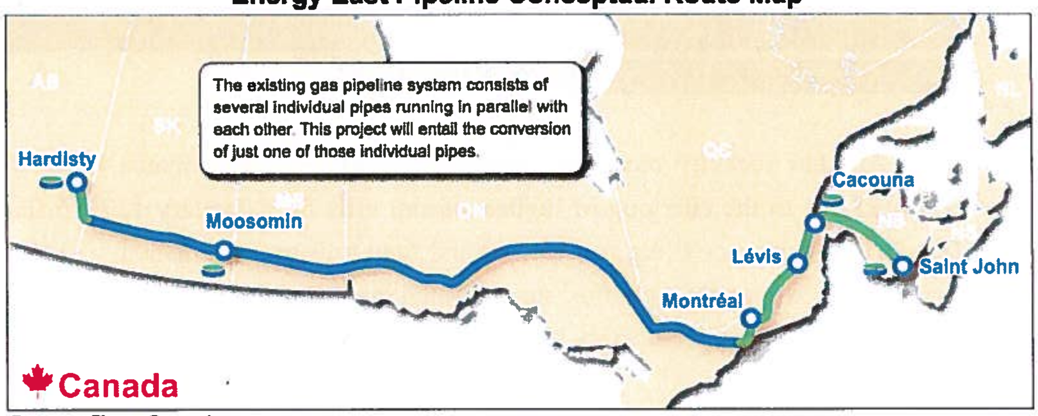
On October 31, 2014, NGTL filed its Application for Approval of Interim 2015 Rates, Tolls and Charges for the NGTL System commencing January 1, 2015. The applied-for tolls were implemented on an interim basis effective January 1, 2015. Approval was received from the NEB on April 14, 2015 for final tolls to be set at the same level as the interim tolls. [redacted]

Energy East

On October 30, 2014, Energy East Pipeline Ltd. filed an Application with the NEB for approval to construct and operate the Energy East Project, a 4,500 km crude oil pipeline system to transport oil from Alberta and Saskatchewan receipt points through Manitoba and Ontario to delivery points in Quebec and New Brunswick. The Energy East Project would be comprised of both new oil pipeline facilities and existing natural gas pipeline facilities, which would be transferred from TCPL to Energy East Pipeline Ltd. and converted from gas to oil service. Also on October 30, 2014, TCPL filed a related application for approval to construct and operate the Eastern Mainline Project ("EMP"), a 245 km natural gas pipeline from Markham, Ontario to Iroquois, Ontario. The Energy East Project and the EMP will be reviewed together in one proceeding by a single NEB Panel.

Figure 3.10

Energy East Pipeline Conceptual Route Map



Source: TransCanada

The proposed conversion facilities consist of portions of three sections of the Mainline between Burstall, Saskatchewan and Iroquois, Ontario, including:

- The Prairies Line: 940 km of pipeline from Burstall, SK (Station 2) to Ile des Chenes, MB (Station 41);
- The NOL: 1,640 km of pipeline starting at Ile des Chenes, MB (Station 41) to Station 116 near North Bay, ON.
- The North Bay Shortcut Line: 420 km of pipeline starting at Station 116 near North Bay, ON to Station 1401 near Iroquois, ON.

In early March 2015, Centra filed an Application to Participate ("ATP") as an intervenor in the Energy East proceeding. Centra's interests relate to the following issues:

1) The commercial, economic, supply and market impacts of the Energy East Project;
2) The commercial, economic, supply and market impacts of the Asset Transfer, including the need, economic feasibility and commercial impacts of the Eastern Mainline Project. This includes the appropriateness of the proposed capacity of the Eastern Mainline Project of 575 TJ/d; and
3) Transfer of Assets:
   i. The tests to be used to assess the sale and purchase of the assets;
   ii. The assets to be transferred and any terms to be included; and
   iii. The value that should be assigned to the facilities for the purposes of:
      - removal from the rate base of a portion of TCPL's natural gas Mainline; and
      - inclusion in the Energy East Project's toll calculations.

Over 1,800 ATPs were received by the NEB as of the original March 3, 2015 submission deadline. The NEB subsequently re-opened the ATP process from March 10-17, 2015 as the NEB website had experienced some technical difficulties for periods of time during the original ATP process. The process is now officially closed and the NEB has received more than 2,200 ATPs.

3.4 2012/13, 2013/14 & 2014/15 GAS YEAR COSTS AND GAS COST DEFERRALS OVERVIEW

This section provides the details of all gas costs and gas cost deferral balances for the 36-month period from November 1, 2012 to October 31, 2015. The 2012/13, 2013/14 and 2014/15 Gas Year costs are summarized in Schedules 3.0.0, 3.3.0, and 3.6.0 respectively. Purchased gas cost inflows totalled \$205.6 million for the 2012/13 Gas Year and \$343.5 million over the course of 2013/14, while the current outlook regarding the 2014/15 Gas Year projects costs of \$238.9 million.

In this Application Centra is seeking final approval of its final actual gas costs for the 2012/13 and 2013/14 Gas Years. The outlook of Centra's 2014/15 gas costs included in this application is based on actual results from November 1, 2014 through February 28, 2015 and outlook results for the period from March 1, 2015 through October 31, 2015, based on an April 2, 2015 futures market price strip. Centra intends to file a pre-hearing update of its 2014/15 gas costs prior to the commencement of the oral hearing to review this Application in the fall of 2015.

Centra is also seeking approval to implement rate riders to recover a projected October 31, 2015 net amount of $35.4 million of prior period non-Primary Gas cost deferral balances owing to Centra from customers as at October 31, 2015 over a 12-month period commencing November 1, 2015 and ending October 31, 2016.

The following sections 3.4.1 through 3.6 provide the details of all gas cost deferral balances for the period from November 1, 2012 through October 31, 2015.

3.4.1 2012/13, 2013/14 & 2014/15 Primary Gas PGVA's

The Primary Gas PGVA captures the cost of Primary Gas purchases from Western Canada flowing directly to the load on the TCPL Mainline, Primary Gas Delivered Services, Primary Gas withdrawn from storage to meet load requirements, compressor fuel on the TCPL system to transport Primary Gas purchases from Alberta to Manitoba and limited balancing agreement ("LBA") fees on the Mainline. Primary Gas supplies associated with Unaccounted-For-Gas ("UFG") requirements are removed from this account and transferred to the Distribution PGVA.

This account operates on a continuum, with the resulting balance at the end of each gas quarter being amortized through a revised Primary Gas rate rider as part of the quarterly Primary Gas RSM. As a result, there are no approved annual Primary Gas PGVA cost inflows and Weighted Average Cost of Gas ("WACOG") outflows against which to compare actual results. Therefore, no variance analysis of the Primary Gas PGVA is provided.

Centra is not seeking any change to Primary Gas rates in this Application as Quarterly Primary Gas rates are adjusted using the Rate Setting Methodology ("RSM") approved by the PUB. Through this Application however, Centra requests final approval of actual Primary Gas costs for the period from November 1, 2012 to October 31, 2014 inclusive. As the final gas costs for the 2014/15 Gas Year will not be available until after the close of the gas year, Centra will seek final approval of these costs at a subsequent proceeding.

Schedule 3.1.1 (a), (b) and (c) set out respectively the monthly details for the Primary Gas PGVA for the 2012/13, 2013/14 and 2014/15 Gas Years. The October 31, 2015 outlook balance, including carrying costs, is $1.0 million owing to customers. The cost inflows and outflows are based on actual results to February 28, 2015 and an outlook for the period of March 1, 2015 through October 31, 2015 based on an April 2, 2015 futures market price strip.

3.4.2 2012/13, 2013/14 & 2014/15 Supplemental Gas PGVA's

Supplemental Gas is natural gas provided from sources other than Primary Gas, including, but not limited to, U.S. Supplies, Supplemental Gas withdrawn from storage and Peaking Delivered Services. Supplemental Gas is required to serve the load when the Manitoba market requirement exceeds the combined deliverability of Centra's sources of Primary Gas.

Schedule 3.1.2 (a) sets out the monthly detail for the 2012/13 Supplemental Gas PGVA. The cost inflows and outflows are based on actual results from November 1, 2012 to October 31, 2013. The inclusion of carrying costs through to the end of the 2013/14 Gas Year results in a $3.2 million balance owing to Centra as at October 31, 2014.

Schedule 3.1.2 (b) shows a comparison of actual and approved 2012/13 Supplemental Gas PGVA inflows and outflows. The major contributors to the residual balance are as follows:

- $[redacted] owing to Centra pertains to higher than forecast Supplemental Gas purchases made during October 2013 that was a result of colder than normal weather. Actual purchases for the month of October (excluding Alternate Supply Service) totaled approximately [redacted] GJ in comparison to the weather normalized forecast of [redacted] GJ.
- Lower than forecast average Supplemental Gas purchase costs accounts for a $[redacted] balance owing to customers. The average unit cost of Supplemental Gas purchases, excluding Alternate Supply Service for Interruptible customers, was $[redacted]/GJ in comparison to the forecast average unit cost of $[redacted]/GJ (line 21 of Schedule 3.1.2 (b)). This average Supplemental supply price differential, multiplied by the [redacted] [redacted] GJ of Supplemental Gas purchases to serve system supply requirements (line 19 of Schedule 3.1.2 (b)), results in the $[redacted] amount noted above.

- A $[redacted] transfer of costs from the Distribution PGVA to the 2012/13 Supplemental Gas PGVA was completed in June 2013 as a result of the annual UFG true-up, which served to increase the net Supplemental Gas PGVA balance recoverable from customers (line 7 of Schedule 3.1.2 (b)). The actual UFG percentage for the period from June 2012 through May 2013 was 0.53%, as compared to the originally forecast UFG of 0.90%.
- $[redacted] owing to Centra relates to the timing and implementation of Supplemental Gas base rates approved in Centra's 2013/14 GRA. Had these higher Supplemental Gas base rates been implemented at the outset of the 2012/13 Gas Year on November 1, 2012, base rates would have been sufficient to collect this amount.

- Carrying costs incurred during the period of November 1, 2012 through October 31, 2014 account for a remaining $[redacted] amount recoverable from customers.

The table that follows provides a summary of the makeup of the 2012/13 Supplemental Gas PGVA residual balance of $3.2 million owing to Centra as identified on line 17 of Schedule 3.1.2 (b).

Figure 3.11

2012/13 Supplemental Gas PGVA	
Variance Explanation	Owing to Centra / (Owing to Customers) in $ Millions
Greater than Forecast Purchase Volumes Due to Colder Weather	[redacted]
Average Unit Cost of Purchases Lower than Forecast	
UFG True-up	
Timing of 2012/13 Revised Base Rate Implementation	
Carrying Costs	
Total	$3.2

Schedule 3.4.1 (a) sets out the monthly detail for the 2013/14 Supplemental Gas PGVA. The cost inflows and outflows are based on actual results from November 1, 2013 to October 31, 2014, which results in a $41.8 million balance owing to Centra as at October 31, 2014. This balance is mainly attributable to significantly higher than forecast costs for

Supplemental Gas purchases during the months of January, February and March 2014, which were the result of a combination of extremely cold weather conditions, declining North American storage inventories and extraordinarily high TCPL bid floors for discretionary services on the Mainline, which drove commodity prices at downstream hubs interconnected to the Mainline to unprecedented levels.

[redacted]

TCPL's exercise of its unlimited discretion to set bid floors for short-term services on the Mainline such as STFT and IT, resulted in IT bid floors as high as 55 times the approved daily FT equivalent tolls during the 2013/14 winter. These IT bid floors contributed to high commodity prices at Mainline hubs such as Emerson, as well as other hubs in the region interconnected to the Mainline including in Michigan and Chicago, which all represent hubs from which Centra sources its Supplemental Gas supplies.

Schedule 3.4.1 (b) shows a comparison of actual and approved 2013/14 Supplemental Gas PGVA inflows and outflows. The following provides a discussion of the major contributors to the residual balance:

- Greater than forecast average unit costs for Supplemental Gas purchases, almost exclusively during the three months of January through March 2014, account for a $[redacted] balance owing to Centra. The higher average prices for Centra's Supplemental Gas purchases during this period were the result of the extremely cold weather and high market demand, rapidly declining continental storage inventories, combined with effects of TCPL's exercise of unlimited pricing discretion on commodity market prices, as described above. During the January through March 2014 period, Centra purchased approximately [redacted] GJ and [redacted] GJ of Supplemental Gas supplies respectively to serve its Firm and Interruptible customers' needs (not including Alternate Supply Service for

Interruptible customers). The average unit cost of these supplies was $[redacted]/GJ. By comparison, the Weighted Average Cost of Gas ("WACOG") embedded in Centra's approved Firm and Interruptible Supplemental Gas base rates during this period was $[redacted]/GJ and $[redacted]/GJ respectively.

- An offsetting component of $[redacted] owing to customers is the result of the necessary rounding of customer billing percentages to the whole percentage point, relative to actual underlying Primary/Supplemental Gas purchase splits.

- A $[redacted] component owing to Centra is the result of higher than forecast Supplemental Gas purchases made during September and October 2014 (line 3 of Schedule 3.4.1 (a)). Actual Supplemental Gas purchases (excluding Alternate Supply Service) during these two months totaled approximately [redacted] GJ, as compared to the weather normalized forecast of [redacted] GJ. These incremental volumes were required in order to maintain deliverability to Firm customers while ensuring the re-fill of Centra's storage inventory in advance of the 2014/15 winter.

- A $[redacted] (i.e., refundable to customers, line 8 of Schedule 3.4.1 (b)) transfer of Supplemental Gas costs to the Distribution PGVA was completed in June 2014 as part of the annual UFG true-up process. The actual UFG percentage was 1.0% for the period from June 2013 through May 2014, as compared to the original forecast of 0.9%.

- Carrying costs incurred during the period of November 1, 2013 through October 31, 2014 account for the remaining variance component of approximately $[redacted] recoverable from customers.

The table on the next page shows a summary recap of the various contributors to the $41.8 million 2013/14 Supplemental Gas PGVA residual balance owing to Centra (line 18 of Schedule 3.4.1 (b)), including the directional contribution of each to the final actual balance.

Figure 3.12

2013/14 Supplemental Gas PGVA	
Variance Explanation	Owing to Centra / (Owing to Customers) in $ Millions
Average Unit Cost of Purchases Higher than Forecast	[redacted]
Billing Percentage Rounding	
Greater than Forecast Purchase Volumes Due to Colder than Normal Weather	
UFG True-up	
Carrying Costs	
Total	**$41.8**

Schedule 3.7.1 (a) sets out the monthly detail for the 2014/15 Supplemental Gas PGVA. The cost inflows and outflows are based on actual results from November 1, 2014 to February 28, 2015 and an outlook for the remainder of the 2014/15 Gas Year based on an April 2, 2015 futures market price strip. The inclusion of carrying costs through to the end of the 2014/15 Gas Year results in a forecast $1.5 million balance owing to Centra as at October 31, 2015.

Schedule 3.7.1 (b) shows a comparison of outlook and approved 2014/15 Supplemental Gas PGVA inflows and outflows. The major contributors to the residual balance are as follows:

- Greater than forecast average unit costs for Supplemental Gas purchases over the course of the 2014/15 winter period account for a $[redacted] balance owing to Centra. During the November 1, 2014 through March 31, 2015 period, with March based on outlook figures, Centra purchased approximately [redacted] GJ and [redacted] GJ of Supplemental Gas supplies respectively to serve its Firm and Interruptible customers' needs (not including Alternate Supply Service for Interruptible customers). The average unit cost of these supplies was $[redacted]/GJ. By comparison, the Weighted Average Cost of Gas ("WACOG") embedded in Centra's currently approved Firm and Interruptible Supplemental Gas base rates during this period was $[redacted]/GJ and $[redacted]/GJ respectively.

- An additional $[redacted] owing to Centra is the result of the necessary rounding of customer billing percentages to the whole percentage point, relative to actual underlying Primary/Supplemental Gas purchase splits.

- Carrying costs incurred during the period of November 1, 2014 through October 31, 2015 account for the remaining variance component of approximately $[redacted] recoverable from customers.

The table below shows a summary recap of the various contributors to the $1.5 million 2014/15 Supplemental Gas PGVA residual balance owing to Centra (line 19 of Schedule 3.7.1 (b)), including the directional contribution of each to the final actual balance.

Figure 3.13

2014/15 Supplemental Gas PGVA	
Variance Explanation	Owing to Centra / (Owing to Customers) in $ Millions
Average Unit Cost of Purchases Higher than Forecast	[redacted]
Billing Percentage Rounding	
Carrying Costs	
Total	**$1.5**

3.4.3 2012/13, 2013/14 & 2014/15 Transportation PGVAs

The Transportation PGVA includes the costs associated with the transportation of supplies on various [redacted] and the costs of [redacted] storage capacity. While most of these costs are fixed charges independent of the volume transported, it also includes certain variable transportation costs for each pipeline, along with Centra's inventoried variable costs associated with transporting gas to storage, as well as the imputed transportation costs associated with Primary Gas Delivered Service and Supplemental Gas Peaking Delivered Service. Capacity Management results, which are provided in Appendices 7 and 8 of this Tab, are initially accumulated separately from the Transportation PGVAs, consistent with past practice, and then subsequently transferred with applicable carrying costs into the respective Transportation PGVA's at the conclusion of each gas year.

Schedule 3.1.3 (a) shows the monthly detail for the 2012/13 Transportation PGVA based on actual results from November 1, 2012 to October 31, 2013. After the inclusion of carrying costs through to the end of the 2013/14 Gas Year, the result is a $4.5 million balance owing to customers as at October 31, 2014.

Schedule 3.1.3 (b) shows a comparison of actual and approved 2012/13 Transportation PGVA inflows and outflows. The major contributors to the residual balance were as follows:

- Actual transportation cost inflows were $[redacted] less than the approved forecast, where $[redacted] is attributable to lower TCPL Mainline tolls as established through the RH-003-2011 Decision by the NEB as implemented on July 1, 2013 and the remaining $[redacted] balance pertains to transportation portfolio management activities undertaken by Centra.
- [redacted]

- 2012/13 Capacity Management revenues were $3.3 million lower than the approved amount of $6.3 million embedded in approved transportation base rates for the period (line 21, Schedule 3.1.3 (b)).

- Transportation WACOG outflows were $[redacted] higher than forecast as a result of lower 2012/13 Transportation base rates being implemented on August 1, 2013 as opposed to at the outset of the 2012/13 Gas Year on November 1, 2012.

- The remaining $[redacted] of the $[redacted] of higher than forecast Transportation WACOG outflows (line 26, Schedule 3.1.3 (b)) pertains to colder than normal weather experienced during the 2012/13 Gas Year and the corresponding increase to throughput volumes. Measured on an EHDD basis, the 2012/13 Gas Year was [redacted]% colder than normal.

- A remaining amount of approximately $[redacted] owing to customers is attributable to a combination of carrying costs of $[redacted] (line 28, Schedule 3.1.3 (b)) and $[redacted] resulting from the rounding in the billed rates relative to the underlying forecast gas costs (line 30, "Approved" column, Schedule 3.1.3 (b)).

The following table provides a summary recap of the component variances contributing to the 2012/13 Transportation PGVA residual balance of $4.5 million refundable to customers (line 30 of Schedule 3.1.3 (b)), along with the directional contribution of each to the final actual balance.

Figure 3.14

2012/13 Transportation PGVA	
Variance Explanation	Owing to Centra / (Owing to Customers) in $ Millions
Transportation Costs Lower than Approved due to July 1, 2013 TCPL Mainline Toll Decrease and Centra's Portfolio Management Activities	[redacted]
Capacity Management Revenues Lower than Approved	$3.3
Timing of 2012/13 Revised Base Rate Implementation	[redacted]
WACOG Outflows Higher than Forecast due to Colder than Normal Weather	
Carrying Costs and Rate Design Rounding	
Total	**($4.5)**

Schedule 3.4.2 (a) depicts monthly detail for the 2013/14 Transportation PGVA. Actual results from November 1, 2013 through to October 31, 2014 generate a residual balance of $5.1 million owing to Centra as at October 31, 2014 after the inclusion of carrying costs.

Schedule 3.4.2 (b) shows a comparison of actual and approved 2013/14 Transportation PGVA inflows and outflows. The principal causes of the residual balance are as follows:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- $[redacted] of higher than forecast variable transportation cost inflows resulted from Imputed Transportation Costs on Supplemental Gas Peaking Delivered Service supplies (line 14, Schedule 3.4.2 (b)) purchased largely during extremely cold weather conditions in order to conserve storage inventories and reliability for Firm customers through to the end of the 2013/14 winter.

- Supplemental Gas compressor fuel costs were $[redacted] greater than approved (line 15, Schedule 3.4.2 (b)) as a result of the colder than normal weather experienced during the 2013/14 Gas Year and higher than forecast Supplemental Gas purchase volumes, combined with the high commodity prices experienced during the January through March 2014 period at downstream hubs interconnected with the Mainline.

- Capacity Management revenues were $[redacted] lower than the $[redacted] amount embedded in currently approved transportation base rates (line 21, Schedule 3.4.2 (b)).

- A $[redacted] contribution owing to customers is due to WACOG outflows from the Transportation PGVA that were [redacted]% greater than those that would have been experienced under normal weather conditions as a result of higher throughput due to the previously discussed colder than normal weather during the 2013/14 Gas Year (line 26, Schedule 3.4.2 (b)).

- A remaining amount of approximately $[redacted] owing to customers is attributable to carrying costs (line 28, Schedule 3.4.2 (b)) and the natural rounding in the design of billed rates relative to the underlying forecast gas costs used in their design (line 30, "Approved" column, Schedule 3.4.2 (b)).

The table shown below provides a summary recap of the various 2013/14 Transportation PGVA variance components discussed above and the directional contribution of each to the final actual balance of $[redacted] owing to Centra as identified on line 30 of Schedule 3.4.2 (b).

Figure 3.15

2013/14 Transportation PGVA	
Variance Explanation	Owing to Centra / (Owing to Customers) in $ Millions
[redacted]	
Capacity Management Revenues Lower than Approved	$1.1
[redacted]	
Total	$5.1

Schedule 3.7.2 (a) shows monthly detail for the 2014/15 Transportation PGVA. Actual results from November 1, 2014 through to February 28, 2015 and an outlook for the remainder of the 2014/15 Gas Year based on an April 2, 2015 market price strip generate a forecast residual balance of $11.2 million owing to Centra as at October 31, 2015 including carrying costs.

Schedule 3.7.2 (b) shows a comparison of actual and approved 2014/15 Transportation PGVA inflows and outflows. The key contributors to the residual balance are as follows:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- Supplemental Gas compressor fuel costs are forecast to be $[redacted] greater than approved (line 18, Schedule 3.7.2 (b)) as a result of higher than normal utilization of Supplemental Gas supplies in response to colder than normal weather during the 2014/15 winter combined with Centra's protection of its storage inventories.

- Capacity Management revenues are currently forecast to be $[redacted] less than the $[redacted] amount embedded in currently approved Transportation base rates (line 24, Schedule 3.7.2 (b)).

- A $[redacted] contribution refundable to customers is forecast as a result of WACOG outflows from the Transportation PGVA that through February 2015 were [redacted]% greater than those that would have been experienced under normal weather conditions (line 30, Schedule 3.7.2 (b)).

- A remaining amount of approximately $[redacted] owing to customers is attributable to carrying costs (line 32, Schedule 3.7.2 (b)) and the natural rounding in the design of billed rates relative to the underlying forecast gas costs used in their design (line 34, "Approved" column, Schedule 3.7.2 (b)).

The following table provides a summary recap of the various 2014/15 Transportation PGVA variance components discussed above and the directional contribution of each to the final actual balance of $11.2 million owing to Centra, which is shown on line 34 of Schedule 3.7.2 (b).

Figure 3.16

2014/15 Transportation PGVA	
Variance Explanation	Owing to Centra / (Owing to Customers) in $ Millions
[redacted]	
Capacity Management Revenues Lower than Approved	$1.7
[redacted]	
Total	$11.2

3.4.4 2012/13, 2013/14 & 2014/15 Distribution PGVAs

The Distribution PGVA captures the cost of Unaccounted for Gas (UFG) on Centra's distribution system. UFG volume losses are allocated between Primary Gas and Supplemental Gas and are accounted for monthly on the basis of the monthly average purchase cost of Primary and Supplemental supply delivered to Manitoba. The Distribution PGVA also includes charges on the Minell pipeline as an inflow to this account.

Schedule 3.1.4 (a) details the 2012/13 Distribution PGVA inflows and outflows by month. The inflows and outflows shown are based on actual results from November 1, 2012 to October 31, 2013. After the inclusion of carrying costs, a $1.6 million balance is owing to customers as at October 31, 2014.

Schedule 3.1.4 (b) shows a comparison of actual and approved 2012/13 Distribution PGVA inflows and outflows. The major variances contributing to the residual balance are as follows:

- A $0.9 million amount refundable to customers pertains to the annual UFG true-up booked in June 2013 (line 4, Schedule 3.1.4 (b)). The actual UFG percentage of 0.5% for the period from June 2012 through May 2013 was less than the forecast of 0.9%.

- A variance component of $0.8 million owing to customers is largely the result of colder than normal weather and associated higher than forecast throughput and WACOG outflows (line 9, Schedule 3.1.4 (b)).

- A remaining offsetting amount of approximately $0.1 million recoverable from customers is attributable to a combination of the natural rounding in the design of billed rates relative to the underlying forecast gas costs used in their design (line 13, "Approved column", Schedule 3.1.4 (b)) and slightly higher than forecast UFG costs transferred into the Distribution PGVA from the Primary and Supplemental Gas PGVA's (line 3, Schedule 3.1.4 (b)).

The summary table on the following page shows each of the various 2012/13 Distribution PGVA variance components and their directional contribution to the final actual balance of $1.6 million owing to customers, as shown on line 14 of Schedule 3.1.4 (b).

Figure 3.17

2012/13 Distribution PGVA	
Variance Explanation	Owing to Centra / (Owing to Customers) in $ Millions
UFG True-up	($0.9)
Higher than Forecast WACOG Outflows due to Cold Weather and Higher Volumes	($0.8)
Rate Design Rounding and Higher Transferred-In Primary & Supplemental UFG Costs	$0.1
Total	($1.6)

Schedule 3.4.3 (a) provides monthly detail for the 2013/14 Distribution PGVA, based on actual results from November 1, 2013 to October 31, 2014. This account contains a $1.8 million residual balance owing to Centra as at October 31, 2014 including carrying costs.

Schedule 3.4.3 (b) compares actual and approved 2013/14 Distribution PGVA inflows and outflows. The major contributors to the residual balance are as follows:

- Significantly higher 2013/14 natural gas commodity market prices compared to the WACOG embedded in currently approved distribution base rates contributed an amount owing to Centra from customers of $1.6 million as a result of higher than forecast UFG cost inflows (line 3, Schedule 3.4.3 (b)).

- A $0.4 million component owing to Centra (line 4, Schedule 3.4.3 (b)) pertains to the annual UFG true-up booked in June 2014. The actual UFG percentage of 1.0% for the period from June 1, 2013 through May 31, 2014 was greater than the forecast of 0.9%.

- An offsetting $0.3 million variance, representing an amount owing back to customers, relates to above normal WACOG outflows due to the colder than normal weather experienced during the 2013/14 Gas Year and higher throughput volumes (line 8, Schedule 3.4.3 (b)).

- A remaining amount of approximately $0.1 million owing to Centra is attributable to a combination of the natural rounding in the design of billed rates relative to the underlying forecast gas costs used in their design (line 13, "Approved" column, Schedule 3.4.3 (b)) and to carrying costs (line 11, Schedule 3.4.3 (b)).

A summary table is provided on the next page that shows each 2013/14 Distribution PGVA variance component and its directional contribution to the $1.8 million final actual balance owing to Centra (line 13 of Schedule 3.4.3 (b)).

Figure 3.18

2013/14 Distribution PGVA	
Variance Explanation	Owing to Centra / (Owing to Customers) in $ Millions
Higher than Forecast Unit Costs on UFG Inflows	$1.6
UFG True-up	$0.4
Higher than Forecast WACOG Outflows due to Cold Weather and Higher Volumes	($0.3)
Rate Design Rounding and Carrying Costs	$0.1
Total	$1.8

Schedule 3.7.3 (a) provides monthly detail for the 2014/15 Distribution PGVA, based on actual results from November 1, 2014 to February 28, 2015 and an outlook for the remainder of the 2014/15 Gas Year through October 31, 2015. This account is currently forecast to contain a $0.3 million residual balance owing to Centra as at October 31, 2015 including carrying costs.

Schedule 3.7.3 (b) provides a comparison of outlook and approved 2014/15 Distribution PGVA inflows and outflows, with the major contributors to the residual balance as follows:

- 2014/15 natural gas commodity market prices are forecast to average marginally higher than the WACOG embedded in currently approved distribution base rates, which is therefore projected to result in a variance component owing to Centra of $0.2 million as a result of higher than forecast UFG cost inflows (line 3, Schedule 3.7.3 (b)).

- A remaining amount of approximately $0.1 million owing to Centra is attributable to the inherent rounding in the design of billed rates relative to the underlying forecast gas costs used in their design (line 14, "Approved" column, Schedule 3.7.3 (b)) and to carrying costs (line 12, Schedule 3.7.3 (b)).

The following summary table shows each 2014/15 Distribution PGVA variance component and its directional contribution to the $0.3 million forecast net balance owing to Centra (line 14 of Schedule 3.7.3 (b)).

Figure 3.19

2014/15 Distribution PGVA	
Variance Explanation	Owing to Centra / (Owing to Customers) in $ Millions
Higher than Forecast Unit Costs on UFG Inflows	$0.2
Rate Design Rounding and Carrying Costs	$0.1
Total	$0.3

3.4.5 2012/13, 2013/14 & 2014/15 Heating Value Margin Deferral Accounts

Centra's approved base rates are calculated based on an embedded gas heating value of 37.8 GJ/103m3. When actual heating values are less than 37.8 GJ/103m3, customers consume greater volumes of natural gas than they otherwise would have in order to achieve the same level of energy. As customers' consumption is metered on the basis of volume rather than energy, Centra's gross margin is positively impacted as a result. In cases where actual heating values are greater than the 37.8 GJ/103m3 embedded in rates, the opposite is true. As a result, Centra sets aside these positive and negative gross margin impacts in the Heating Value Margin Deferral Account for refunding to, or recovery from, customers in future periods.

Schedule 3.2.0 shows monthly inflows and outflows for the 2012/13 Heating Value Margin Deferral Account based on actual results from November 1, 2012 to October 31, 2013. After the inclusion of carrying costs, the result is a $0.5 million balance owing to customers as at October 31, 2014 (line 24). Heating values ranged from 37.51 GJ/103m3 to 37.69 GJ/103m3 during the 2012/13 Gas Year as compared to the standard of 37.8 GJ/103m3 embedded in Centra's rates.

Monthly detail for the 2013/14 Heating Value Margin Deferral Account is provided in Schedule 3.5.0. These figures are based on actual results from November 1, 2013 to October 31, 2014. Heating values during the period ranged from 37.61 GJ/103m3 to 38.42 GJ/103m3 as compared to Centra's standard of 37.8 GJ/103m3, resulting in a $0.2 million balance owing to customers, including carrying costs, as at October 31, 2014 (line 11).

Schedule 3.8.0 shows monthly inflows and outflows for the 2014/15 Heating Value Margin Deferral Account based on actual results from November 1, 2014 to February 28, 2015. Outlook results are not provided as Centra is unable to determine gas heating value in advance of actual measurement. After the inclusion of carrying costs, the forecast result is a $0.6 million balance owing to Centra as at October 31, 2015 (line 11). Throughout the period of November 2014 to February 2015 gas heating values ranged from 37.96 GJ/103m3 to 38.46 GJ/103m3 and averaged approximately 38.2 GJ/103m3, which is higher than the standard of 37.8 GJ/103m3 embedded in Centra's rates.

3.5 July 31, 2013 Prior-Period Gas Deferrals Account

In accordance with Order 89/13, rate riders were implemented on August 1, 2013 to dispose of a net amount of approximately $14,000 owing to Centra associated with non-Primary Gas cost deferral balances accumulated in prior periods. Order 85/14 was subsequently issued approving the removal of these rate riders on July 31, 2014 at the conclusion of the 12-month amortization period. Significantly colder than normal weather experienced during the 2013/14 winter and spring of 2014 and resulting higher than forecast rate rider amortizations resulted in a residual balance of approximately $0.2 million owing back to customers on October 31, 2014 after the inclusion of carrying costs. Monthly amortization detail for this account is provided in Schedule 3.9.0.

3.6 SUMMARY OF ALL NON-PRIMARY GAS DEFERRAL ACCOUNT BALANCES TO OCTOBER 31, 2015

The October 31, 2015 Prior-Period Gas Cost Deferrals Account is comprised of all residual non-Primary Gas cost deferral account balances pertaining to both the 2012/13 and 2013/14 Gas Years, the residual balance in the July 31, 2013 Prior-Period Gas Cost Deferrals Account, along with the currently outlook residual balances for each of the 2014/15 non-Primary Gas cost deferral accounts.

Order 123/14 approved on an interim basis the recovery of, over a two year period commencing November 1, 2014, 50% of the forecast net residual balance of $46.7 million owing to Centra in the 2012/13 and 2013/14 Supplemental Gas PGVAs, along with the remaining residual 2010/11 and 2011/12 Supplemental Gas portion remaining in the July 31, 2013 Prior Period Gas Cost Deferrals Account. Order 123/14 also granted interim approval to refund 100% of the forecast net balance of $1.0 million owing to customers in the remaining 2012/13 and 2013/14 non-Supplemental prior-period gas cost deferral accounts, as well as the other non-Supplemental Gas components of the remaining July 31, 2013 Prior Period Gas Cost Deferrals Account residual balance, over a one year timeframe commencing November 1, 2014. As such, Centra transferred the final actual October 31, 2014 residual balances in these various accounts into two separate Prior Period Non-Primary Gas Cost Deferral Accounts (i.e., Supplemental and non-Supplemental) in order to separately track the disposition of these balances in rates.

Schedule 3.10.0 details the various components making up each the respective October 31, 2014 Supplemental and Non-Supplemental Prior Period Gas Cost Deferral Account Balances. This schedule also provides an analysis of the reasons for the differences between each of these amounts as reflected in Centra's interim forecast (contained in Centra's Interim Application for Non-Primary Gas Rate Riders Effective November 1, 2014, filed on July 31, 2014), which included actual results to April 30, 2014 and outlook results for the period of May 1, 2014 through October 31, 2014, compared to the actual final balances as at October 31, 2014.

A final net amount of $46.1 million recoverable from customers (line 21, Schedule

3.10.0) was transferred to the October 31, 2014 Prior-Period Supplemental Gas Cost Deferral Account. This was approximately $0.5 million lesser of an amount owing to Centra than originally forecast in Centra's Interim Application (Schedule 3.10.0, line 21).

In addition, a final actual net balance of $1.3 million owing to customers (line 22, Schedule 3.10.0) associated with all other non-Supplemental prior period gas cost deferral balances was closed out to the October 31, 2014 Non-Supplemental Gas Prior Period Gas Cost Deferrals Account. This balance was an approximately $0.3 million greater amount refundable to customers than the forecast reflected in Centra's Interim Application (Schedule 3.10.0, line 22).

Order 12/15 subsequently modified the 24-month recovery period over which the 50% of the forecast net residual balance of $46.7 million owing to Centra in the October 31, 2014 Prior Period Supplemental Gas Cost Deferral Account was being recovered and shortened the remaining recovery period in order to achieve full recovery of the 50% over a 12-month period by October 31, 2015 by implementing modified rate riders effective February 1, 2015. The 12-month disposition of the forecast amount of $1.3 Million refundable to customers in the October 31, 2014 Prior Period Non-Supplemental Gas Cost Deferral Account was not changed in Order 12/15.

Schedule 3.11.0 provides monthly amortization detail for each of the aforementioned October 31, 2014 Prior Period Gas Cost Deferral Accounts. Incorporating actual results for the November 1, 2014 through February 28, 2015 period, combined with outlook amortizations for the period from March 1, 2015 through October 31, 2015, results in an October 31, 2015 forecast residual balance of $22.2 million owing to Centra in the Supplemental Prior Period Gas Cost Deferral Account (including carrying costs), and $0.4 million owing to customers in the Non-Supplemental Account (including carrying costs). These balances are shown on Schedule 3.11.0, lines 8 and 18 respectively.

In addition to disposition of the October 31, 2015 balances remaining in the October 31, 2014 Supplemental and non-Supplemental Prior Period Gas Cost Deferral Accounts via rate riders over a 12-month period commencing November 1, 2015 and ending October 31, 2016, Centra is also seeking disposition of the October 31, 2015 residual balances in its 2014/15 Gas Year non-Primary Gas cost deferral accounts in rates over the same 12-

month period. Therefore, Schedule 3.11.0 also brings forward the currently outlook October 31, 2015 balances in each of its 2014/15 non-Primary Gas cost deferral accounts for recovery in rates over a 12-month period commencing on November 1, 2015. These outlook 2014/15 residual non-Primary Gas cost deferral account balances are based upon actual results for the November 1, 2014 through February 28, 2015 period and outlook results for the remainder of the 2014/15 Gas Year to October 31, 2015, based on an April 2, 2015 futures market price strip. A total of $13.5 million owing to Centra is currently forecast to accumulate in its 2014/15 non-Primary Gas cost deferral accounts (sum of lines 28 through 31, Schedule 3.11.0).

In summary, Centra is seeking approval to implement rate riders to recover from customers over a 12-month period commencing November 1, 2015 and concluding on October 31, 2016, a net October 31, 2015 Prior Period Non-Primary Gas Cost Deferral Balance of $35.4 million owing to Centra (Schedule 3.11.0, line 33). Centra intends to update these amounts prior to the commencement of the oral hearing to review this Application. The allocation of the $35.4 million balance owing to Centra to the various customer classes and the calculation of rate riders to recover this balance in rates, as well as the resulting rate impacts by customer class, is provided in the Cost Allocation & Rate Design material in Tab 5 and the Rate Schedules and Customer Impacts shown in Tab 6 of this Application.

3.7 2015/16 GAS YEAR GAS COST FORECAST

This section provides a discussion and estimate of gas costs for the forecast period of November 1, 2015 to October 31, 2016. Centra is requesting approval of new Supplemental Gas, Transportation, and Distribution base rates effective November 1, 2015 based on the gas cost information contained in this section of the Application. Centra's forecast of its total non-Primary Gas costs for the 2015/16 Gas Year totals $84.9 million as detailed on Schedule 3.12.4.

3.7.1 Natural Gas Market Analysis

Notwithstanding the short-lived 2014 winter natural gas market price spike, both spot market and long term futures market prices generally have trended to the lower end of the price range experienced since 2000. The current five-year forward average AECO futures price of $3.15/GJ is now only 2% above the 15-year low of the five-year forward average futures price at AECO of $3.08/GJ reached in April 2012.

Technological innovation in the natural gas industry continues to drive down the cost of production from unconventional sources. Techniques such as hydraulic fracturing and multiple directional drilling have occupied most of the mainstream media's coverage of the industry of late. However, other lesser known technologies have also helped to increase supplies while driving down production costs. Some notable examples of the advanced technology now employed in the production of natural gas include:

- 4-dimensional seismic imaging: Along the four dimensions of height, length, width & time, combined with the use of virtual reality imaging facilities.

- Super-computers: In 2013, a major integrated producer opened the world's most powerful commercial super-computing facility, which enables significant improvements in high resolution imaging and modeling of geologic formations.

- Down-hole fiber-optics: Which have enabled the accelerated advancement in the understanding of hydrocarbon bearing-formations and continuous refinements in production techniques.

- Drill bit-embedded geo-magnetic sensors: Which enable gas rigs to guide drill bits within a path as narrow as a foot or less down more than two-miles vertically and then horizontally another two miles over a twelve square mile area from a single drill pad.

- Pad drilling: Which enable the drilling of as many as 150 individual wells from a single six acre drill site.

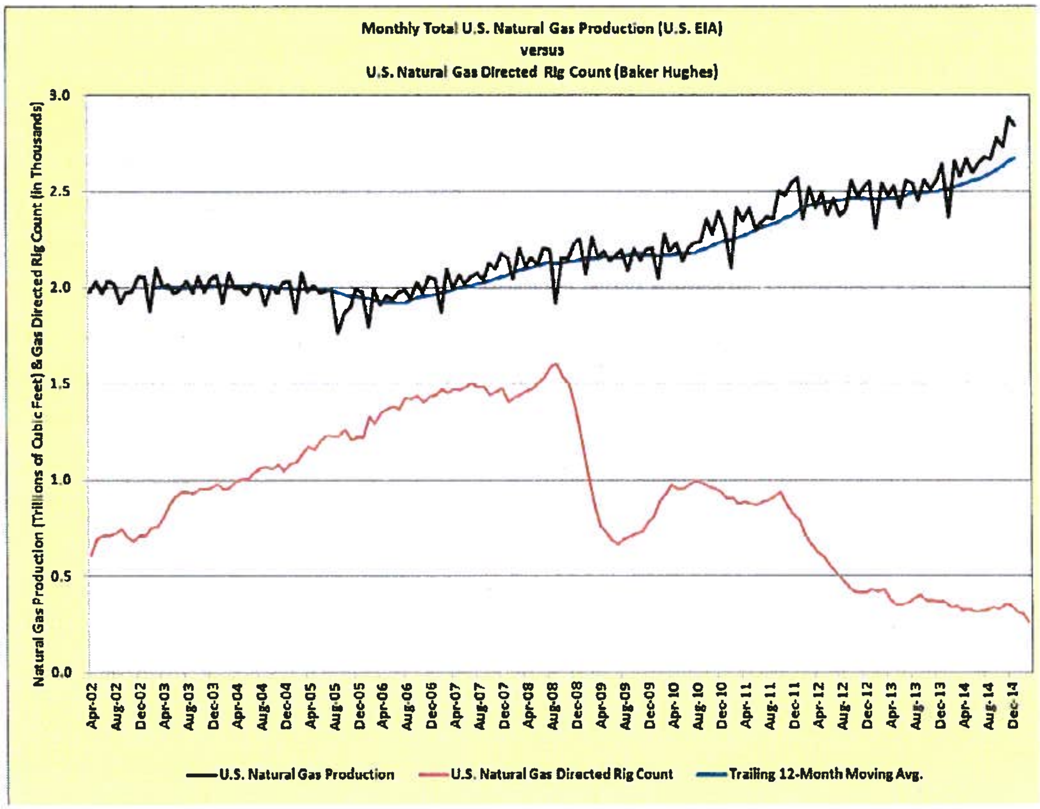
The single most influential advancement that has made the production of natural gas from shale and other tight geologic formations economically feasible has been the combination of one very old drilling technology with another relatively new one:

- Hydraulic fracturing: Widely used commercially since the late 1950s, hydraulic fracturing typically employs a combination of water and a "proppant" such as sand, which typically make up 99.5% of the fracturing fluid by volume, to fracture gas-bearing sedimentary rock formations at pressures as high as 15,000 psi, in order to allow the trapped gas to flow to the surface.

- Directional drilling: By which drillers turn steel drill strings from a vertical direction to the horizontal in order to pierce laterals typically two miles long through tight, gas-bearing rock. As a result, the producing cross-section of a typical unconventional horizontal gas well is now typically orders of magnitude greater than the single 7-inch hole drilled through a reservoir cap rock that had historically been the norm with conventional vertical gas wells.

As a result of the application of these various innovations, the time required to drill a typical natural gas well in North America has fallen by two-thirds since 2007. In addition, well development costs in some basins have fallen by 90% over the past seven years. At the same time, initial well production rates have grown as much as six-fold. The cumulative impact of applying these advanced exploration and production techniques is illustrated in the following chart, which shows total monthly U.S. natural gas production versus the monthly natural gas-directed rig count. Since September 2008, when the U.S. gas rig count reached a high of over 1,600, it has since fallen by almost 85% while, over the same period, monthly natural gas production has grown by nearly 50%.

Figure 3.20



Innovation in natural gas production is expected to continue for the foreseeable future. For example, the following advanced techniques are currently being field tested and could become commonplace in the coming years:

- Liquefied natural gas and propane as a hydraulic fracturing fluid: The use of liquefied natural gas and natural gas liquids such as propane, sourced from nearby producing wells, could dramatically reduce water hauling and post-fracking treatment costs for natural gas producers.

- Robotic drilling rigs: Producers are currently field-testing robotic drilling rigs, fleets of which are to be controlled from centralized "mission control" centres.

Despite the shorter-term market upheavals such as the pricing events during the 2013/14 winter, the industry continues to innovate towards growing gas production, with an expected continuation of the trend of lower prices since the last continent-wide peak in the summer of 2008.

Centra's forecast of its total annual purchased gas costs for the 2015/16 Gas Year, which is discussed in detail in the sections that follow, is a total of $212.8 million as identified on Schedule 3.12.4. While this total is an increase from Centra's total annual purchased gas costs of $160 million during the 2011/12 Gas Year, when market prices reached decade-plus lows, combined with significantly warmer than normal weather and reduced natural gas purchase requirements, it remains less than half of the all time high of $504 million reached in 2000/01. After adjusting for increases in the consumer price index over this sixteen-year period, Centra's forecast purchased gas costs are forecast to be nearly 70% lower in 2015/16 than in 2000/01. A comparison of Centra's annual purchased gas costs over the 2000/01 through 2015/16 forecast period (both in absolute and inflation-adjusted terms) is provided on page 4 of this Tab.

3.7.2 Natural Gas Customer and Volume Forecast

Consumption volumes and customer numbers from November 1, 2015 to October 31, 2016 are based on Centra's most recent normal weather customer and volume forecast as provided in Tab 4. The gas cost estimate considers forecast purchase requirements based on Centra's projection of Sales Service (system supply and marketer supply under WTS) and Transportation Service volumes. Total purchase requirements were developed from the estimate of normal sales volumes considering UFG amounts equal to 0.9% of total system receipts. This UFG factor represents long-term historical data and is reflective of typical UFG losses.

3.7.3 Primary Gas Direct to Load

Western Canadian supply costs for Primary Gas for the forecast period from November 1, 2015 to October 31, 2016 are based on the terms of Centra's current Primary Gas supply contract, which came into effect on November 1, 2014 and runs for a two year term until expiry on October 31, 2016. [redacted], and which are discussed earlier in this tab in section 3.1.1 Gas Supplies – Primary Gas. The gas cost forecast in this Application incorporates futures market prices as of the April 2, 2015 market close.

Monthly average Primary Gas supply prices delivered directly to Centra's load are forecast to range between $2.82/GJ and $3.21/GJ over the forecast period as provided on Schedule 3.12.1, line 54.

3.7.4 Supplemental Gas Direct to Load

Supplemental Gas supplies are priced based upon Emerson futures market prices as per an April 2, 2015 strip date. Supplemental Gas Direct to Load supply prices in the 2015/16 Gas Year are forecast to range between $3.44 CAD/GJ and $4.29 CAD/GJ as provided on Schedule 3.12.1 line 58.

3.7.5 Uncontracted Supplies

Under normal weather conditions, approximately [redacted] GJ of uncontracted supply is forecast to be required to meet the Interruptible Class load during the 2015/16 Gas Year. This supply requirement is excess to that available to serve the system load by means of firm contracted Primary Gas direct to the load, Supplemental Gas direct to the load, and storage withdrawal capabilities. These volumes represent the amount of Alternate Supply Service or curtailment that is forecast, on a normal weather basis, for Interruptible Class customers. As such, these volumes have been excluded from the 2015/16 gas cost forecast. In the event that Interruptible Class customers require these uncontracted supplies, they would be offered Alternate Supply Service on a best efforts basis. Uncontracted supplies are purchased on a day-to-day basis as required, as a delivered service, with those costs recovered directly from those Interruptible Class customers that elect Alternate Supply Service.

3.7.6 Transportation and Storage Costs

Mainline tolls embedded in this gas cost forecast for the entire forecast period reflect the tolls contained in TCPL's March 2015 compliance filing with the NEB, which at the time of this writing, were anticipated to be approved for implementation by the NEB effective May 1, 2015. These tolls represent an approximately 8% annual increase in TCPL Mainline toll costs relative to the tolls that were in place up to and including December, 31, 2014, which is less than the 12% Mainline toll increase implemented on January 1, 2015 flowing from the NEB's RH-001-2014 Hearing Order, prior to TCPL's aforementioned compliance filing.

In addition, NEB Order MH-001-2013, which flows from the NEB's LMCI process and was issued on May 29, 2014, now requires Centra and all other Mainline shippers to pay abandonment surcharges beginning January 1, 2015 as discussed above in respect of the 2014/15 Transportation PGVA as well as in section 3.3, TCPL and Related Matters. These pipeline abandonment surcharges are identified separately on schedule 3.12.1 for each of Centra's individual TCPL Mainline transportation paths, as well as other pipeline systems to which these charges apply and on which Centra is a shipper.

[redacted]

3.7.7 Storage Withdrawals

Centra's storage forecast is based on the projected balances in each of the gas storage accounts at the end of the 2014/15 winter withdrawal season incorporating actual results to February 28, 2015, plus the forecast cost of injections during the summer 2015 re-fill season. The forecast average inventory cost for each component as at October 31, 2015 is as follows:

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

The cost of the forecast storage withdrawals for the 2015/16 winter season is determined using these average inventory costs.

[redacted]

3.7.9 Capacity Management Forecast

The five-year average of Centra's actual Capacity Management revenues has been updated to $5.3 million from the previously approved $6.3 million. The $5.3 million forecast amount is based on the most recent 60-month rolling average of Centra's actual Capacity Management results through to February 28, 2015 (line 32 of Schedule 3.12.3).

3.7.10 Resulting Forecast Gas Costs for 2015/16 Gas Year

The total cost of gas forecast for the gas year from November 1, 2015 to October 31, 2016 is $212.8 million. The details in support of this forecast are contained within Schedules 3.12.1 through 3.12.4.Schedule 3.12.1 summarizes the fixed and variable transportation unit costs, commodity unit supply prices, [redacted], fuel ratios, UFG and heating values. Schedule 3.12.2 summarizes contract demand levels and forecast purchase requirements to the Manitoba load. Schedules 3.12.3 (a) and (b) summarize total gas costs grouped into fixed transportation costs, variable transportation costs, supply costs and other costs.

Schedule 3.12.4 summarizes the overall difference between forecast 2015/16 gas costs and forecast recoveries at the existing base rates that were implemented on August 1, 2013.

Figure 3.22 below compares requested non-Primary Gas costs for the 2015/16 Gas Year with the revenues that would be generated by existing approved non-Primary Gas base rates. Column 1 indicates the revenues that would be generated by existing approved base rates. Column 2 summarizes the non-Primary Gas costs forecast for the 2015/16 Gas Year. Column 3 shows the revenue deficiency between forecast 2015/16 non-Primary

Gas costs and revenues at existing base rates. Centra is seeking increases in its non-Primary Gas base rates in the amount of $11.5 million effective November 1, 2015.

Figure 3.22

Non-Primary Gas Costs ($000s)

	Revenue at Existing Base Rates	Forecast Non-Primary Gas Costs for 2015/16	Revenue Deficiency
Supplemental Gas	$22,922	$23,257	$335
Transportation	$48,096	$59,230	$11,134
Distribution	$2,315	$2,375	$61
Total Non-Primary Gas Costs	**$73,333**	**$84,862**	**$11,530**

The allocation of forecast non-Primary gas costs to the various customer classes and the calculation of base rates to recover these forecast amounts, as well as the resulting rate impacts by customer class, are provided in the Cost Allocation & Rate Design material in Tab 5 and the Rate Schedules and Customer Impacts in Tab 6 of this Application.