CENTRA GAS MANITOBA INC.
2019/20 GENERAL RATE APPLICATION

GAS SUPPLY & COSTS

INDEX

8.0 Overview 1
8.1 Centra's Gas Supply Portfolio 4
8.2 Capacity Management Program 16
8.3 NGTL / TCPL Mainline and Related Matters 19
8.4 Gas Costs and Gas Cost Deferrals Summary 22
8.5 2014/15 Gas Costs 23
8.6 2015/16 Gas Costs 27
8.7 2016/17 Gas Costs 33
8.8 2017/18 Gas Costs 39
8.9 2018/19 Gas Year Gas Cost Forecast 45
8.10 Forecast Gas Costs for the 2018/19 Gas Year 51

Schedules

See the attached Schedule Index

Appendices

8.1 Design Firm Peak Day (Winter)
8.2 Design Firm Peak Day (Summer)
8.3 TCPL map
8.4 Summer Operations
8.5 Winter Operations
8.6 2014/15 Gas Year Capacity Management Reporting
8.7 2015/16 Gas Year Capacity Management Reporting
8.8 2016/17 Gas Year Capacity Management Reporting

CENTRA GAS MANITOBA INC.
2019/20 GENERAL RATE APPLICATION

GAS SUPPLY & COSTS

8.0 OVERVIEW

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.

Centra's total realized gas costs in the 2014/15, 2015/16 and 2016/17 Gas Years (i.e., the annual period used by the natural gas industry that runs from November 1 to October 31 each year), as well as the gas cost outlook for the 2017/18 Gas Year are summarized in Figure 8.1 below.

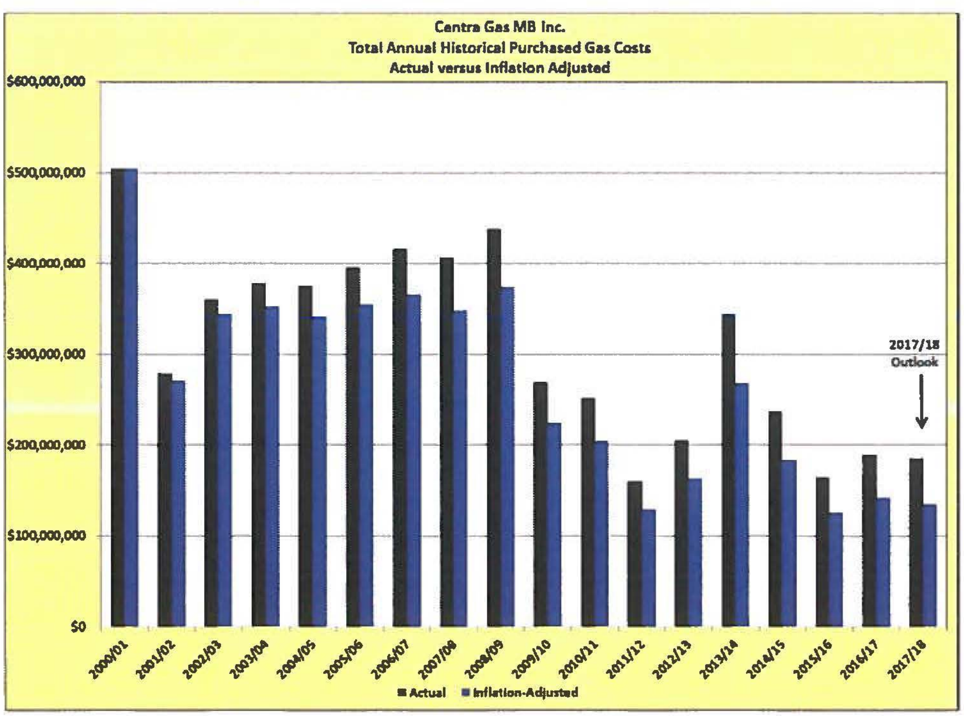
Figure 8.1:

Centra's Portfolio Costs by Gas Year ($ millions CAD)	2014/15	2015/16	2016/17	2017/18
Primary Gas	[redacted]			
Supplemental Gas				
Supply Costs	171.0	103.2	125.7	121.1
TCPL & other firm transport	[redacted]			
U.S. assets				
Fixed Transportation & Storage Costs	62.6	60.2	61.9	59.4
Variable Transportation & Storage Costs	5.1	6.6	7.5	8.3
Other Costs/(Revenue)	-2.7	-4.7	-5.3	-3.8
TOTAL	236.0	165.3	189.8	185.0
* Totals may not add due to rounding.				
Actual weather colder/ (warmer) than normal	[redacted]			

1a, 1e

As illustrated by Figure 8.2 below, Centra's annual gas costs since 2000/01 have ranged from $160 million to $504 million. The period since 2013/14 has been characterized by low and stable natural gas (commodity) prices, thus, the most recent four Gas Years have been at or near the low end of the aforementioned range. A more complete natural gas market analysis is contained in Section 8.9.1.

Figure 8.2:



In this Application, Centra is seeking final approval of actual gas costs of $236.0 million incurred in the 2014/15 Gas Year, $165.3 million incurred in 2015/16, and $189.8 million in 2016/17. In addition, Centra is providing a gas cost outlook for 2017/18 totaling $185.0 million based on actual results through April 2018 and forecast figures for the months of May to October 2018. Centra will update 2017/18 gas costs with final actual results as part of the pre-hearing update to be filed prior to the commencement of the oral hearing related to this Application and seek final approval of Centra's 2017/18 gas costs through this process.

The cumulative net total of all prior period non-Primary Gas PGVA balances for the four years noted above are currently forecast to total a refundable amount of $6.4 million as at July 31, 2019 including associated carrying costs. Centra is seeking approval to implement new non-Primary Gas rate riders effective August 1, 2019 to dispose of these prior period PGVA balances in customers' rates over the 12-month period ending July 31, 2020.

Centra's gas cost forecast for the 2018/19 Gas Year totals $177.3 million, including forecast non-Primary Gas costs of $79.3 million. This forecast is proposed to form the basis of new non-Primary Gas base rates for which Centra is also seeking approval to implement effective August 1, 2019. A discussion of the actual, outlook and forecast gas costs, as well as the timing of the recovery of the resulting prior period gas cost deferral balances follows in Sections 8.4.0 through 8.10.0 of Tab 8 of this Application.

This Tab provides a description of:

- Centra's gas supply portfolio;
- The changes to Centra's gas supply portfolio since the 2015/16 Cost of Gas ("COG") Application;
- Developments in matters related to the pipelines on which Centra transports natural gas and their impacts on Centra;
- The actual gas costs incurred and resulting gas cost deferral balances for the 2014/15, 2015/16, 2016/17, and 2017/18 Gas Years for which Centra seeks final approval as part of this Application; and

- The forecast of gas costs for the 2018/19 Gas Year for which Centra seeks interim approval as part of this Application.

8.1 CENTRA'S GAS SUPPLY PORTFOLIO

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

8.1.1 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 (direct to load or Primary Gas from Storage), by marketers through the Western Transportation Service ("WTS"), or by contractual arrangements referred to as Primary Gas Delivered Services ("PGDS").

Centra Supply

Centra purchased 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") from November 1, 2016 to October 31, 2018. This contract was executed following a comprehensive Request for Proposal ("RFP") process conducted in 2016, and was filed in confidence with the PUB in October 2016. Prior to November 1, 2016, Centra purchased its Primary Gas from ConocoPhillips under a similar two-year supply contract for the period November 1, 2014 to October 31, 2016. Under these contracts, the [redacted] of Primary Gas supply are [redacted] 1a 1a

Natural gas purchased as [redacted] 1a. Natural gas purchased as [redacted] 1a provides for the purchase of natural gas on a [redacted] 1a. This allows Centra to [redacted], primarily due to [redacted] 1a.

Earlier in 2018, Centra concluded its Western Canadian gas supply RFP process for the period November 1, 2018 through October 31, 2020. ConocoPhillips was the successful proponent. The contract is [redacted], other than the [redacted]. In the 2014-16 and the 2016-18 contracts, 1a the [redacted] based on the [redacted]. In the 1a 2018-20 contract, this component is [redacted] 1a.

There are a number of factors affecting market conditions on the NOVA Gas Transmission Ltd. ("NGTL") system. The sources of new supply in the Western Canadian Sedimentary Basin ("WCSB") are predominantly further afield, in north-western Alberta and north-eastern B.C., and there is a lag in the availability of NGTL capacity to connect theses sources of supply with export points on the NGTL system such as Empress. The result is an increase in the market value of existing NGTL transportation to Empress, further exacerbated by periodic system restrictions associated with NGTL's maintenance and construction activities to increase capacity on its system.

Centra is contracted for [redacted] of FT-D capacity on the NGTL system to Empress, 1a which allows Centra to acquire a portion of its Primary Gas supply at the AECO hub. As an NGTL export shipper with associated natural gas liquids ("NGL") extraction rights, Centra executes NGL extraction agreements with Empress straddle plant operators. The revenue from these agreements serves to reduce Centra's Primary Gas costs at Empress.

Marketer Supply (WTS)

Manitoba natural gas customers may elect to purchase their Primary Gas directly from an independent gas marketer, rather than Centra. Centra facilitates the transportation of these gas supplies by way of the Western Transportation Service. 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 the 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 for the three Gas Years beginning with 2015/16:

Figure 8.3:

Customers and Primary Gas MDQ for WTS		
	Number of Customers	**Maximum Daily Quantity (GJ/day)**
November 1, 2017	9,000	10,355
November 1, 2016	11,900	11,225
November 1, 2015	15,000	13,164

Primary Gas Delivered Services

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 PGDS, whereby a counterparty delivers gas directly to the Manitoba market. [redacted]. 1a, 1c

Supplemental Gas

Supplemental Gas is natural gas sourced on a daily, monthly or seasonal basis to serve the Manitoba market's peak day and maximum seasonal requirements, and includes U.S. Supplies, Supplemental Gas from storage and Supplemental Gas Delivered Services ("SGDS") in which supplies are delivered directly to Manitoba by counterparties for specified terms depending on forecast and actual loads. Supplemental Gas is used to serve the load when Centra is [redacted] 1c 1c 1c

During the winter months, Centra may purchase Supplemental Gas in the [redacted] 1c 1c 1c

During the summer months, Emerson supply may be purchased to maintain storage injections or for transport on the TCPL Mainline to the Manitoba market. Centra may also purchase [redacted]. 1c

Alternate Supply Service

Physical curtailment and/or the provision of Alternate Supply Service to Interruptible customers may be required to protect storage inventory for firm customers, or whenever demand is forecast to exceed Centra's firm deliverability. If a delivered service to the Manitoba market is available, Interruptible customers are offered Alternate Supply Service at pass-through pricing (i.e., prices that reflect the cost of the delivered service). These customers retain the right to decline the offer of Alternate Supply Service from Centra, cease to consume natural gas, and utilize their standby fuel source. Prices and quantities are arranged in a very short timeframe, rarely more than a day in advance and sometimes intra-day.

Gas Management Agreement with SaskEnergy

Centra acquired the assets of the Swan Valley Gas Corporation in 2014. The Swan Valley service area is neither interconnected with the TCPL Mainline nor Centra's existing distribution system in Manitoba, thus the natural gas to serve 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 Centra's total market requirement, serving approximately 300 customers.

Gas Supplies Required for Centra's Design Firm Peak Day

Centra's design firm peak day is the forecast volume of natural gas required to serve all Firm Sales customers, including WTS customers, on the coldest winter day experienced. The design firm peak days for the past five Gas Years are provided in Figure 8.4 below.

Figure 8.4:

1c

Forecast Design Firm Peak Day	
Gas Year	**GJ/day**
2013/14	[redacted]
2014/15	[redacted]
2015/16	[redacted]
2016/17	[redacted]
2017/18	[redacted]

Centra's forecast design firm peak day for the 2018/19 Gas Year is [redacted]. 1c

Appendix 8.1 provides the sources of supply available to meet Centra's forecast winter design firm peak day and Appendix 8.2 provides the same information for Centra's forecast summer design firm peak day. This information is provided for the most recent five Gas Years, as well as for the 2018/19 winter (2019 summer information is not yet available).

8.1.2 Transportation and Storage Arrangements

Centra has transportation and storage arrangements in place with a number of pipelines and service providers.

NGTL (Transportation)

Primary Gas supply purchased at the AECO hub is transported by way of NGTL Firm Transportation-Delivery ("FT-D") capacity to Empress.

TCPL Mainline (Transportation)

Primary Gas supplies purchased or received at Empress, either as Centra supply or Western Transportation Service supply, are transported from Western Canada to the TCPL Mainline's Southern Saskatchewan Delivery Area ("SSDA") and Manitoba Delivery Area ("MDA") by way of Firm Transportation ("FT") or [redacted] 1a 1a 1a 1a. The majority of Centra's customers receive natural gas service through meter stations on the TCPL Mainline in the Centram MDA (the contractual delivery point for the MDA), while a relatively small number of customers in the Parkland region of the Province are supplied from a meter station in the Centram SSDA that is located in Saskatchewan and is part of the TCPL Mainline's SSDA. Appendix 8.3 provides a map of these sections of the TCPL Mainline system.

Centra also contracts for FT on the Mainline from Emerson to the Centram MDA [redacted] 1c. This transportation path contributes to meeting Centra's deliverability requirements.

Centra also contracts for Storage Transportation Service ("STS") on the Mainline between the MDA/SSDA and Emerson. This service facilitates the refill of storage in summer months and is part of the full transportation path from storage to the Manitoba market in winter months.

<u>CTHI (Transportation)</u>

To provide service to a customer in the R.M. of Piney, Centra holds FT from Empress to the Centrat MDA, the contractual delivery point on the TCPL Mainline where it interconnects with the Centra Transmission Holdings Inc. ("CTHI") system near Spruce Siding, Manitoba. Centra holds corresponding firm annual capacity on CTHI to serve this customer.

<u>ANR and GLGT (Transportation and Storage)</u>

Centra contracts for ANR storage capacity in Michigan, which requires related transportation on the ANR and GLGT pipelines. Storage and the related transportation contracts are used to improve Centra's transportation load factor from Western Canada. Storage allows Centra to reduce its unutilized demand charges ("UDC") related to use of transportation capacity at a low sales load factor. Centra's forecast transportation load factor from Western Canada for the 2018/19 Gas Year is approximately [redacted]% compared 1d to a forecast sales load factor of approximately [redacted]%.

Centra originally contracted for total storage capacity of 15.5 PJ effective April 1, 2013, with 215,614 GJ/day (net of pipeline compressor fuel) of storage deliverability and related pipeline capacity on GLGT and ANR. The total annual fixed cost for these arrangements was $14.0 million USD for a seven year term ending March 31, 2020.

In correspondence dated June 2, 2016, Centra advised the PUB of its decision to increase its ANR seasonal storage capacity by 1 PJ (1 million GJ) effective June 1, 2016. Consequently, the annual fixed cost of Centra's ANR and GLGT arrangements has increased from $14.0 million USD to $14.2 million USD. [redacted] 1c 1c The capacity expires on March 31, 2020, coincident with the expiry of the rest of Centra's U.S. transportation and storage arrangements with ANR and GLGT.

Centra now holds 9.1 PJ of seasonal storage capacity with ANR, which limits injections to summer and withdrawals to winter, and allows storage gas to be cycled up to 1.0 times annually. Centra also holds 7.4 PJ of annual storage capacity as originally contracted, which allows both injections and withdrawals in any season, and allows storage gas to be cycled up to 1.42 times annually as per ANR's Federal Energy Regulatory Commission ("FERC") approved tariff.

8.1.3 Portfolio Operations

Centra's Portfolio operations are described by season in the following subsections. Appendix 8.4 provides a map that outlines summer operations under Centra's Portfolio. Appendix 8.5 illustrates how Centra operates its Portfolio during the winter season.

<u>**Summer Operations (April 1 through October 31)**</u>

Centra purchases Western Canadian gas supplies under its Primary Gas supply contract and transports these and marketer supplies on a combination of NGTL Firm Transportation-Delivery, TCPL Mainline Firm Transportation [redacted] 1a
to meet the firm Manitoba market requirement. Primary Gas Delivered Service arrangements and Emerson supply [redacted] to satisfy daily 1c
market demand.

Any Manitoba load requirement in excess of Centra's [redacted] 1c
Supplemental Gas Delivered Services. Also, Interruptible customers are offered Alternate Supply Service (or are physically curtailed as required) whenever forecast demand exceeds Centra's ability to provide and deliver supply under its firm contractual arrangements. Once the firm Manitoba market requirement has been met, excess transportation capacity can be used to refill storage in Michigan, serve the Interruptible load, or be released to third parties where feasible and economic.

The storage refill is accomplished utilizing the following transportation contracts:

1. NGTL FT-D from AECO to Empress (up to 54,000 GJ/day of the available FT-D);
2. Mainline FT from Empress to the MDA (up to 54,000 GJ/day of the available FT);
3. Mainline Storage Transportation Service from the MDA to Emerson, Manitoba (up to 54,000 GJ/day);
4. GLGT FT from Emerson to the interconnect with ANR at Crystal Falls[1], Michigan (up to 53,280 GJ/day);
5. ANR Firm Transportation Service ("FTS") from Crystal Falls to the ANR Pipeline storage facilities in Michigan (up to 52,964 GJ/day); and
6. ANR FTS from Joliet Hub to the ANR Pipeline storage facility in Michigan (up to 7,385 GJ/day of Chicago supply).

<u>Winter Operations (November 1 through March 31)</u>

The Manitoba market requirement is [redacted] natural gas purchased under Centra's Primary Gas supply contract and Primary Gas received from marketers (for Western Transportation Service customers) and transported to the load using a combination of NGTL FT-D, TCPL Mainline FT [redacted]. PGDS arrangements and/or U.S. Supplies [redacted] to satisfy daily market demand. [redacted], Centra transports gas withdrawn from storage on ANR, GLGT and the TCPL Mainline to supply the Manitoba market during winter months. 1c 1a, 1c 1c

At the beginning of winter, under the assumption of a normal weather year, Primary Gas, U.S. Supplies, Storage, and SGDS are used to meet both Firm and Interruptible requirements. As the winter progresses, Centra monitors the extent to which weather has varied from normal and the resulting storage inventory levels. If storage withdrawals are greater than planned, Centra may offer Alternate Supply Service to Interruptible customers (or physically curtail them as required) to conserve storage gas for the firm market. Alternate Supply Service or physical curtailment of Interruptible

[1] This point is known as Crystal Falls on the ANR system and Fortune Lake on the GLGT system. Centra will use "Crystal Falls" to refer to the point in either case.

customers may also be required to ensure that the firm load is met during colder than normal weather on any particular day.

To meet the market requirement, storage volumes and/or U.S. Supplies are transported to Manitoba using the following transportation contracts:

1. ANR FTS from the ANR storage facility to the GLGT interconnect at Deward (up to 215,614 GJ/day);
2. GLGT FT from Deward/Farwell to Emerson (up to 236,716 GJ/day);
3. Mainline STS from Emerson to the MDA and SSDA (up to 215,614 GJ/day); and
4. Mainline FT from Emerson to the MDA (up to 69,750 GJ/day).

Also included in Centra's current Portfolio for use during the winter months is 42,202 GJ/day of ANR FTS capacity from the Joliet Hub to ANR storage, which provides Centra with optionality in managing its storage levels by providing access to Chicago supply.

8.1.4 Changes to Portfolio since the 2015/16 COG

Changes in Centra's Portfolio since the 2015/16 COG (filed in May 2015) are outlined below.

TCPL Mainline

During the 2015/16 Gas Year, Centra held TCPL Mainline Firm Transportation from Empress to the Manitoba Delivery Area through February at 140,000 GJ/day[2] [redacted]. 1a 1c

For the 2016/17 winter, Centra's TCPL Mainline Empress to MDA FT levels were 140,000 GJ/day. [redacted] 1a

[2] During the March through October 2016 timeframe, Centra mitigated its fixed transportation costs by not renewing 15,000 GJ/day of expiring Mainline FT.

[redacted] Early in 2017, Centra was contacted by a Transportation Service 1c ("T-Service") customer which sought to transfer from T-Service to Centra's firm sales service during the 2016/17 Gas Year. Centra was able to accommodate the request, including taking assignment of the customer's Mainline FT contract of 1,000 GJ/day from Empress to the Centram MDA. As a result, Centra's Empress to MDA FT during the 2016/17 Gas Year increased by 1,000 GJ/day effective April 1, 2017 (to the March 31, 2019 expiry date of the assigned contract).

For the 2017/18 Gas Year, Centra's TCPL Mainline Empress to MDA FT remained at 141,000 GJ/day. [redacted] 1a 1c

Looking forward to the 2018/19 Gas Year, Centra has contracted for an incremental 20,000 GJ/day of TCPL Mainline FT (Empress to MDA) effective November 1, 2018, thereby increasing its contract demand to 161,000 GJ/day through the 2018/19 winter. Effective April 1, 2019, this quantity will decrease to 160,000 GJ/day. [redacted] 1c 1a, 1c 1c

NGTL

In December of 2017, NGTL issued an open season for a total of 1,365,000 GJ/day of firm capacity to the Empress/McNeill export (border) points in Alberta to increase market access for WCSB gas. To increase its ability to source gas directly at the AECO hub in the near future, Centra participated in this open season and was awarded its requested incremental capacity of [redacted] for a term of [redacted]. 1a

The capacity is expected to be available in [redacted], subject to NGTL obtaining National Energy Board ("NEB") regulatory approval and completion of construction. 1a

The open season included 260,000 GJ/day of existing capacity available October 2018, and a combined 1,105,000 GJ/day of expansion capacity available November 2020 and April 2021. Aggregate open season bids exceeded available capacity and successful bids were for exceptionally long terms, including an unprecedented average term of 107 years for existing capacity and an average term of 28.6 years for expansion capacity.

This new future capacity will allow Centra to mitigate long-term supply and price risk by increasing the volume of gas it can buy at AECO, one of the most liquid natural gas hubs in North America.

<u>**U.S. Transportation & Storage**</u>

In Order 112/12, the PUB approved the fixed costs of Centra's 2013-2020 portfolio of natural gas storage and related transportation contracts with ANR and GLGT. Directive 2 of Order 112/12 required Centra to report if there were any changes to the fixed costs of this portfolio. As mentioned above in Section 8.1.2, the only change to Centra's ANR or GLGT fixed costs was the incremental 1 PJ of storage for which Centra contracted in June 2016 at an annual average cost of $142,000 USD over the four year period ending March 31, 2020. The resulting costs by Gas Year are shown in Figure 8.5 below:

Figure 8.5: Incremental Cost of Additional 1 PJ of Storage (USD)

2015/16	2016/17	2017/18	2018/19	2019/20
61,766	148,239	148,239	148,239	61,766

With regard to Centra's variable costs, a settlement between ANR and its shippers related to a FERC rate case filed by ANR was reached in 2016. ANR's tariff reservation and commodity transportation rates increased by 34.8% effective August 1, 2016, resulting in an annual commodity charge increase for Centra of approximately $60,000 USD. The reservation rates of Centra's discounted ANR contracts were not subject to the rate increase. As part of this settlement, Centra also received a one-time lump sum payment of approximately $700,000 USD due to excess revenue collected by ANR for post-retirement benefits other than pensions.

A settlement between GLGT and its shippers related to a FERC rate case filed by GLGT was reached in 2017, resulting in GLGT's tariff reservation and utilization rates decreasing by 27% effective October 1, 2017. The impact on Centra was an annual utilization charge reduction of approximately $64,000 USD. The reservation rates of Centra's discounted GLGT contracts were not subject to the rate decrease given the extent to which they are already discounted.

Tab 9 provides information on Centra's proposed transportation and storage portfolio effective April 1, 2020.

8.2 CAPACITY MANAGEMENT PROGRAM

8.2.1 Capacity Management ("CM") Program Overview

The objective of Centra's CM Program is to optimize use of the Portfolio so as to minimize its related costs, only after Centra's first and foremost obligation to meet the Manitoba market requirement for natural gas is fulfilled. 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 counterparty interest in the transaction to determine the potential value associated with any particular arrangement. 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.

To generate CM revenue there must be a market participant willing to pay a price that covers any incremental costs involved in the transaction and provides some recovery of the underlying cost of the asset while also satisfying Centra's credit requirements.

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:

1. An outright capacity release (i.e., the capacity is unencumbered);
2. A capacity release with an associated delivery obligation, commonly referred to as an asset management arrangement ("AMA"); or
3. A diversion, whereby Centra agrees to transport another party's gas to a predetermined point for a fee. Revenue in excess of the incremental cost associated with the diversion is recorded 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 point. The value of an exchange 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 volume that would otherwise be transported by Centra on a particular day. In some circumstances, the volume delivered to the counterparty may be less than the volume received by Centra on a particular day, requiring subsequent repayment of the imbalance at some point in the future. These deferred exchanges may result in incremental CM revenue and/or allow Centra to reduce costs.

8.2.2 CM Program Results

Due to ever changing circumstances such as fluctuations in weather, pricing and basis differentials, it is difficult to forecast the revenue that may be earned through CM transactions. As a result, the five-year rolling average of actual CM revenue has been used and has served as an appropriate benchmark to estimate the CM credit to be embedded prospectively in customers' transportation rates each year in advance of the realization of these revenues. In any given year, there will inevitably be a difference between the CM revenue being refunded to customers in rates based on the rolling five-year average and the actual CM revenue earned by Centra. This difference accumulates in Centra's Transportation PGVA, with any over- or under-refunded amount brought forward for review, approval and disposition in rates in a future period. This ensures that over time, customers are refunded, dollar for dollar, the exact amount of CM revenue earned by Centra.

The information that follows on the CM revenue earned in the 2014/15, 2015/16, and 2016/17 Gas Years compares actual results to the benchmark of the previous 5-year rolling average of actual CM revenue. This information differs from any discussion of CM revenue in the sections of the Application related to Transportation PGVAs which compares actual CM results to the $5.1 million approved forecast of CM revenue embedded in currently approved rates.

During the 2014/15 Gas Year, Centra earned $3.1 million of CM revenue (excluding carrying costs). This amount was $2.1 million less than the forecast of $5.2 million, which was calculated using the five-year rolling average of actual results for the period from November 1, 2009 through October 31, 2014.

During the 2015/16 Gas Year, Centra earned $5.1 million in CM revenue (excluding carrying costs), which is $0.5 million greater than the forecast amount of $4.6 million based on the updated five-year rolling average of actual results for the period from November 1, 2010 through October 31, 2015.

During the 2016/17 Gas Year, Centra earned $4.7 million in CM revenue (excluding carrying costs), which is $0.1 million greater than the forecast amount of $4.6 million based on the updated five-year rolling average of actual results for the period from November 1, 2011 through October 31, 2016.

Attached as Appendices 8.6, 8.7 and 8.8 are detailed monthly CM reporting for the 2014/15, 2015/16, and 2016/17 Gas Years. At the time of drafting this Application, the 2017/18 Gas Year was not yet concluded. Centra will provide its detailed monthly CM reporting for the 2017/18 Gas Year as part of the pre-hearing update to be filed prior to the commencement of the oral hearing related to this Application.

8.3 NGTL / TCPL MAINLINE AND RELATED MATTERS

The majority of the natural gas supply used to serve Centra's franchise territory comes from the Western Canadian Sedimentary Basin and is transported by way of the NGTL system and the TCPL Mainline. The NGTL system is an integrated natural gas pipeline system located in Alberta and British Columbia. It gathers and transports natural gas produced in the WCSB for delivery to intra-Alberta and export markets. The TCPL Mainline physically transports all natural gas supplies that are consumed in Centra's service territory[3], thus Centra's gas supply planning and operations are significantly influenced and affected by the current and future business environment of the WCSB, and the pipelines that transport WCSB supply to Centra's market. Centra participates on industry committees that monitor and participate in reviewing tolls, tariff, services, facilities and procedures on NGTL and the TCPL Mainline. A number of settlements have been reached and regulatory proceedings have taken place before the National Energy Board ("NEB") since the 2015/16 COG proceeding before the PUB.

NGTL Revenue Requirement and Tolls

On December 1, 2015, NGTL filed a revenue requirement settlement application for 2016 and 2017 (TG-001-2016). The application was approved by the NEB on April 8, 2016. The term differentiated tolls (excluding abandonment surcharges) that Centra paid during the two-year term of the settlement were:

- 2016 – January 1 to December 31 (Interim & Final) $0.185/GJ/day
- 2017 – January 1 to May 31 (Interim) $0.193/GJ/day
- 2017 – June 1 to December 31 (Final) $0.182/GJ/day

NGTL filed a revenue requirement settlement application on March 23, 2018 for 2018 and 2019 (TG-004-2018). The NEB approved the application on June 19, 2018. The term differentiated tolls (excluding abandonment surcharges) that Centra has paid and is currently paying are:

---

[3] With the exception of the Swan Valley service area which encompasses approximately 300 customers.

- 2018 – January 1 to April 30 (Interim) $0.165/GJ/day
- 2018 – May 1 to December 31 (Final) $0.168/GJ/day

2019 tolls will be set once NGTL's revenue requirement for 2019 is determined.

<u>TCPL Mainline Tolls</u>

On December 12, 2017, TCPL filed a Mainline tolls application with the NEB for the 2018-2020 period (RH-001-2018). In the RH-001-2014 decision, the NEB approved, among other things, tolls for the 2015-2020 period subject to TCPL filing a tolls review application for the 2018–2020 period. TCPL applied to the NEB to set final Mainline tolls for the 2018-2020 period at the same level at which the January 1, 2018 interim tolls were set by the NEB, 2% lower than 2015-2017 tolls for Centra's transportation contracts, as follow:

- Empress to Centram MDA $0.5678/GJ/day
- Empress to Centram SSDA $0.4217/GJ/day
- Emerson to Centram MDA and STS $0.1679/GJ/day

TCPL's application for final Mainline tolls for 2018-2020 in the RH-001-2018 proceeding before the NEB did not incorporate disposition of a $1.142 billion "owing to shippers" deferral account balance as at the end of 2017. The amortization and allocation of this deferral account balance was the fundamental issue in the proceeding. Centra actively opposed TCPL's application and provided an alternative tolling proposal for the NEB's consideration that at least 75% of this deferral account balance be amortized over the 2018-2020 period, and used to deliver a pro-rata toll reduction of 23% for Mainline shippers. The RH-001-2018 proceeding concluded on October 9, 2018 and all parties are awaiting the NEB's decision on the Application.

<u>TCPL Mainline Services</u>

Storage Transportation Service ("STS")

On February 18, 2016 TCPL filed an application for approval of changes to the Canadian Mainline Tariff with respect to STS (RH-001-2016). TCPL sought changes to STS to standardize individually negotiated STS contracts, and apply STS tolls to STS contract quantities in a consistent manner. TCPL proposed to charge 12 months on the Withdrawal Quantity of STS contracts, which would have increased Centra's costs by $11 million annually. Centra opposed the application and actively intervened in the regulatory proceeding before the NEB. In its RH-001-2016 decision, the NEB denied TCPL's application for amendments to STS for the remainder of the fixed toll period (i.e., to the end of 2020), consistent with Centra's opposition and intervention. The NEB indicated that STS could be reviewed during the comprehensive Mainline tolls and tariff proceeding for the post-2020 period.

Long-Term Fixed Price ("LTFP") Services

TCPL is negotiating LTFP offerings from Empress to attract incremental revenue and/or retain existing long-haul transportation contracts by discounting FT capacity for long-term commitments (i.e., 10 years). Each service offering is unique in pricing and attributes and is assessed by the NEB on its own merits. Centra supported TCPL's application for the Herbert LTFP Service (RH-002-2017) and conditionally supported the Dawn LTFP Service (RH-003-2017), subject to in-path diversions to Emerson 2 being allowed as part of Dawn LTFP to better maintain adequate liquidity at Emerson. The NEB approved both the Herbert and Dawn LTFP applications as filed.

Energy East

On October 5, 2017, TCPL announced the termination of Energy East and the related Eastern Mainline Projects. TCPL indicated in a media release that the decision was reached following a "careful review of changed circumstances".

Abandonment Cost Estimates (NGTL and TCPL Mainline)

During the MH-001-2012 proceeding, the NEB determined that abandonment cost estimates ("ACE") should be reviewed at least once every five years to help mitigate the under- or over-collection of funds. On October 29, 2015, the NEB advised that it would commence a review starting in 2016 of the ACEs of all regulated pipeline companies.

As part of the ACE review, both the TCPL Mainline and NGTL filed updated estimates on September 30, 2016. The TCPL Mainline's ACE increased by $525 million from $2.4 billion ($2011) to $2.9 billion ($2016) and NGTL's ACE increased by $613 million from $1.9 billion ($2011) to $2.5 billion ($2016). Both estimates were approved by the NEB on April 18, 2018 and future impacts to the abandonment surcharge of each pipeline are not yet known. The abandonment surcharges paid by Centra for the last three years are outlined in Figure 8.6 below:

Figure 8.6:

Abandonment Surcharges Paid by Centra from 2016 to 2018			
Path ($/GJ/day)	**2016**	**2017**	**2018**
TCPL – Empress to Centram MDA	0.0485	0.0601	0.0569*
TCPL – Empress to Centram SSDA	0.0340	0.0420	0.0398*
TCPL – Emerson 2 to Centram MDA & STS	0.0088	0.0106	0.0100*
NGTL – AECO to Empress Border	0.0104	0.0099	0.0091

*Interim Rates

8.4 GAS COSTS AND GAS COST DEFERRALS SUMMARY

In this Application, Centra is seeking the following approvals:

1. Final approval of actual gas costs of $236.0 million incurred in the 2014/15 Gas Year, $165.3 million incurred in 2015/16, and $189.8 million for 2016/17;
2. Final approval of Centra's 2017/18 gas costs, the current outlook for which is $185.0 million based on actual results through April 2018 and the forecast for the months of May to October 2018 based on May 15, 2018 futures market prices. Centra will provide final actual 2017/18 gas cost results as part of the pre-hearing update to be filed prior to the commencement of the oral hearing related to this Application.
3. The cumulative net total of all prior period non-Primary Gas PGVA balances for the four years noted above are currently forecast to total a refundable amount

of $6.4 million including associated carrying costs to July 31, 2019. Centra is seeking approval to implement new non-Primary Gas rate riders effective August 1, 2019 to dispose of these prior period PGVA balances in customers' rates over the 12-month period ending July 31, 2020.

4. Interim approval of its non-Primary Gas cost forecast for the upcoming 2018/19 Gas Year totaling $79.3 million that will form the basis of new non-Primary Gas base rates for which Centra is also seeking approval to implement effective August 1, 2019. As is the case for its current outlook of 2017/18 gas costs and associated non-Primary Gas PGVA balances, Centra will also provide an update of its 2018/19 gas cost forecast prior to the commencement of the oral hearing to review this Application.

Sections 8.5, 8.6, 8.7 and 8.8 that follow provide the details of all gas costs and PGVA balances for the 48-month period from November 1, 2014 to October 31, 2018. Schedule 8.8.6 summarizes the forecast net accumulation of all prior period non-Primary Gas PGVA balances to July 31, 2019, for which Centra is seeking approval to implement 12-month rate riders effective August 1, 2019. The forecast of Centra's 2018/19 gas costs found in Section 8.9 is based on a May 15, 2018 futures market price strip date for the period from November 2018 to October 2019 and form the basis of the new non-Primary Gas base rates for which Centra is seeking interim approval to implement on August 1, 2019.

8.5 <u>2014/15 GAS COSTS</u>

Schedule 8.5.0 provides the details of Centra's actual 2014/15 gas costs totaling $236.0 million, along with a comparison of those costs to Centra's original forecast of $237.4 million that was approved on an interim basis in Order 108/15 following the hearing to review Centra's 2015/16 COG Application in the fall of 2015. The following sections provide a general overview of the PGVAs relating to this period, along with a description of the treatment of the October 31, 2015 PGVA balances that accumulated in each account.

8.5.1 2014/15 Primary Gas PGVA

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; and
- Compressor fuel on the TCPL system to transport Primary Gas purchases from Alberta to Manitoba.

Primary Gas supplies used to support Unaccounted for Gas ("UFG") requirements are removed from this account and transferred to the Distribution PGVA.

Details pertaining to the Primary Gas PGVA for the period from November 1, 2014 to October 31, 2015 have been provided for information purposes only. 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 is requesting final approval of actual Primary Gas costs of $[redacted] incurred during the period from November 1, 2014 to October 31, 2015 as detailed on line 12 of Schedule 8.5.1. 1a

The Primary Gas PGVA 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 analyses of the Primary Gas PGVAs are provided in the Primary Gas PGVA discussions for each Gas Year in this Application.

8.5.2 2014/15 Supplemental Gas PGVA

The Supplemental Gas PGVA captures the cost of:

- Supplemental Gas purchases (as described on page 7, Tab 8 of the Application);
- Supplemental Gas Delivered Services; and

- Supplemental Gas withdrawn from Storage.

Schedule 8.5.2(a) provides actual results pertaining to the 2014/15 Supplemental Gas PGVA. The final balance totaling $[redacted] was transferred into the October 31, 2015 Prior Period Gas Cost Deferrals Account, which formed the basis of the 12-month rate riders implemented on November 1, 2015 that were approved on an interim basis in Order 108/15 following Centra's 2015/16 COG Application proceeding as discussed in further detail in Section 8.5.6. Schedule 8.5.2(b) provides a comparison of actual 2014/15 Supplemental Gas cost inflows and outflows to the amounts approved on an interim basis in Order 108/15. 1a

8.5.3 2014/15 Transportation PGVA

The Transportation PGVA includes the costs associated with the transportation of supplies on various Canadian and U.S. pipeline systems and the cost of contracted U.S. storage capacity. While most of these costs are fixed charges independent of the volume transported, they also include certain variable transportation costs for each pipeline, along with Centra's inventoried variable costs associated with transporting gas to storage, as well as delivered service imputed transportation costs. CM results, which are discussed in Section 8.2 and detailed in Appendices 8.6, 8.7, and 8.8, are initially accumulated separately from the Transportation PGVAs, consistent with past practice, and then subsequently transferred with applicable carrying costs into the respective Transportation PGVAs at the conclusion of each gas year.

Schedule 8.5.3(a) shows actual inflows and outflows for the 2014/15 Transportation PGVA. After the inclusion of carrying costs through to the end of the 2014/15 Gas Year, a final balance of $14.4 million owing to Centra as at October 31, 2015 was transferred into the October 31, 2015 Prior Period Gas Cost Deferrals Account as discussed further in Section 8.5.6. A comparison of actual to interim approved account inflows and outflows is shown on Schedule 8.5.3(b).

8.5.4 2014/15 Distribution PGVA

The Distribution PGVA captures the cost of UFG on Centra's distribution system. UFG volume losses are allocated between Primary Gas and Supplemental Gas and 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. Minell is a wholly owned subsidiary of Manitoba Hydro and Centra is the sole shipper on the Minell pipeline, which serves approximately 4,500 natural gas customers.

Schedule 8.5.4(a) provides actual 2014/15 Distribution PGVA results. The net final balance in this account was $0.3 million owing to customers. Schedule 8.5.4(b) provides a comparison of actual versus approved amounts. As was the case for both the 2014/15 Supplemental Gas and Transportation PGVAs, this balance was transferred into the October 31, 2015 Prior Period Gas Cost Deferral Account at the conclusion of the Gas Year (see Section 8.5.6).

8.5.5 2014/15 Heating Value Margin Deferral

Centra's approved base rates are calculated based on an embedded gas heating value of [redacted] $GJ/10^3m^3$. When actual heating values are less than [redacted] $GJ/10^3m^3$, customers consume greater volumes of natural gas than they otherwise would have to achieve the same level of energy. The converse is also true. Furthermore, as customers' consumption is metered on the basis of volume rather than energy, Centra's gross margin is positively impacted when actual heating values are less than [redacted] $GJ/10^3m^3$. In cases where actual heating values are greater than the [redacted] $GJ/10^3m^3$ 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. 1d 1d

Schedule 8.5.5 provides actual results for the 2014/15 Heating Value Margin Deferral Account. A final year-end balance of $[redacted] was transferred into the October 31, 2015 Prior Period Gas Cost Deferral Account as discussed in the following Section 8.5.6. 1d

8.5.6 October 31, 2015 Prior Period Gas Cost Deferrals Account

In accordance with Order 108/15, rate riders were implemented on November 1, 2015 to dispose of a net amount of approximately $36.1 million owing to Centra associated with non-Primary Gas PGVA balances accumulated in prior periods up to and including October 31, 2015. At the time of Centra's 2015/16 COG proceeding in September 2015, at which Centra sought approval to dispose of these amounts, the $36.1 million recoverable balance that was approved on an interim basis in Order 108/15 was based on actual results to June 30, 2015 and outlook values for the months of July through October 2015. The final accumulated net value of all prior period gas cost deferral account balances transferred into this account on October 31, 2015 totaled $[redacted], which is detailed on Schedule 8.5.6(a). Schedule 8.5.6(a) also provides explanations of the individual account variances giving rise to the approximately $[redacted] net difference between the interim approved and final amounts. Consistent with the interim approvals provided in Order 108/15, 12-month rate riders were applied to customer billings commencing on November 1, 2015 to dispose of these accumulated deferral balances which remained in place until October 31, 2016, after which they were removed from customers' billed rates. Monthly amortization details for this account are provided in Schedule 8.5.6(b). The residual balance of $[redacted] as at October 31, 2016 (line 19) is a result of the previously discussed opening balance differential of [redacted], combined with lower than forecast rate rider amortizations predominantly as a result of the warmer than normal weather experienced over the course of the 2015/16 Gas Year which contributed the remaining $[redacted]

1e 1e 1e

As Centra is requesting approval to implement new non-Primary Gas rate riders effective August 1, 2019 to dispose of all prior period PGVA balances accumulated through to the conclusion of the 2017/18 Gas Year, carrying costs to July 31, 2019 have been added to this account's October 31, 2016 residual balance (Schedule 8.5.6(b), line 27). Therefore, the July 31, 2019 balance in this account, including the aforementioned carrying costs, is a net balance of $[redacted] (Schedule 8.5.6(b), line 29). 1e

8.6 2015/16 GAS COSTS

Schedule 8.6.0 details actual 2015/16 gas costs totaling $165.3 million, as compared to the forecast of $211.2 million approved on an interim basis in Order 108/15. Centra's annual gas costs for the 2015/16 Gas Year rank as the second lowest since the start of the new millennium. These low gas costs resulted from a combination of low natural gas market prices, combined with the 4th warmest winter in Manitoba in the past 56 years.

8.6.1 2015/16 Primary Gas PGVA

Schedule 8.6.1 sets out the monthly details for the Primary Gas PGVA for the 2015/16 Gas Year. Centra's actual Primary Gas costs for the period totaled $[redacted] (line 12). 1a

8.6.2 2015/16 Supplemental Gas PGVA

Schedule 8.6.2(a) sets out the monthly detail for the 2015/16 Supplemental Gas PGVA. Schedule 8.6.2(b) shows a comparison of actual and approved 2015/16 Supplemental Gas PGVA inflows and outflows. Variance explanations pertaining to the $[redacted] as at October 31, 2016 (Schedule 8.6.2(a), line 19) are as follow: 1e

- The actual average unit cost of Supplemental Gas purchases, excluding Alternate Supply Service, was $[redacted]. This compares to the forecast average unit cost of $[redacted] (line 23 of Schedule 8.6.2(b)). This average Supplemental Gas price differential, multiplied by the [redacted] GJ of Supplemental Gas purchases to serve system supply requirements (line 21 of Schedule 8.6.2(b)), accounts for a $[redacted]. 1a 1d 1a
- An offsetting variance of $0.3 million owing to Centra is the result of the necessary rounding of customers' Supplemental Gas billing percentages to the nearest whole percentage point, relative to the actual underlying Primary/Supplemental Gas purchase splits.
- The remaining variance component of $0.1 million owing to Centra relates to costs previously booked from the Supplemental Gas PGVA to the Distribution PGVA that were transferred back to the Supplemental Gas PGVA in June 2016 as part of the annual UFG true-up process (Schedule 8.6.2(b), line 9). The actual UFG percentage for the period from June 2015 through May 2016 was 0.24%, as compared to the original forecast of 0.9%.

Figure 8.7 below shows a summary recap of the various contributors to the $[redacted] 2015/16 Supplemental Gas PGVA [redacted] as at July 31, 1e

2019 (line 19 of Schedule 8.6.2(b)), which includes the addition of approximately $[redacted] of additional carrying costs for the period from November 1, 2016 through July 31, 2019 (line 17 of Schedule 8.6.2(b)), including the directional contribution of each to the final balance. 1e

Figure 8.7

2015/16 Supplemental Gas PGVA		
Variance Explanation	**Owing to Centra / (Owing to Customers) in $ Millions**	
Average Unit Cost of Purchases [redacted] than Forecast	[redacted]	1a
Billing Percentage Rounding	$0.3	
UFG True-up	$0.1	
Carrying Costs	[redacted]	1e
Total	[redacted]	

8.6.3 2015/16 Transportation PGVA

Schedule 8.6.3(a) shows the monthly detail for the 2015/16 Transportation PGVA. Schedule 8.6.3(b) shows a comparison of actual and approved 2015/16 Transportation PGVA inflows and outflows. The major contributors to the October 31, 2016 residual balance of $4.8 million owing to Centra (line 35 of Schedule 8.6.3(a)) were as follow:

- TCPL Mainline fixed transportation costs were $[redacted] than approved as shown on Schedule 8.6.3(b), line 4, which is comprised of two items: 1e
    - Fixed FT costs were $[redacted] than forecast because Centra was able to forego re-contracting 15,000 GJ/day of TCPL Mainline FT-NR from March 2016 through October 2016. 1e
    - Abandonment surcharge costs were $[redacted] than forecast due to NEB-approved abandonment toll increases implemented on January 1, 2016. 1e

- [redacted] costs (Schedule 8.6.3(b), line 5) were $[redacted] than forecast as a result of Centra having contracted [redacted] than 1a anticipated and [redacted] arrangements.
- Offsetting [redacted] in fixed ANR and GLGT transportation costs of approximately $[redacted] relative to forecast was the result of two factors (Schedule 8.6.3(b), 1e lines 6-7):
  - Canada/U.S. exchange rate variance of $[redacted]. Actual exchange 1e rates during the 2015/16 Gas Year averaged $1.32 CAD/US versus the $1.25 CAD/US embedded in the interim approved transportation base rates for the period.
  - Incremental seasonal storage capacity of 1 PJ was contracted by Centra effective June 1, 2016. This additional capacity [redacted] ANR fixed costs 1e by $[redacted] CAD compared to budget.
- Lower than normal supply requirements during the winter of 2015/16 due to warmer than normal weather reduced variable storage transportation, injection and withdrawal costs by $[redacted] (Schedule 8.6.3 (b), lines 13-16 & 18). 1e
- Imputed transportation costs for delivered service arrangements, which were not budgeted, but resulted in an overall lower cost for these supplies, 1a contributed a variance amount of $[redacted] (i.e., an offset to the total $[redacted] discussed in the first two 1e items above and as shown on lines 4 & 5 of Schedule 8.6.3(b)). These amounts are shown on Schedule 8.6.3(b), lines 17 & 19.
- Miscellaneous transportation costs of $[redacted] were incurred during the 1a 2015/16 Gas Year and relate to [redacted], deferred transportation cost adjustment ("DTCA") costs on ANR, 1c and deferred storage delivery service ("DDS") charges (Schedule 8.6.3(b) line 26).
- Transportation WACOG outflows were $4.9 million lower than forecast as a result of warmer than normal weather experienced during the 2015/16 Gas Year and the corresponding decrease in customer consumption. Measured on an Effective Heating Degree Day ("EHDD") basis, the 2015/16 Gas Year was [redacted] 1d warmer than normal.

Figure 8.8 below provides a summary recap of the component variances contributing to the 2015/16 Transportation PGVA residual balance of $5.1 million owing to Centra as of July 31, 2019 (line 35 of Schedule 8.6.3(b)), an amount that includes an additional $0.3 million of November 1, 2016 through July 31, 2019 carrying costs, along with the directional contribution of each to the final actual balance.

Figure 8.8

2015/16 Transportation PGVA	
Variance Explanation	**Owing to Centra / (Owing to Customers) in $ Millions**
TCPL Mainline FT Cost Reduction	[redacted]
Abandonment Surcharge Increase Effective January 1, 2016	[redacted]
[redacted]	[redacted]
Higher than Forecast CAD/US Exchange Rates	[redacted]
Storage Capacity Increase (effective June 1, 2016)	[redacted]
Lower Than Forecast Variable Storage Transportation, Injection and Withdrawals Costs	[redacted]
Delivered Service Imputed Transportation Costs	[redacted]
[redacted], DTCA & DDS	[redacted]
WACOG Outflows Lower than Forecast due to Warmer than Normal Weather	$4.9
Carrying Costs	$0.3
Total	**$5.1**

1a, 1c, 1e

8.6.4 2015/16 Distribution PGVA

Schedule 8.6.4(a) shows actual 2015/16 Distribution PGVA inflows and outflows by month. A comparison of actual and approved 2015/16 Distribution PGVA inflows and outflows is provided on Schedule 8.6.4(b). The major variances contributing to the residual balance of $1.6 million owing to customers as at October 31, 2016 (Schedule 8.6.4(a), line 12) are as follows:

- Lower than forecast 2015/16 average prices for Centra's Primary and Supplemental Gas purchases contributed an amount owing to customers of $0.7 million as a result of lower than forecast UFG cost inflows to this account (Line 3 of Schedule 8.6.4(b)).
- A $1.1 million amount refundable to customers pertains to the annual UFG true-up booked in June 2016. The actual UFG percentage was 0.24% for the period from June 2015 through May 2016, as compared to the original forecast of 0.9% (Schedule 8.6.4(b), line 4).
- A variance component of $0.2 million owing to Centra is largely the result of warmer than normal weather and associated lower than forecast customer consumption and WACOG outflows (Schedule 8.6.4(b), line 8).

After the addition of $0.1 million of carrying costs for the November 1, 2016 through July 31, 2019, the final balance in this account will be $1.7 million owing to customers as at July 31, 2019 (line 14 of Schedule 8.6.4(b)). Figure 8.9 below provides the various 2015/16 Distribution PGVA variance components discussed above and their directional contribution to the final balance.

Figure 8.9

2015/16 Distribution PGVA	
Variance Explanation	**Owing to Centra / (Owing to Customers) in $ Millions**
Lower than Forecast Unit Costs on UFG Inflows	($0.7)
UFG True-up	($1.1)
Lower than Forecast WACOG Outflows due to Warmer Weather and Lower Volumes	$0.2
Carrying Costs	($0.1)
Total	**($1.7)**

8.6.5 2015/16 Heating Value Margin Deferral Account

Schedule 8.6.5 displays the 2015/16 Heating Value Margin Deferral Account. Actual heating values ranged from 37.78 $GJ/10^3m^3$ to 38.41 $GJ/10^3m^3$ and averaged 38.10 $GJ/10^3m^3$ during the 2015/16 Gas Year as compared to the standard of [redacted] $GJ/10^3m^3$ 1d embedded in Centra's rates. As the actual heating content of the natural gas delivered exceeded that embedded in rates, an amount of $[redacted] to Centra 1e accumulated over the course of the 2015/16 Gas Year. The addition of $[redacted] of carrying costs for the period from November 1, 2016 through July 31, 2019 results in a total deferral balance of $[redacted] as of July 31, 2019 1e (line 16 of Schedule 8.6.5).

8.7 2016/17 GAS COSTS

Schedule 8.7.0 compares actual 2016/17 Gas Year costs totaling $189.8 million to the 2015/16 Gas Year forecast of $211.2 million approved on an interim basis in Order 108/15.

8.7.1 2016/17 Primary Gas PGVA

Schedule 8.7.1 provides details for the Primary Gas PGVA for the 2016/17 Gas Year. Centra's actual Primary Gas costs for the period totaled $[redacted] (line 12). 1a

8.7.2 2016/17 Supplemental Gas PGVA

Monthly detail for the 2016/17 Supplemental Gas PGVA is provided in Schedule 8.7.2(a). Schedule 8.7.2(b) provides a comparison of actual and approved 2016/17 Supplemental Gas PGVA inflows and outflows. As of the end of the 2016/17 Gas Year on October 31, 2017, a refundable balance of $[redacted] had accumulated in this 1a account. The main contributors to this year-end deferral balance are as follow:

- The average unit cost of Supplemental Gas purchases, excluding Alternate Supply Service, was [redacted]. This compares to the forecast average unit cost of 1a [redacted] embedded in customers' base rates during the period, both of which are shown on line 23 of Schedule 8.7.2(b). This average Supplemental Gas price differential, multiplied by the [redacted] GJ of Supplemental Gas purchases to 1d serve system supply requirements (line 21 of Schedule 8.7.2(b)), accounts for a $[redacted]. 1a

- An additional variance component of $0.7 million owing to customers is the result of the necessary rounding of customers' Supplemental Gas billing percentages to the nearest whole percentage point, relative to the actual underlying Primary/Supplemental Gas purchase splits.
- [redacted] amount based on the carrying cost forecast to July 31, 2019, the amount of which is estimated at $[redacted] (line 17 of Schedule 8.7.2(b)). 1e

Figure 8.10 below provides a summary recap of the various contributors to the $[redacted] 2016/17 Supplemental Gas PGVA residual balance [redacted] as at July 31, 2019 (line 19 of Schedule 8.7.2(b)), which includes carrying costs for the period from November 1, 2017 through to July 31, 2019, including the directional contribution of each to the final balance. 1e

Figure 8.10

2016/17 Supplemental Gas PGVA	
Variance Explanation	**Owing to Centra / (Owing to Customers) in $ Millions**
Average Unit Cost of Purchases [redacted] than Forecast	[redacted]
Billing Percentage Rounding	($0.7)
Carrying Costs	[redacted]
Total	[redacted]

1a
1e

8.7.3 2016/17 Transportation PGVA

Monthly 2016/17 Transportation PGVA inflows and outflows are provided on Schedule 8.7.3(a), where a $4.7 million balance owing to Centra (line 36) remained in this account at the conclusion of the 2016/17 Gas Year. Schedule 8.7.3(b) compares actual and approved 2016/17 Transportation PGVA inflows and outflows. The major contributors to the residual balance were as follow:

- TCPL Mainline fixed transportation costs were $[redacted] more than approved
  as shown on line 4 of Schedule 8.7.3(b). Abandonment Surcharges were $[redacted] 1e
  higher than forecast as a result of abandonment surcharge increases that were approved by the NEB and implemented on January 1, 2016 and January 1
  2017 respectively. The remaining $[redacted] fixed cost variance pertains to the 1e
  assignment of 1,000 GJ/day of Empress to MDA annual FT capacity to Centra by a former T-Service customer effective April 1, 2017, as described in Section 8.1.4.
- [redacted] costs (Schedule 8.7.3(b), line 5) were $[redacted] than forecast as a 1a
  result of Centra contracting for [redacted]
  [redacted], as well as [redacted] 1c
  [redacted]. These [redacted] 1a, 1c
  were [redacted] (as discussed below and as indicated on Schedule 8.7.3(b), line 19).
- ANR and GLGT fixed transportation costs increased by approximately $[redacted] 1e
  relative to forecast as the result of two factors (Schedule 8.7.3(b), lines 6-7):
  - Canada/US exchange rates [redacted] costs by $[redacted]. Actual 1e
    exchange rates during the 2016/17 Gas Year averaged $1.31 CAD/US versus the $1.25 CAD/US originally forecast.
  - Incremental seasonal storage capacity of 1 PJ was contracted effective
    June 1, 2016. This [redacted] ANR fixed costs by $[redacted]. 1e
- Total variable storage related transportation, injection and withdrawal costs
  were [redacted] than budget ((Schedule8.7.3 (b) lines 13-16 & 18) 1e
- Delivered service imputed transportation costs, [redacted] 1a
  [redacted], contributed a variance component of $[redacted]
  (Schedule 8.7.3(b), lines 17 & 19). [redacted] 1a
  [redacted] of gas in Manitoba and
  [redacted]. 1c
- TCPL balancing fees were $0.1 million less than forecast (line 24 of Schedule 8.7.3(b)).

- CM revenues were $0.4 million lower than the 5-year average of $5.1 million embedded in customer's rates (line 25 of Schedule 8.7.3(b)).
- Centra received a one-time $0.9 million CAD refund associated with its portion of the excess revenue collected from shippers by ANR for its employees' post-retirement benefits during the preceding years (Schedule 8.7.3(b) line 27), as described in Section 8.1.4.
- Transportation WACOG outflows were $2.7 million lower than forecast (Schedule 8.7.3(b) line 32) as a result of warmer than normal weather experienced during the 2016/17 Gas Year and the corresponding decrease in customer consumption. Measured on an EHDD basis, the 2016/17 Gas Year was [redacted]% warmer than normal. 1d

Figure 8.11 below provides a summary recap of the component variances contributing to the 2016/17 Transportation PGVA residual balance of $4.9 million owing to Centra as at July 31, 2019 (line 36 of Schedule 8.7.3(b)), an amount that includes an additional $0.2 million of November 1, 2017 through July 31, 2019 carrying costs, along with the directional contribution of each to the final balance.

Figure 8.11

2016/17 Transportation PGVA	
Variance Explanation	**Owing to Centra / (Owing to Customers) in $ Millions**
Abandonment Surcharges Higher than Forecast	[redacted]
T-Service Customer Capacity Assignment to Centra	[redacted]
[redacted]	[redacted]
Higher than Forecast CAD/US Exchange Rates	[redacted]
Storage Capacity Increase	[redacted]
Lower Than Forecast Variable Storage, Transportation, Injection and Withdrawal Costs	[redacted]
Delivered Service Imputed Transportation Costs	[redacted]
Balancing Fees Lower than Forecast	($0.1)
CM Revenues Lower Than Trailing 5-Year Average	$0.4
ANR Settlement Refund	($0.9)
WACOG Outflows Lower than Forecast due to Warmer than Normal Weather	$2.7
Carrying costs	$0.2
Total	**$4.9**

1a, 1e

8.7.4 2016/17 Distribution PGVA

Schedule 8.7.4(a) details the monthly 2016/17 Distribution PGVA where the account balance as of October 31, 2017 was $0.9 million refundable to customers (line 12). Schedule 8.7.4(b) presents the actual versus approved 2016/17 Distribution PGVA inflows and outflows. The major variances contributing to this refundable balance are as follow:

- Lower 2016/17 natural gas market prices compared to forecast contributed an amount owing to customers of $0.4 million as a result of lower than forecast UFG cost inflows (Schedule 8.7.4(b), line 3).
- An additional $0.6 million amount refundable to customers pertains to the annual UFG true-up booked in June 2017. The actual UFG percentage was 0.58% for the period from June 2016 through May 2017, as compared to the original forecast of 0.9% (Schedule 8.7.4(b), line 4).
- A variance component of $0.2 million owing to Centra is the result of warmer than normal weather and associated lower than forecast throughput and WACOG outflows (Schedule 8.7.4(b), line 8).
- Carrying costs through July 31, 2019 accumulate to an amount owing to customers of $0.1 million.

Figure 8.12 below provides a summary of the various 2016/17 Distribution PGVA variance components discussed above and their directional contribution to the final balance of $0.9 million owing to customers on July 31, 2019, which is shown on line 14 of Schedule 8.7.4(b).

Figure 8.12

2016/17 Distribution PGVA	
Variance Explanation	**Owing to Centra / (Owing to Customers) in $ Millions**
Lower than Forecast Unit Costs on UFG Inflows	($0.4)
UFG True-up	($0.6)
Lower than Forecast WACOG Outflows due to Warmer Weather and Lower Volumes	$0.2
Carrying Costs	($0.1)
Total	**($0.9)**

8.7.5 2016/17 Heating Value Margin Deferral Account

Schedule 8.7.5 details the monthly activity for the 2016/17 Heating Value Margin Deferral Account. Heating values ranged from 37.90 $GJ/10^3m^3$ to 38.23 $GJ/10^3m^3$ and averaged 38.02 $GJ/10^3m^3$ during the 2016/17 Gas Year as compared to the standard of [redacted] $GJ/10^3m^3$ embedded in Centra's rates. As shown on Schedule 8.7.5, line 16, these 1d higher than forecast heating values results in a $[redacted] 1e from customers on July 31, 2019 including carrying costs.

8.8 2017/18 GAS COSTS

Centra is also seeking approval of its 2017/18 gas costs and associated gas cost deferral balances as part of this Application. The values discussed in the following sections are not finalized yet and are based on outlooks of Centra's 2017/18 gas costs and non-Primary Gas cost deferral account balances using actual results for the months of November 2017 through April 2018, with the remaining months based on forecast figures using futures market prices as of May 15, 2018.

Centra will provide the 2017/18 amounts based on final actual results to October 31, 2018 as part of the pre-hearing update to be filed prior to the commencement of the oral hearing related to this Application. Schedule 8.8.0 shows that Centra's current outlook for its total gas costs for 2017/18 is $185.0 million relative to the $211.2 million interim approved forecast (line 36).

8.8.1 2017/18 Primary Gas PGVA

Schedule 8.8.1 provides details of Centra's outlook of its monthly Primary Gas PGVA balances for the 2017/18 Gas Year. Centra currently anticipates that its total Primary Gas costs for 2017/18 will total $[redacted] (line 12). 1a

8.8.2 2017/18 Supplemental Gas PGVA

Schedule 8.8.2(a) sets out the monthly detail of Centra's current outlook for the 2017/18 Supplemental Gas PGVA. Schedule 8.8.2(b) provides a comparison of this outlook to the interim approved forecast. The major variances contributing to the outlook year-end residual balance of $[redacted] (Schedule 1e 8.8.2(b), line 19) are as follow:

- The average unit cost of Supplemental Gas purchases, excluding Alternate Supply Service, is outlooked at [redacted]. This compares to the originally forecast 1a average unit cost of [redacted] currently being recovered in customers' Supplemental Gas base rates (both on line 23 of Schedule 8.8.2(b)). This unit cost differential, multiplied by the [redacted] GJ of Supplemental Gas purchases 1d currently forecast to be required to serve system supply requirements over the course of the year (line 21 of Schedule 8.8.2(b)), accounts for an $[redacted]. 1e
- A variance of $0.3 million owing to Centra is attributable to the rounding of Supplemental Gas billing percentages to the nearest whole percentage point.
- An [redacted] owing to customers relates to 1e carrying costs to July 31, 2019 (line 17 of Schedule 8.8.2(b)).

The outlook balance of $[redacted] as at July 31, 2019 is displayed 1e on line 19 of Schedule 8.8.2(b). Figure 8.13 below provides a summary recap of the account variances discussed above.

Figure 8.13

2017/18 Supplemental Gas PGVA		
Variance Explanation	**Owing to Centra / (Owing to Customers) in $ Millions**	
Average Unit Cost of Purchases [redacted] than Forecast	[redacted]	1a
Billing Percentage Rounding	$0.3	
Carrying Costs	[redacted]	1e
Total	[redacted]	

8.8.3 2017/18 Transportation PGVA

Schedule 8.8.3(a) shows the monthly detail for the 2017/18 Transportation PGVA outlook, where a balance of $4.2 million refundable to customers is forecast as at October 31, 2018 (line 36). Schedule 8.8.3(b) shows a comparison of outlook versus approved 2017/18 Transportation PGVA inflows and outflows, including $0.1 million of carrying costs for the period of November 1, 2018 through July 31, 2019 that results in a \$4.3 million balance owing from Centra. The major contributors to the expected residual balance are as follow:

- TCPL Mainline fixed transportation costs are expected to be \$[redacted] as shown on line 4. 1e
    - Abandonment Surcharge costs will be \$[redacted] than interim approved amounts due to NEB-approved [redacted] to abandonment surcharge rates relative to the forecast approved on an interim basis in Order 108/15. 1e
    - Fixed transportation tolls will be \$[redacted] in 2017/18 compared to the interim approved forecast as a result of a 2% Mainline toll [redacted] implemented on January 1, 2018. 1e
    - The remaining \$[redacted] pertains to the previously discussed 1,000 GJ/day of Empress to MDA annual FT capacity assigned to Centra by a former T-Service customer effective April 1, 2017. 1e
- [redacted] costs (Schedule 8.8.3(b) line 5) are expected to be \$[redacted] than forecast as a result of Centra holding [redacted] compared to forecast. [redacted]. 1a 1c 1c
- ANR and GLGT fixed transportation costs are expected to be a total of approximately \$[redacted] than forecast as the result of two factors (Schedule 8.8.3(b), lines 6-7): 1e
    - CAD/US exchange rates are expected to average \$1.27 CAD/US during 2017/18 versus the \$1.25 CAD/US embedded in currently approved base rates, which will [redacted] ANR and GLGT fixed costs by \$[redacted]. 1e
    - The previously discussed incremental seasonal storage capacity of 1 PJ contracted by Centra effective June 1, 2016 will [redacted] ANR fixed costs by an [redacted]. 1e
- Variable storage transportation, injection and withdrawal costs are expected to be \$[redacted] than forecast (Schedule 8.8.3(b), lines 13-16 & 18) mainly 1e

as a result of storage withdrawals [redacted]. 1a

- Delivered service imputed transportation costs contribute a variance component of $[redacted] (Schedule 8.8.3(b), lines 17 & 19). [redacted]. 1a 1a, 1c
- CM revenue is currently forecast to be $0.8 million less than the $5.1 million five year average embedded in currently approved base rates as shown on line 25 of Schedule 8.8.3(b).
- Transportation WACOG outflows for the year are currently outlooked at $5.7 million higher than forecast (Schedule 8.8.3(b), line 31) due to higher than forecast customer consumption. This results from a combination of colder than normal weather experienced thus far during the 2017/18 Gas Year, combined with higher overall throughput on a weather normalized basis as a result of the return of two former T-Service customers to System Supply Service since Centra's currently approved base rates were established in Order 108/15. Measured on an EHDD basis, the 2017/18 Gas Year is presently expected to be [redacted]% colder than normal based on a combination of actual data for the period of 1d November 2017 through April 2018 and normal EHDD for the remaining gas months through October 2018.
- Carrying costs forecast to July 31, 2019 contribute an amount of $0.3 million owing to customers (Line 33 of Schedule 8.8.3(b)).

Figure 8.14 below provides a summary of the variances contributing to the 2017/18 Transportation PGVA outlook residual balance of $4.3 million owing to customers as at July 31, 2019 (line 35 of Schedule 8.8.3(b)), along with the directional contribution of each to the outlook balance.

Figure 8.14

2017/18 Transportation PGVA	
Variance Explanation	**Owing to Centra / (Owing to Customers) in $ Millions**
Abandonment Surcharges Greater than Interim Approved	[redacted]
TCPL Mainline Toll Decrease Effective January 1, 2018	[redacted]
T-Service Capacity Assignment to Centra	[redacted]
[redacted]	[redacted]
Higher than Forecast CAD/US Exchange Rates	[redacted]
Storage Capacity Increase	[redacted]
Lower than Forecast Variable Storage Transportation, Injection and Withdrawal Costs	[redacted]
Delivered Service Imputed Transportation Costs	[redacted]
CM Revenues Lower than Forecast	$0.8
WACOG Outflows Greater than Forecast due to Colder Than Normal Weather and Increased Weather Normalized Consumption by Customers	($5.7)
Carrying costs	($0.3)
Total*	**($4.3)**

1a, 1e

* Difference attributable to rounding.

8.8.4 2017/18 Distribution PGVA

Schedule 8.8.4(a) details the 2017/18 Distribution PGVA inflows and outflows by month. Schedule 8.8.4(b) shows a comparison of outlook and approved 2017/18 Distribution PGVA annual inflows and outflows.

The largest contributor to the outlook year-end balance results from lower 2017/18 natural gas commodity market prices and associated UFG cost inflows compared to those embedded in currently approved distribution base rates, which accounts for $0.6 million of the $0.7 million year-end balance owing to customers (Line 3, Schedule

8.8.4(b)). The remaining \$0.1 million (line 8, Schedule 8.8.4) pertains to higher than forecast throughput due to the colder than normal weather and increased weather-normalized consumption by customers discussed previously. The forecast balance as at July 31, 2019 including applicable carrying costs equates to \$0.7 million owing to customers, as summarized in Figure 8.15 below.

Figure 8.15

2017/18 Distribution PGVA	
Variance Explanation	**Owing to Centra / (Owing to Customers) in \$ Millions**
Lower than Forecast Unit Costs on UFG Inflows	(\$0.6)
Greater than Forecast WACOG Outflows due to Colder Weather and Increased Volumes	(\$0.1)
Carrying Costs	(\$0.0)
Total	**(\$0.7)**

8.8.5 2017/18 Heating Value Margin Deferral Account

Schedule 8.8.5 shows outlook inflows and outflows for the 2017/18 Heating Value Margin Deferral Account. During the months of November 2017 through April 2018, heating values ranged from 38.17 $GJ/10^3m^3$ to 38.44 $GJ/10^3m^3$ and averaged 38.34
$GJ/10^3m^3$, as compared to the standard of [redacted] $GJ/10^3m^3$ embedded in Centra's rates. 1d
Schedule 8.8.5, line 16 displays the resulting \$[redacted] 1e
that has accumulated thus far this year and also includes carrying costs to July 31, 2019.

8.8.6 Summary of All Prior Period Non-Primary Gas Cost Deferral Balances to July 31, 2019

The July 31, 2019 Prior-Period Gas Cost Deferrals Account balance will be comprised of the final actual residual balance in the October 31, 2015 Prior-Period Gas Cost Deferrals Account and the final actual balances accumulated in the 2015/16, 2016/17 and

2017/18 non-Primary Gas PGVA accounts. As stated at the outset of this section, the outlooked balances for the various 2017/18 accounts will be updated with final actual figures after the conclusion of the 2017/18 Gas Year and prior to the commencement of the public hearing to review this Application.

Based on the various values discussed in the immediately preceding sections, Schedule 8.8.6 provides a summary of the various account balances that Centra intends to close out to a new July 31, 2019 Prior Period Gas Cost Deferrals Account in order to dispose of these amounts via rate riders over the 12-month period from August 1, 2019 through July 31, 2020 (subject to approval). These 13 gas cost deferral account balances net to a $6.4 million credit balance owing to customers (Line 22 of Schedule 8.8.6). The allocation of these amounts to the various customer classes and the calculation of rate riders to dispose of them in rates, as well as the resulting rate impacts by customer class, is provided in the Cost Allocation and Rate Design material in Tab 10 and the Proposed Rates and Customer Impacts materials in Tab 11 of this Application.

8.9 <u>2018/19 GAS YEAR GAS COST FORECAST</u>

This section provides a discussion and estimate of gas costs for the forecast period of November 1, 2018 to October 31, 2019. This forecast is based on natural gas futures market prices as of May 15, 2018.

- Schedule 8.9.1 summarizes Centra's forecast fixed and variable transportation unit costs, commodity unit supply prices, CAD/USD exchange rates, fuel ratios, UFG and heating values.
- Schedule 8.9.2 summarizes forecast contract demand levels and normal weather year purchase gas requirements to the Manitoba load.
- Schedules 8.9.3(a) and (b) summarize forecast gas costs grouped into fixed transportation costs, variable transportation costs, supply costs and other costs.
- Schedule 8.9.4 summarizes the overall difference between forecast 2018/19 non-Primary Gas costs and the forecast WACOG recoveries that would occur over the period if the existing base rates that were first implemented on November 1, 2015 were to remain in place.

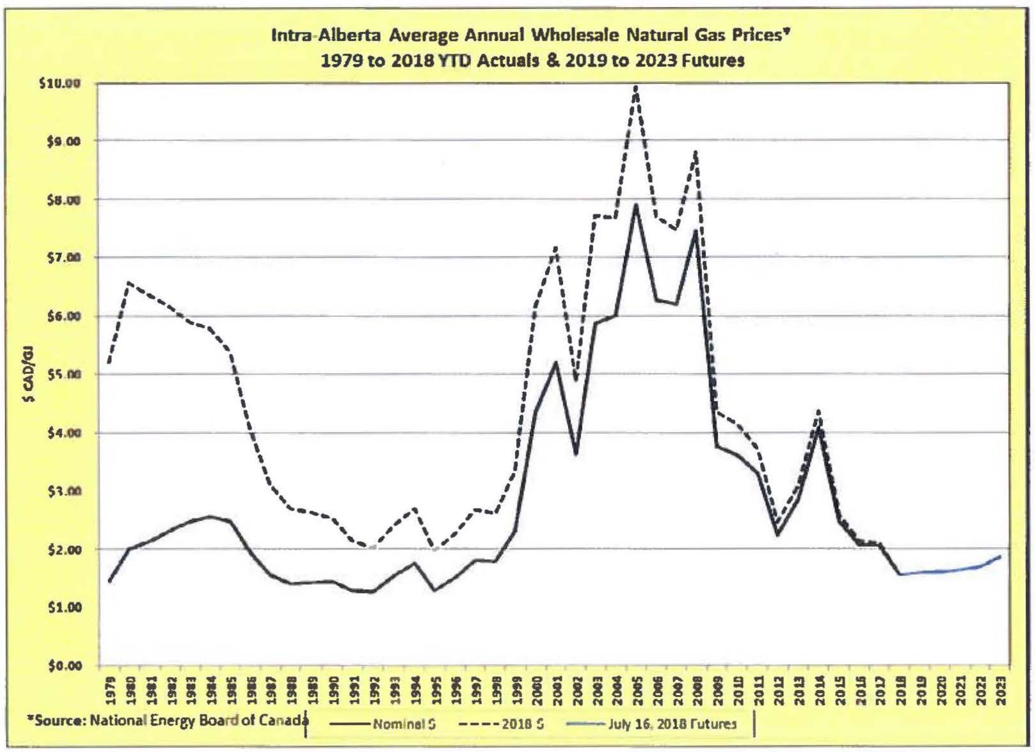
- Column 1 sets out the forecast WACOG recoveries that would take place leaving existing approved base rates unchanged for the 2018/19 forecast period.
- Column 2 summarizes the gas costs forecast for the 2018/19 Gas Year in terms of Primary Gas, Supplemental Gas, Transportation, and Distribution components.
- Column 3 shows the $3.8 million net non-Primary Gas base rate reduction (line 10) required due to the difference between forecast 2018/19 non-Primary Gas costs and the costs that would be recovered leaving existing non-Primary Gas base rates in place.

- Schedule 8.9.5 details differences resulting from the comparison of the 2018/19 Gas Year Forecast and the last approved Interim Forecast.

8.9.1 Natural Gas Market Analysis

Natural gas prices, both spot and futures, continue at multi-generation lows. 2018 year-to-date average intra-Alberta wholesale spot prices, at $1.55 CAD/GJ, are nearly identical to prices 40 years ago in 1979 in absolute dollar terms. After adjusting for changes in the Canadian Consumer Price Index since that time, they are 70% lower today. Recent prices are more than 80% lower than the all-time high reached in 2005 in nominal terms and are 85% lower in real dollar terms. Current futures market prices indicate that forward buyers and sellers do not expect prices to change materially from current levels in the foreseeable future. The past 40 years of intra-Alberta wholesale gas prices, in nominal and inflation-adjusted dollars, as well as current intra-Alberta futures market prices, are shown in Figure 8.16 below:

Figure 8.16



These favourable natural gas prices are the result of unprecedented growth of domestic supplies driven by technological innovation. A decade ago, policy makers believed that North America would increasingly be unable to supply its own gas needs and would become increasingly reliant on large scale imports of liquefied natural gas ("LNG") from overseas regions such as the Middle East and Russia. Today's world, as it relates to natural gas, bears little resemblance to the one that was predicted approximately ten years ago.

The foregoing is not confined to the U.S. In Canada too, assessments of the natural gas resource base have grown dramatically in recent years. The Alberta and B.C. governments have estimated their shale gas resource bases at 3,400[4] and 3,300[5] trillion

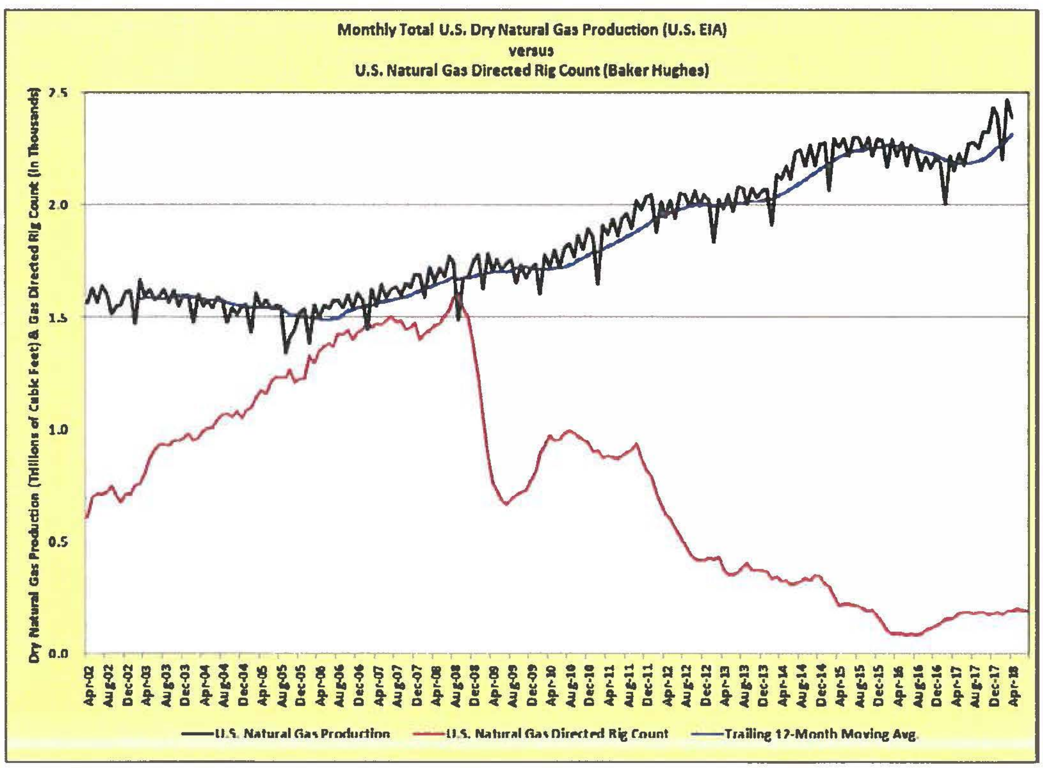
[4] *Summary of Alberta's Shale and Siltstone-Hosted Hydrocarbon Resource Potential,* Alberta Energy Resources Conservation Board, June 2016

[5] *British Columbia's Oil and Gas Reserves and Production Report*, B.C. Oil and Gas Commission, 2015

cubic feet ("Tcf") respectively. Canada currently consumes approximately 3 Tcf/year for domestic purposes. As well, most other provinces in Canada are now being found to be endowed with significant gas resources of their own that is locked in widespread shale and other tight geologic formations.

Overall, the North American natural gas story is one of doing much more with significantly less. As is shown in Figure 8.17 below, since natural gas prices last peaked in 2008, producers in the U.S. (which is the source of more comprehensive data compared to Canada) have increased overall natural gas production by 60%, while at the same time reducing the number of active gas-directed drilling rigs by 90%, which has helped contribute to reducing wholesale market prices in Western Canada by nearly 80%.

Figure 8.17



As a result of Centra's upstream gas cost pass-through mechanism, whereby all of Centra's upstream commodity, transportation and storage costs are passed directly though to its customers in their rates with no mark-up or profit (a mechanism typical to regulated natural gas utilities in North America), the results of the industry's cost reduction efforts are benefitting Centra's ratepayers. Centra's 2018/19 gas cost forecast, which totals $177.3 million, is discussed in the sections that follow.

8.9.2 Forecast Purchase Requirements

Consumption volumes and customer numbers from November 1, 2018 to October 31, 2019 are based on Centra's most recent normal weather customer and volume forecast as provided in Appendix 7.1 of Tab 7 of this Application. The gas cost estimate considers forecast purchase requirements as detailed on Schedule 8.9.2 that are based on Centra's projection of Sales Service (system supply and marketer supply under the WTS) and T-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 averages and is reflective of typical UFG losses.

8.9.3 Primary Gas Direct to Load

Western Canadian supply costs for Primary Gas for the forecast period from November 1, 2018 to October 31, 2019 are based on the terms of Centra's Western Canadian supply contract effective November 1, 2018, which runs for a two year term until October 31, 2020. Monthly average Primary Gas supply prices delivered directly to Centra's load are forecast to range between $[redacted] and $[redacted] over the forecast period and average $[redacted] on a volume-weighted basis as provided on Schedule 8.9.1, line 54. 1a

8.9.4 Supplemental Gas Direct to Load

The forecast costs of Supplemental Gas supplies are priced based on Emerson futures market prices. The unit cost of Supplemental Gas supplied direct to the load is forecast to range between $[redacted] and $[redacted] and average $[redacted] on a volume-weighted basis as shown on line 63 of Schedule 8.9.1. 1a

8.9.5 Alternate Supply Service

Centra supplies Interruptible customers with Alternate Supply Service on a best efforts basis during periods when demand is forecast to exceed Centra's firm deliverability, as described in Section 8.1.1. Because Centra cannot anticipate the decisions that each Interruptible customer will make when faced with the choice of accepting Alternate Supply Service or curtailing its natural gas consumption, this gas cost forecast excludes costs and volumes associated with Alternate Supply Service.

8.9.6 Transportation and Storage Costs

TCPL Mainline tolls embedded in the 2018/19 gas cost forecast reflect NEB–approved interim tolls that became effective January 1, 2018. The costs associated with Centra's current U.S. transportation and storage arrangements are based on the discounted toll structure reflected in Centra's 7-year contracts with ANR and GLGT. The ANR costs reflected in the 2018/19 gas cost forecast also include the annual fixed costs of $148,000 USD associated with the additional 1 PJ of seasonal storage capacity contracted by Centra. Other pipeline tolls (ANR, GLGT, TransGas, MIPL and CTHI) are based on the transportation tolls in these pipelines' respective tariffs as of May 15, 2018.

8.9.7 Storage Withdrawals

Centra's storage forecast is based on the final balances in each of the gas storage accounts at the end of the 2017/18 winter withdrawal season as of March 31, 2018, plus the forecast cost of injections during the summer 2018 re-fill season. The October 31, 2018 outlook of average inventory cost for each component follows in Figure 8.18 below (Lines 55, 64, and 73 of Schedule 8.9.1):

Figure 8.18

Primary Gas in storage		[redacted]	
Supplemental Gas in storage			
Inventoried Storage Transportation Costs			

1a

The forecast cost of storage withdrawals for the 2018/19 winter season was determined using these average inventory costs.

8.9.8 U.S. Exchange Rate

The forecast exchange rates applied to U.S. gas purchases and U.S. transportation and storage costs are $1.28 CAD/USD for the November 1, 2018 to March 31, 2019 period, and $1.26 CAD/USD for the period of April 1, 2019 through October 31, 2019 as identified on Schedule 8.9.1, line 77.

8.9.9 CM Forecast

The five-year average of Centra's actual CM revenues has been updated to $4.4 million from the previously approved $5.1 million. The $4.4 million forecast amount is based on the most recent 5-year rolling average of Centra's actual CM results through to April 30, 2018 (line 33 of Schedule 8.9.3(a)) as outlined in Figure 8.19 below.

Figure 8.19

	CM Revenue ($ Millions)
May 2013 - April 2014	$5.9
May 2014 - April 2015	$2.5
May 2015 - April 2016	$2.9
May 2016 - April 2017	$5.2
May 2017 - April 2018	$5.4
5-Year Average	**$4.4**

8.10 FORECAST GAS COSTS FOR THE 2018/19 GAS YEAR

The total forecast cost of gas for the November 1, 2018 to October 31, 2019 Gas Year is $177.3 million. The details in support of this forecast are contained on Schedules 8.9.1 through 8.9.4. Centra's forecast of its non-Primary Gas costs for 2018/19 totals $79.3 million (column 2, line 10 of Schedule 8.9.4).

Centra is seeking interim approval to implement revised Supplemental Gas, Transportation, and Distribution base rates effective August 1, 2019 based on the gas cost information contained in this section of the Application. As indicated on column 3, line 10 of Schedule 8.9.4, Centra is seeking a net decrease in its non-Primary Gas base rates in the amount of $3.8 million. Centra intends to provide an update to its 2018/19 gas cost forecast as part of the pre-hearing update to be filed prior to the commencement of the oral hearing related to this Application.

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 10 and the Proposed Rates and Customer Impacts material in Tab 11 of this Application.