CENTRA GAS MANITOBA INC.
2019/20 GENERAL RATE APPLICATION

PRE-HEARING UPDATE

INDEX

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1.0 OVERVIEW

The purpose of this submission is to describe the Pre-Hearing Update to Centra Gas Manitoba Inc.'s ("Centra") General Rate Application ("Application" or "GRA") originally filed on November 30, 2018.

Section 2.0 describes the updates pertaining to gas costs and gas cost deferral balances that are reflected in this Pre-hearing Update.

Section 3.0 summarizes the updates made to the 2019/20 Cost Allocation Study to reflect changes in gas costs, updated detailed Operating & Administrative ("O&A") budgets for gas operations for 2019/20 as well as changes to the Power Station class contributions to the coincident peak day for the 2019/20 Test Year.

Section 4.0 presents the customer base rate and billed rate impacts.

2.0 GAS COSTS AND GAS COST DEFERRALS UPDATE

The purpose of this section is to describe the updates pertaining to gas costs and gas cost deferral balances. The highlights are as follows:

- 2017/18 Gas Year costs (Schedule 8.8.0) were updated to reflect actual results totaling $187.0 million. The 2017/18 Primary Gas and non-Primary Gas Purchased Gas Variance Accounts ("PGVA") have also been updated to reflect actual results for the entire 2017/18 Gas Year (Schedule 8.8.1, Schedule 8.8.2 (a)&(b), Schedule 8.8.3 (a)&(b), Schedule 8.8.4 (a)&(b) and Schedule 8.8.5).
- 2018/19 Gas Year costs now incorporate actual results for the months of November 2018 through March 2019, and the remaining forecast months are based on futures market prices as of April 26, 2019. The updated outlook of

total gas costs is $210.9 million (Schedule 8.10.0). 2018/19 Primary Gas and non-Primary Gas PGVA balances are provided in Schedule 8.10.1, Schedule 8.10.2 (a)&(b), Schedule 8.10.3 (a)&(b), Schedule 8.10.4 (a)&(b), and Schedule 8.10.5.

- Non-primary gas cost deferral balances to October 31, 2019 (Schedule 8.10.6) have been updated, supporting the net movement from a $6.4 million credit balance owing to customers as per the 2019/20 GRA filed on November 30, 2018 to a $21.3 million credit balance owing to customers as reflected in this Pre-hearing Update. The vast majority of the additional credit balance owing back to customers is a result of the inclusion of the 2018/19 non-Primary Gas PGVAs, which are described in this update.
- Centra's Application for approval of rates effective November 1, 2019 now reflects forecast non-Primary Gas costs for the 2019/20 Gas Year (vs. the 2018/19 Gas Year as originally filed), the forecast for which (Schedules 8.11.1 to 8.11.5) is based on an April 26, 2019 futures market price strip. As noted on Schedule 8.11.4, the forecast of 2019/20 gas costs is $185.0 million, of which $71.1 million is related to non-Primary Gas costs in comparison to $80.6 million non-Primary Gas costs recoverable at existing base rates. This difference represents a $9.5 million decrease from the non-Primary Gas costs that are recoverable through existing base rates. A discussion of forecast gas costs for the 2019/20 Gas Year is also provided in this update.

2.1 2018/19 Gas Costs

Centra is seeking interim approval of its outlook 2018/19 gas costs and associated gas cost deferral balances through this Pre-hearing Update. The values discussed in the following sections are not final. They are based on outlooks of Centra's 2018/19 gas costs and non-Primary Gas cost deferral account balances using actual results for the months of November 2018 through March 2019, with the remaining months based on forecast figures using futures market prices as of April 26, 2019. Centra will provide actual 2018/19 amounts to October 31, 2019 as part of a future proceeding. Schedule 8.10.0 shows that Centra's current outlook for its total gas costs for 2018/19 is $210.9 million relative to the $211.2 million interim approved forecast (line 36).

2.1.1 2018/19 Primary Gas PGVA

Schedule 8.10.1 provides details of the monthly Primary Gas PGVA balances for the 2018/19 Gas Year. Centra's total Primary Gas cost outlook for 2018/19 is $[redacted] 1a (line 12).

2.1.2 2018/19 Supplemental Gas PGVA

Schedule 8.10.2(a) sets out the monthly detail of Centra's current outlook for the 2018/19 Supplemental Gas PGVA. Schedule 8.10.2(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 8.10.2(b), line 19) are as follows:

- The average unit cost of Supplemental Gas purchases, excluding Alternate Supply Service, equates to an outlook of [redacted]. This compares to the 1a average unit cost of [redacted] currently being recovered in customers' Supplemental Gas base rates (both on line 23 of Schedule 8.10.2(b)). This unit cost differential, multiplied by the [redacted] GJ of Supplemental Gas 1d purchases currently forecast to be required to serve system supply requirements over the course of the year (line 21 of Schedule 8.10.2(b)), 1e accounts for a $[redacted].
- A variance of $0.2 million owing to Centra is attributable to the rounding of Supplemental Gas billing percentages to the nearest whole percentage point.
- Over the course of the 2018/19 Gas Year carrying costs total an outlook 1e figure of [redacted] (line 17 of Schedule 8.10.2(b)), representing an amount [redacted].

The outlook balance of $[redacted] as at October 31, 2019 is 1e displayed on line 19 of Schedule 8.10.2(b). Figure 2.1 below provides a summary recap of the account variances discussed above.

Figure 2.1

2018/19 Supplemental Gas PGVA		
Variance Explanation	**Owing to Centra / (Owing to Customers) in $ Millions**	
Average unit cost of purchases [redacted] than that being recovered in Supplemental Gas base rates	[redacted]	1a
Billing percentage rounding	$0.2	
Carrying costs	[redacted]	1e
Total	[redacted]	

2.1.3 2018/19 Transportation PGVA

Schedule 8.10.3(a) shows the monthly detail for the 2018/19 Transportation PGVA outlook, where a balance of $11.4 million refundable to customers is forecast as at October 31, 2019 (line 36) and Schedule 8.10.3(b) shows a comparison of the outlook to the interim approved forecast. The major contributors to the expected residual balance are as follows:

- TCPL Mainline fixed transportation costs are expected to be $[redacted] as shown on line 4. 1e
    - Fixed transportation costs will be [redacted] in 2018/19 compared to the interim approved forecast as a result of a combination of Centra holding more TCPL Firm Transportation, resulting in a $[redacted], and toll reductions implemented on January 1, 2018 and February 1, 2019 that result in a [redacted] as compared to the interim approved toll forecast. 1e 1e 1e
    - Abandonment Surcharge costs will be [redacted] than interim approved amounts (Order 108/15) due to NEB-approved amendments to abandonment surcharge rates relative to forecast and the increase in Centra's transportation capacity. 1e
    - 1,000 GJ/day of Empress to MDA annual FT capacity was assigned to Centra by a former T-Service customer for the period through March 31, 2019 [redacted] as compared to interim approved rates. 1e

[redacted] costs (Schedule 8.10.3(b) line 5) 1a are expected to be $[redacted] than forecast as a result of Centra [redacted] 1c

- ANR and GLGT fixed transportation costs are expected to be a total of approximately $[redacted] than forecast as the result of two factors 1e (Schedule 8.10.3(b), lines 6-7):
    - o CAD/USD exchange rates are expected to average $1.34 CAD/USD during 2018/19 versus the $1.25 CAD/USD embedded in currently approved base rates, which will [redacted] ANR and GLGT fixed costs by 1e $[redacted].
    - o The incremental seasonal storage capacity of 1 PJ contracted by Centra effective June 1, 2016 will [redacted] ANR fixed costs by an 1e [redacted].
- Variable storage transportation, injection and withdrawal costs are expected to be $[redacted] than forecast (Schedule 8.10.3(b), lines 13-16 & 18) 1e mainly as a result of storage withdrawals [redacted] 1a.
- Delivered service imputed transportation costs contribute a net variance component of $[redacted] (Schedule 8.10.3(b), lines 1a 17 & 19). [redacted] 1a, 1c.
- Capacity Management revenue is currently forecast to be $1.0 million greater than the $5.1 million five year average embedded in currently approved base rates as shown on line 25 of Schedule 8.10.3(b).
- Transportation WACOG outflows for the year are currently outlooked at $6.0 million higher than forecast (Schedule 8.10.3(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 2018/19 Gas Year, combined with higher overall throughput on a weather normalized basis as a result of T-Service customer migration to Sales Service since Centra's currently approved base rates were established in Order 108/15. Measured

on an EHDD basis, the 2018/19 Gas Year is presently expected to be [redacted]% colder than normal based on a combination of actual data for the period of November 2018 through March 2019 and normal EHDD for the remaining gas months through October 2019. 1d

- Carrying costs forecast to October 31, 2019 contribute an amount of $0.5 million owing to customers (Line 33 of Schedule 8.10.3(b)).

Figure 2.2 below provides a summary of the variances contributing to the 2018/19 Transportation PGVA outlook residual balance of $11.4 million owing to customers as at October 31, 2019 (line 35 of Schedule 8.10.3(b)), along with the directional contribution of each to the outlook balance.

Figure 2.2

2018/19 Transportation PGVA	
Variance Explanation	**Owing to Centra / (Owing to Customers) in $ Millions**
TCPL FT Demand Level Increase	[redacted]
TCPL Mainline Toll Decreases effective January 1, 2018 & February 1, 2019	[redacted]
Abandonment Surcharges Greater than Interim Approved	[redacted]
T-Service Capacity Assignment to Centra	[redacted]
[redacted]	[redacted]
Higher than Forecast CAD/USD 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 Higher than Forecast	($1.0)
WACOG Outflows Greater than Forecast due to Colder Than Normal Weather and Increased Weather Normalized Consumption by Customers	($6.0)
Carrying costs	($0.5)
Total*	**($11.4)**

1a, 1e

* Difference attributable to rounding.

2.1.4 2018/19 Distribution PGVA

Schedule 8.10.4(a) details the 2018/19 Distribution PGVA inflows and outflows by month. Schedule 8.10.4(b) shows a comparison of outlook and interim approved Distribution PGVA annual inflows and outflows.

The largest contributor to the outlook year-end balance results from lower UFG cost inflows associated with lower 2018/19 natural gas commodity market prices compared to those embedded in currently approved distribution base rates, which accounts for a $0.2 million year-end balance owing to customers (Line 3, Schedule 8.10.4(b)). An additional $0.1 million owing to customers (line 8, Schedule 8.10.4(b)) pertains to higher than forecast throughput due to the colder than normal weather and increased weather-normalized consumption by customers discussed previously. The outlook balance as at October 31, 2019 including applicable carrying costs equates to $0.3 million owing to customers, as summarized in Figure 2.3 below.

Figure 2.3

2018/19 Distribution PGVA	
Variance Explanation	**Owing to Centra / (Owing to Customers) in $ Millions**
Lower than Forecast Unit Costs on UFG Inflows	($0.2)
Greater than Forecast WACOG Outflows due to Colder Weather and Increased Volumes	($0.1)
Total	**($0.3)**

2.1.5 2018/19 Heating Value Margin Deferral Account

Schedule 8.10.5 shows outlook inflows and outflows for the 2018/19 Heating Value Margin Deferral Account. During the months of November 2018 through March 2019, heating values ranged from 38.18 $GJ/10^3m^3$ to 38.34 $GJ/10^3m^3$ and averaged 38.24 $GJ/10^3m^3$, as compared to the standard of [redacted] $GJ/10^3m^3$ embedded in 1d
Centra's rates. Schedule 8.10.5, line 10 displays the resulting $[redacted] 1e
that has accumulated thus far this year and also includes carrying costs to October 31, 2019.

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

The October 31, 2019 Prior-Period Gas Cost Deferrals Account balance will be comprised of the actual residual balance in the October 31, 2015 Prior-Period Gas Cost Deferrals Account and the actual balances accumulated in the 2015/16, 2016/17 and 2017/18 non-Primary Gas PGVA accounts. In addition, the outlook balances in respect of the 2018/19 non-Primary Gas PGVA accounts are now included through this Pre-hearing Update.

Schedule 8.10.6 provides a summary of the various account balances that Centra intends to close out to the October 31, 2019 Prior Period Gas Cost Deferrals Account in order to dispose of these amounts via rate riders over the 12-month period from November 1, 2019 through October 31, 2020 (subject to approval). The October 31, 2019 Prior-Period Gas Cost Deferrals Account balance nets to a $21.3 million balance owing to customers (Line 28 of Schedule 8.10.6). 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 3.0 and the Proposed Rates and Customer Impacts materials in Tab 4.0.

2.2 2019/20 Gas Year Gas Cost Forecast

This section provides a discussion and estimate of gas costs for the forecast period of November 1, 2019 to October 31, 2020. This forecast is based on natural gas futures market prices as of April 26, 2019.

- Schedule 8.11.1 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 8.11.2 summarizes forecast contract demand levels and normal weather year purchase gas requirements to the Manitoba load.
- Schedules 8.11.3(a) and (b) summarize forecast gas costs grouped into fixed transportation costs, variable transportation costs, supply costs and other costs.
- Schedule 8.11.4 summarizes the overall difference between forecast 2019/20 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 2019/20 forecast period.
- Column 2 summarizes the gas costs forecast for the 2019/20 Gas Year in terms of Primary Gas, Supplemental Gas, Transportation, and Distribution components.
- Column 3 shows the $9.5 million net non-Primary Gas base rate reduction (line 10) proposed due to the difference between forecast 2019/20 non-Primary Gas costs and the costs that would be recovered leaving existing non-Primary Gas base rates in place.

- Schedule 8.11.5 details differences resulting from the comparison of the 2019/20 Gas Year Forecast and the last approved Interim Forecast.

2.2.1 Forecast Purchase Requirements

Consumption volumes and customer numbers from November 1, 2019 to October 31, 2020 are based on Centra's most recent normal weather customer and volume forecast as provided in Appendix 7.6 of the Supplement to the 2019/20 General Rate Application. The gas cost estimate considers forecast purchase requirements as detailed on Schedule 8.11.2 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.

2.2.2 Primary Gas Direct to Load

Western Canadian supply costs for Primary Gas for the forecast period from November 1, 2019 to October 31, 2020 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] over 1a
the forecast period and average $[redacted] on a volume-weighted basis as provided on Schedule 8.11.1, line 61.

2.2.3 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 71 of Schedule 8.11.1. 1a

2.2.4 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 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.

2.2.5 Transportation and Storage Costs

TCPL Mainline tolls embedded in the 2019/20 gas cost forecast reflect NEB–approved final tolls that came into effect February 1, 2019 and which are to remain in place through December 31, 2020.

TCPL Abandonment Surcharges have been updated to incorporate TransCanada's most recent filing (NEB Filing ID: A99077) that seeks approval to revise Abandonment Surcharges effective July 1, 2019 through December 31, 2019.

The costs associated with Centra's current U.S. transportation and storage arrangements for the forecast gas months of November 2019 through March 2020 are based on the discounted toll structure reflected in Centra's 7-year contracts with ANR and GLGT ending March 31, 2020 including the additional 1 PJ of seasonal storage capacity contracted. Centra's proposed storage and transportation arrangements are embedded in the 2019/20 gas cost forecast commencing April 1, 2020.

Remaining pipeline tolls (e.g. TransGas, MIPL and CTHI) are based on the transportation tolls in these pipelines' respective tariffs as of April 26, 2019.

2.2.6 Storage Withdrawals

Centra's storage forecast is based on the balances in each of the gas storage accounts at the end of the 2018/19 winter withdrawal season as of March 31, 2019, plus the forecast cost of injections during the summer 2019 re-fill season. The October 31, 2019 outlook of average inventory cost for each component follows in Figure 2.4 below (Lines 62, 72, and 81 of Schedule 8.11.1).

Figure 2.4

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

1a

The forecast cost of storage withdrawals for the 2019/20 winter season was determined using these average inventory costs.

2.2.7 U.S. Exchange Rate

The forecast exchange rates are $1.30 CAD/USD for the November 1, 2019 to March 31, 2020 period, and $1.28 CAD/USD for the period of April 1, 2020 through October 31, 2020 as identified on Schedule 8.11.1, line 85.

2.2.8 CM Forecast

The five-year average of Centra's actual CM revenues has been updated to $4.4million 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 March 31, 2019 (line 38 of Schedule 8.11.3(a)) as outlined in Figure 2.5 below.

Figure 2.5

	CM Revenue ($ Millions)
April 2014 – October 2014	$1.0
November 2014-October 2015	$3.1
November 2015–October 2016	$5.1
November 2016–October 2017	$4.7
November 2017–October 2018	$4.6
November 2018-March 2019	$3.5
5-Year Average	**$4.4**

2.2.9 Forecast Gas Costs for the 2019/20 Gas Year

The total forecast cost of gas for the November 1, 2019 to October 31, 2020 Gas Year is $185.0 million. The details in support of this forecast are contained on Schedules 8.11.1 through 8.11.4. Centra's forecast of its non-Primary Gas costs for 2019/20 totals $71.1 million (column 2, line 10 of Schedule 8.11.4).

Centra is seeking interim approval to implement revised Supplemental Gas, Transportation, and Distribution base rates effective November 1, 2019 based on the gas cost information contained in this section of the Application. As indicated on column 3, line 10 of Schedule 8.11.4, Centra is seeking a net decrease in its non-Primary Gas base rates in the amount of $9.5 million.

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 3.0 and the Proposed Rates and Customer Impacts material in Tab 4.0 of this Application.

3.0 COST ALLOCATION AND RATE DESIGN UPDATE

Centra has updated its 2019/20 Cost Allocation Study to reflect changes to:

- Estimates of non-Primary Gas costs for the 2019/20 Gas Year have been updated to include an April 26, 2019 futures market price strip as provided in

Section 2.0 of this Pre-Hearing Update, the impact of updated TCPL tolls flowing from RH-001-2018 and other updates.

- Balances of the non-Primary PGVA accounts accumulated between November 1, 2015 and October 31, 2019 (with updated carrying costs to October 31, 2019) as provided in Section 2.0.
- 2019/20 O&A budget by program costs as outlined in the Section 3.1. Centra's overall 2019/20 O&A budget continues to be $60.5 million for rate setting purposes (or $61.2 million as per financial reporting; the reconciliation of the difference is provided in the Appendix 5.12 of the November 30, 2018 Application). The updated budget by program results in changes to the allocation of non-gas costs to customer classes.
- Power Station class contribution to the coincident system peak day forecast for 2019/20 Test Year. As outlined in Section 3.2 Centra has modified the methodology for calculating the coincident system peak day forecast of the Power Station resulting in an increase of the peak day volumes for this customer class. As the system peak data is used as a component of the Peak and Average allocation factor(s), the increase in the coincident system peak day forecast of the Power Station has resulted in a small increase to the allocation of costs to the Power Station class.

3.1 Non-Primary Gas costs

As shown in the Figure 3.1 below, in this Pre-Hearing Update, Centra is proposing to recover a total of $71.1 million in Non-Primary Gas costs through base rates to be effective November 1, 2019. The non-Primary Gas costs are approximately $8.2 million lower compared to the Non-Primary Gas Costs shown in Figure 10 of the March 22, 2019 Supplement and are approximately $9.7 million lower than those costs approved in Centra's 2015/16 Cost of Gas Application. The decrease in Non-Primary Gas costs compared to Centra's March 22, 2019 filing is a result of a decline of approximately $[redacted] in forecasted transportation costs primarily due to 1a
changes in TCPL Tolls and the forecast [redacted] of Supplemental Gas costs of
approximately [redacted]. 1a

Figure 3.1: 2019/20 Non-primary Gas Costs ($000s)

	Approved 2015/16 COG	March 22, 2019 Supplement 2019/20 GRA[1]	July 24, 2019 Pre-Hearing Update 2019/20 GRA[2]	March 22 vs July 24 Inc/(Dec)	
Transportation	[redacted]				
Distribution					
Subtotal					1a, 1e
Supplemental gas					
Total Non-Primary Gas Costs	80,782.8	79,328.8	71,063.4	(8,265.3)	

[1]Based on 2018/19 Forecast Year
[2]Based on 2019/20 Forecast Year

The Figure 3.2 below provides a summary of the allocation of forecasted non-Primary Gas costs of $71.1 million for the period November 1, 2019 to October 31, 2020 to the various rate classes compared to the allocation of $79.3 million in the March 22, 2019 Update (and original filing) and also to the allocation $80.8 million approved in Centra's 2015/16 Cost of Gas Application.

Figure 3.2: Comparison on Non-Primary Gas costs by customer classes ($000s)

	2015/16 COG Approved	March 22, 2019 Supplement 2019/20 GRA	July 24, 2019 Pre-Hearing Update 2019/20 GRA	March 22 vs July 24 Increase/ (Decrease)	
SGS	31,715	32,343	29,412	(2,931)	
LGS	23,427	24,701	22,462	(2,239)	
High Volume Firm	6,690	6,927	6,315	(613)	
Co-op	12	12	11	(1)	
Mainline	307	224	228	4	
Special Contract	[redacted]				2d
Power Stations					
Interruptible	959	881	838	(43)	
Supplemental Firm	[redacted]				1a
Supplemental Interruptible					
Total Non-Primary Gas Costs	80,783	79,329	71,063	(8,265)	

As reflected in Figure 3.2 above, forecast year Non-Primary Gas costs are approximately $8.2 million lower relative to Centra's 2019/20 GRA Supplement filed on March 22, 2019. The small increase in Non-Primary Gas costs allocated to the Mainline, Power Stations and Special Contract customer classes is the result of an increase in the forecast of UFG cost, resulting from the increase in commodity costs.

As part of this Pre-hearing Update, Centra has also updated its Non-Primary Gas Deferral Account Balance to include the 2018/19 PGVAs and carrying costs to October 31, 2019. Centra is now proposing to refund to customers (over a 12-month period beginning November 1, 2019 and ending October 31, 2020) approximately $21.3 million in non-Primary Gas PGVA and other gas cost deferral accounts (Schedule 11.3.1 line 18) compared to $6.4 million in the March 22 Update filing (and original filing). The following Figure 3.3 compares the PGVA balances in the March 22, 2019 filing to the updated PGVA balances in this Pre-Hearing Update.

Figure 3.3: Summary of Oct 31, 2019 Non-Primary Gas Deferral Balances

	March 22, 2019 Supplement	July 24, 2019 Pre-Hearing Update	Increase/ (Decrease)	
Prior Period Non-Primary Gas Costs Deferral	[redacted]			1e
Supplemental PGVA				
Transportation PGVA	20,348,456	13,988,278	(6,360,178)	1a, 1e
Distribution PGVA	(3,317,988)	(4,232,008)	(914,020)	
Capacity Management	(14,758,247)	(21,506,060)	(6,747,813)	
Heating Value	[redacted]			1e
Total (per Sch. 8.10.6, Line 28)	(6,437,117)	(21,337,277)	(14,900,160)	

The $21.3 million balance in Centra's non-Primary gas cost deferral balance includes the actual residual balance in October 31, 2015 Prior-Period Gas Cost Deferral Account, the actual balances accumulated in the 2015/16, 2016/17 and 2017/18 non-Primary Gas PGVA accounts and the outlook balances to October 31, 2019 in respect of the 2018/19 non-Primary Gas PGVA accounts.

Schedules 11.3.0 a), b), c), d) (Update) and Schedule 11.3.0 e) (an additional schedule provided by Centra as part of this Update) summarizes the allocation of the non-Primary Gas PGVA and gas cost deferral accounts as at October 31, 2019 to the various customer classes. Schedule 11.3.1 (Update) provides a Rate Rider unit cost calculation of the $21.3 million of non-Primary Gas PGVA and gas cost deferral accounts.

The following Figure 3.4 provides a summary of the allocated cost by class of the updated non-Primary Gas cost deferral accounts including the Supplemental Gas PGVA balances allocated to each customer class. In this update Centra has continued to allocate the Heating Value Deferral Account on a volumetric basis, based on the existing PUB-approved Cost of Service Study, and consistent with the original Application and Supplement, and recognizes that alternative dispositions of the Heating Value Deferral Account will be discussed at the oral evidentiary portion of the hearing to be held in August.

Figure 3.4: Summary of Gas Year Deferral Balances by Rate Class

PGVA's by Rate Class	Total	SGS	LGS	HVF	Mainline	Interr.	[redacted]
2019/20 Rider - 2015/16 GY	6,033,724	3,024,698	2,451,091	465,287	-38,323	-97,972	
2019/20 Rider - 2016/17 GY	2,536,082	1,498,755	1,185,818	-47,868	-92,885	-95,806	
2019/20 Rider - 2017/18 GY	-16,693,758	-8,263,939	-5,970,447	-2,379,554	-88,997	-286,131	
2019/20 Rider - 2018/19 GY	-13,213,324	-6,524,939	-4,347,969	-2,394,342	13,384	-217,375	
Total	-21,337,276	-10,265,424	-6,681,507	-4,356,478	-206,821	-697,284	

2d, 1e

3.2 Updated Detailed O&A Budgets

Although the total non-gas costs remain unchanged in this filing, the changes to the program costs in Operating & Administrative expenses have resulted in changes to allocation of these costs between classes. Figure 3.5 below provides a summary of the allocation of non-gas costs to various customer classes compared to Mar 22, 2019 filing.

Figure 3.5: Comparison of Non-Gas Costs by Customer Class ($000s)

	2019/20 TY March 22, 2019 Supplement	2019/20 TY July 24, 2019 Pre-Hearing Update	Increase/ (Decrease)
SGS	102,633	102,604	(29)
LGS	32,456	32,286	(170)
High Volume Firm	6,824	6,889	65
Co-op	8	8	(0)
Mainline	2,058	2,052	(6)
Special Contract	2,247	2,278	32
Power Stations	158	198	40
Interruptible	770	779	9
Primary Gas	[redacted]		
Supplemental Firm			
Supplemental Interrupt ble			
Fixed Rate Primary Gas	21	14	(8)
Total Non-Gas Costs of Service	148,519	148,519	(0)

1e

The increase in O&A costs allocated to HVF, SC, PS and INT classes is the result of the increase in program costs such as Customer Inspections, Environment, Distribution

Maintenance and System Performance and Reliability, which are allocated to customer classes in proportion to transmission and distribution mains and distribution service plant. The decrease in O&A costs allocated to SGS and LGS classes resulted from the decrease in program costs such as Dispatch, Billing and Collections and Other that these classes have relatively higher cost responsibility for.

Explanations for programs with costs that changed significantly compared to the information filed as part of the March 22nd Supplement are provided below.

Further, the allocated non-gas costs to be included in the Primary Gas base rate will also slightly increase as a result of this update. Centra is requesting approval of a new updated Primary Gas Overhead Rate (non-gas component) of \$0.98/10^3m^3 (Schedule 10.1.2, lines 47 and 49) compared to \$0.91/10^3m^3 from March 22 Update Filing.

Centra has also updated its Fixed Rate Primary Gas Service ("FRPGS") Program Cost Rate ("PCR"). The revised PCR is \$24.18/10^3m^3 (Schedule 10.1.2, line 49), which is lower than the \$37.67/10^3m^3 included in March 22, 2019 filing and lower than the 31.37/10^3m^3 currently approved by the PUB. The decrease compared to the March filing results from a further reduction in program administration costs forecasted for this service for the 2019/20 test year.

The non-gas cost components within the Supplemental Gas rates have also been updated. The Firm Supplemental gas overhead component is proposed to be \$1.54/10^3m^3 and the Interruptible Supplemental gas overhead component is proposed to be \$1.55/10^3m^3. Figure 3.6 provides the calculation of overhead rates for Supplemental Gas.

Figure 3.6: Calculation of Supplemental Gas Overhead Rate

	2019/20 March 22, 2019 Supplement	2019/20 July 24, 2019 Pre-Hearing Update	
Firm Supplemental OH rate			
Non-gas allocated ($)	[redacted]		1d, 1e
Volumes (10^3m^3)			
Rate/10^3m^3	1.60	1.54	
rate/m^3	0.0016	0.0015	
INT Supplemental OH rate			
Non-gas allocated ($)	[redacted]		1d, 1e
Volumes (10^3m^3)			
Rate/10^3m^3	1.59	1.55	
rate/m^3	0.0016	0.0015	

Centra's overall O&A Expense target for 2019/20 remains unchanged at $61.2 million, consistent with the original Application and the Supplement to the Application filed on March 22, 2019. Figure 3.7 below provides the recently finalized detailed O&A budget by program for 2019/20 along with a comparison to the O&A by program filed in the original Application.

Figure 3.7: Detailed O&A Budget by Program for 2019/20

CENTRA GAS MANITOBA INC.
2019/20 O&A PROGRAM COMPARISON

	2019/20 Approved Budget	2019/20 Test Year Submitted	Change	Notes
Customer Service & Corporate Relations				
Back/middle office services	290	294	(5)	
Billing & collections	7 306	7 705	(399)	1
Customer & public relations	3 959	4 009	(49)	
Customer information systems (banner)	627	534	93	
Customer inspections	8 184	7 151	1 033	2
Customer safety services	1 533	1 285	248	
Dispatch	1 920	2 306	(386)	3
Energy supply, planning & support	2 721	2 869	(149)	
Environment	948	399	549	4
Meter reading	2 497	2 511	(14)	
Rate and regulatory affairs	1 304	944	360	5
Total Customer & public relations	31 288	30 008	1 280	
Operations and Maintenance				
Communication systems	133	135	(2)	
Distribution maintenance	7 005	6 759	247	
Load forecast	107	70	37	
Metering	361	574	(213)	
Plant failures & emergencies	232	303	(71)	
Quality assessment	448	435	13	
Station maintenance	5 106	5 376	(271)	
System performance & reliability	2 662	2 513	149	
Total Operations and Maintenance	16 055	16 165	(110)	
Organizational Support				
Corporate governance	2 297	2 157	141	
Corporate infrastructure	4 591	4 581	10	
Corporate services	2 116	2 010	105	
Departmental support	6 174	5 872	302	6
Operational management	1 638	1 787	(149)	
Total Organizational Support	16 816	16 408	408	
Corporate Allocation & Adjustment				
Depreciation & Taxes	(2 212)	(2 183)	(29)	
Other	(697)	852	(1 549)	7
	(2 909)	(1 331)	(1 579)	
Operating & Adminstrative Expenses	**61 250**	**61 250**	**(0)**	

Explanations have been provided for programs with a significant change.

1. The decrease in the **Billing and Collections program** is primarily due to a reduction of hours required as a result of the discontinuance of accepting bill

payments at all customer service centres.

2. The increase in the **Customer Inspections Program** is primarily due to changes in the activity rates to reflect the current mix of supervisory and technical staff required to support the program as well as a refinement of the hours to align with current and projected averages in customer requested programs such as line locates and equipment inspections.
3. The decrease in the **Dispatch Program** reflects lower staffing levels for the planning and scheduling function as well as reduced activity rates primarily as a result of organizational changes following the VDP.
4. The increase in the **Environment Program** is primarily related to additional environmental investigations required at 35 Sutherland.
5. The increase in the **Rates and Regulatory Affairs Program** reflects an increase in internal labour hours required to support the 2019/20 Gas General Rate Application.
6. The increase in the **Departmental Support Program** is due to the refinement of training and support cost estimates to reflect historical and known requirements.
7. The decrease in **Other** is due to an update of the contingency to align the detailed budget with the approved O&A target. Centra is currently reflecting a negative contingency of $600K which will be managed over the 2019/20 fiscal year to meet the approved target.

3.3 Updated Power Station Coincident Peak Day Forecast

With this update Centra has updated the methodology for calculating the coincident system peak day forecast of the power stations. Historically, the methodology which has been utilized for all rate classes, is to average the peak day contribution by rate class over the previous three years of history to be applied to the forecast. For the power station class the peak day contribution of each customer was independently calculated. Unlike prior forecasts, in the 2018 forecast only one of these customers was contributing to the peak day. The power station customers consume natural gas differently than other customer classes and may not draw from the system during the coincident peak day during the three previous years of history. For this update, the power station class coincident peak day has been calculated using the system coincident peak day contribution over the previous ten years in which the power station class consumed natural gas on the system peak day. The power station class load factor utilized in the forecast is 8.5%. The resulting methodology has increased the power station class's share of the peak day which ensures the power station class contributes fairly to the peak day cost of gas allocation.

4.0 PROPOSED RATES AND CUSTOMER IMPACTS UPDATE

The following figures summarize the annual bill impacts, in both dollar and percentage terms, of the proposed November 1, 2019 sales rates that result from this update. The annual bill comparisons are relative to the May 1, 2019 rates approved in Order 47/19. Comparisons for the T-service customers reflect the delivery service only. The impact resulting from changes to the Primary Gas overhead component has not been reflected in the bill impacts shown in the figures below or in Schedule 11.1.0 (Update). Rather, this impact will be incorporated in the November 1, 2019 Primary Gas Rate Application.

The annualized bill impact resulting from base rate changes proposed for November 1, 2019 for the typical residential customer is a decrease of approximately 5.4% or $37 per year compared to May 1, 2019 base rates. The change in the billed rates results in a decrease for the typical residential customer of approximately 10.1% or $70 per year compared to May 1, 2019 billed rates. Please refer to the Schedule 11.1.0 (Update) for details of the annual bill impacts.

Figure 4.1 below shows the annual impacts, by sales service customer class, of the change in base rates proposed in this update compared to May 1, 2019 rates (see Schedule 11.1.0 (update), page 2).

Figure 4.1: Annual Bill Impacts of the Proposed Base Rates for Sales Service Customers by Customer Class

2019/20 Test Year			Annual Impacts Base Rates	
Customer Class	Consumption (10^3M^3)	Load Factor	$ Impact	% Change
SGS	1.0		($17)	-4.2%
	2.2		($37)	-5.4%
	11.3		($188)	-6.7%
LGS	11.3		($13)	-0.5%
	679.9		($803)	-0.7%
HVF	6,200	40%	($26,988)	-2.7%
	685	75%	($3,659)	-3.4%
Mainline	41,000	75%	($333,675)	-6.2%
	2,833	40%	($46,725)	-9.9%
Interruptible	850	25%	($4,106)	-3.1%
	14,164	75%	($77,065)	-4.4%

Figure 4.2 below shows the annual bill impacts for Transportation Service ("T-Service") customers in each of the customer classes for the change in base rates proposed in this Pre-Hearing Update, compared to the May 1, 2019 rates (see Schedule 11.1.0, page 2).

Figure 4.2: Annual Bill Impacts of the Proposed Base Rates for T-Service Customers by Customer Class

2019/20 Test Year			Annual Impacts Base Rates	
Customer Class	Consumption (10^3M^3)	Load Factor	$ Impact	% Change
HVF (T-Service)	2,600	75%	$10,269	20.8%
	17,600	75%	$75,127	29.2%
Mainline (T-Service)	14,000	75%	$36,225	25.5%
	44,000	40%	$272,558	41.8%
Special Contract	[redacted]			
Power Stations	[redacted]			

2d

The annual bill impacts of the proposed billed rates for the sales service customer classes are summarized in Figure 9 below (the details of which are provided on page 1 of Schedule 11.1.0).

Figure 4.3: Annual Bill Impacts of the Proposed Billed Rates for Sales Service Customers by Customer Class

2019/20 Test Year			Annual Impacts Billed Rates	
Customer Class	Consumption (10^3M^3)	Load Factor	$ Impact	% Change
SGS	1.0		($32)	-7.8%
	2.2		($70)	-10.1%
	11.3		($359)	-12.5%
LGS	11.3		($153)	-5.1%
	679.9		($9,204)	-7.3%
HVF	850	25%	($14,070)	-8.2%
	12,600	75%	($436,617)	-23.7%
Mainline	41,000	75%	($890,332)	-15.9%
	2,833	40%	($114,788)	-23.4%
Interruptible	850	25%	($10,862)	-7.8%
	14,164	75%	($331,435)	-17.9%

Figure 4.4 below summarizes annual bill impacts of the proposed billed rates for the T-Service customer classes (the details of which are provided on page 1 of Schedule 11.1.0).

Figure 4.4: Annual Bill Impacts of the Proposed Billed Rates for T-Service Customers by Customer Class

2019/20 Test Year			Annual Impacts Billed Rates	
Customer Class	Consumption (10^3M^3)	Load Factor	$ Impact	% Change
HVF (T-Service)	2,600	75%	$10,581	21.4%
	17,600	75%	$77,239	30.0%
Mainline (T-Service)	14,000	75%	$24,372	17.1%
	44,000	40%	$236,017	36.2%
Special Contract	[redacted]			
Power Stations				

2d

The billed rate impact for the Special Contract class is driven primarily by the allocation of the heating value deferral account balance. As noted above, Centra has continued to allocate the Heating Value Deferral Account on a volumetric basis based on the existing PUB-approved Cost of Service Study, and consistent with previously filed Application materials. As indicated by the PUB in Order 98/19, bill impact mitigation options, including the disposition of the Heating Value Deferral Account, will be reviewed at the oral evidentiary portion of the hearing to be held in August.