REFERENCE:

Application pp.13-14 of 40

PREAMBLE TO IR (IF ANY):

Centra states: "Transmission plant is defined as pipelines with operating pressures above 1900 kPa and associated transmission pressure pipeline valves and fittings, and all pressure reducing stations with direct interconnection to the TCPL Mainline.

Distribution Plant is defined as pipelines with operating pressures less than or equal to 1900 kPa and includes all pressure reducing stations downstream of transmission station plant, all farm taps and farm tap inlet piping and all associated pipeline valves, fittings, service lines and customer meter set assemblies."

QUESTION:

Please confirm whether Centra has any primary gate stations (connected to the TCPL Mainline) that step down the pressure to less than or equal to 1900 kPa. If confirmed, explain whether the cost of service study functionalizes the cost of these pressure reducing assets within the primary gate stations as Distribution. If not confirmed, explain why not.

RESPONSE:

Centra has six primary stations that reduce the pressure to less than or equal to 1900 kPa.
These six primary stations are classed as Transmission plant as indicated in the definition shown above and specifically "all pressure reducing stations with direct interconnection to the TCPL Mainline". While these six primary stations have lower outlet pressures than the remaining primary stations connected to the TCPL mainline, Centra's accounting records categorize these stations as transmission since they have many common features to the other primary stations on the TCPL mainline such as:

- TCPL Mainline inlet pressures. This requires the station pressure design to be suitable for the inlet pressure. From this perspective, there is generally no difference in the piping design or general components for a station with an outlet pressure above or below 1900 kPa;
- Custody transfer flow metering;
- Odourization capabilities including odourant storage and injection; and
- Instrumentation and SCADA communications to monitor the flow metering, odourization and station pressures.

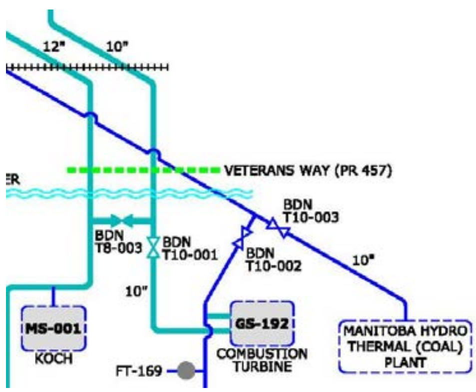
Centra's functionalization of these assets is based on the accounting records and as such they have been included in the Transmission Function.

REFERENCE:

Appendix 1 Atrium Report p. A-9

PREAMBLE TO IR (IF ANY):

From the available Centra Gas Pipeline Schematics referenced in Atrium's report, GS-192 appears to be fed by two sources of natural gas. Namely, from a 10-inch pipeline carrying unodourized gas between valve BDN T10-002 and GS-192, as well as from a 10-inch pipeline carrying odourized gas between valve BDN T10-002 and GS-192 (although the schematic provided shows two unodourized gas supply lines connecting to GS-192).



QUESTION:

Please explain whether the Power Station customer can use odourized gas from the 10-inch odourized pipeline to fuel the combustion turbines and whether there are any limitations to the operation of the generating station or to Centra's transmission system with using this source if the 10-inch unodourized line is out of service.

RESPONSE:

The schematic correctly shows a connection from the 10” odourized line to GS-192 but does not include the detail of the size of the connection.

The connection is a 2” commissioning line and would not permit the odourized gas line to be used to fuel the combustion turbines. Furthermore, CTs are unable to use odourized gas as the sulfur in the odourant creates the potential for corrosion on the blades of the turbine.

REFERENCE:

Appendix 1 Atrium Report p. 22; Order 164/16 p. 85 of 116; PUB Report on Efficiency Manitoba's 2020/21 to 2022/23 Efficiency Plan p. 16 of 198; PUB/Atrium I-9

PREAMBLE TO IR (IF ANY):

Atrium Report p. 22: "DSM – Allocated to the customer classes based on the forecasted participation by customer class."

Order 164/16 (p. 85 of 116) regarding Manitoba Hydro's electric Cost of Service Study: "The Board finds that DSM costs should be functionalized as 100% Generation. DSM should be classified with the other Generation assets based on system load factor, and allocated on Winter Coincident Peak for the Demand portion and unweighted energy for the Energy portion. The Board finds that DSM is a Generation resource: it avoids Generation costs, rather than the costs of Transmission and Distribution. […] DSM programs may appear similar to customer service programs such that the costs should be allocated or assigned to individual customer classes on a cost causation basis. The Board finds that, because DSM is a system resource, assigning DSM costs to individual classes is not warranted."

In its Report on Efficiency Manitoba's 2020/21 to 2022/23 Efficiency Plan Submission, the PUB states: "In the Plan, Efficiency Manitoba has designed DSM initiatives for six customer segments – Residential, Residential Income Qualified, Indigenous, Commercial, Industrial, and Agricultural – which group customers by their characteristics and energy consumption patterns and are intended to be inclusive of all Manitobans."

QUESTION:

a) Please identify any changes in the functionalization, classification, or allocation of demand-side management ("DSM") costs since DSM was transitioned to Efficiency Manitoba.
b) Please explain whether it would be analogous to the Manitoba Hydro electric COSS methodology for Centra to treat DSM costs as a system resource.

c) Please explain how Centra would functionalize and classify the DSM costs if DSM costs were to be treated as a system resource.
d) Please explain the upsides and downsides of treating DSM costs as a system resource in the COSS.
e) If Efficiency Manitoba groups its programs as either Residential, Residential Income-Qualified, Indigenous, and Commercial, Industrial, & Agricultural customer segments (i.e. Efficiency Manitoba's program groupings don't directly relate to specific Centra customer classes), please explain how Centra reconciles and allocates these DSM costs to each Centra customer class.
f) Given Efficiency Manitoba's customer segments for its natural gas DSM program offerings, please explain whether Centra's allocation methodologies for DSM continue to remain relevant and what methodology change may be needed, either now or in the future.

RESPONSE:

a) There have been no changes to the functionalization, classification or allocation of DSM costs since DSM was transitioned to Efficiency Manitoba ("EM").

b) If Centra were to treat DSM as a system resource in its cost allocation study, that treatment would be consistent with Manitoba Hydro's treatment of DSM since PUB Order 164/16. However, the reasoning for treating gas DSM as a system resource is not analogous to Manitoba Hydro (electric operations) treatment of DSM costs. In order to evaluate differences in the treatment of DSM program costs for cost allocation and rate setting purposes between Centra (gas operations) and Manitoba Hydro (electric operations), it is helpful to recognize the differences in the benefits between a vertically integrated hydro-electric utility and a natural gas distribution utility.

   In addition to lowering participating customer's consumption volumes and bills, electric DSM also provides potential benefits as it allows for the deferral of high-cost new generation resources and frees up energy for an increase in extra-provincial sales revenues to assist in offsetting costs for domestic electric customers. For these reasons, it may be more appropriate to treat DSM costs as a system resource for a vertically integrated electric utility.

Natural gas DSM however, does not achieve the same benefits as electric DSM as there is no deferral of local energy production investment and no increase in off-system revenues to help offset total costs. As such, and differing from a vertically integrated electric utility, treating as a system resource may not be a rational basis on which to allocate natural gas DSM costs.

c) If Centra was directed to treat DSM as a system resource, the most appropriate treatment would be to functionalize the costs as Production, classify them as Energy and allocate them based on volumes.

d) Treating DSM costs as a system resource is appropriate for highly cost-effective DSM expenditures that not only provide direct benefits to the participating customer, but also provide a significant reduction in overall system costs. Gas DSM primarily provides economic benefits to the participating customer and only minimal incremental economic benefits to the system as a whole.

Allocating DSM costs as a system resource may increase controversy during the regulatory review of the EM plan as each customer class will share the cost of DSM for all other customer classes. Accordingly, intervenor groups will be inclined to scrutinize the economics of programs offered to other classes, which may result in a reduction in programs for hard-to-reach customers in the income qualified and Indigenous customer segments if this results in DSM programming being selected purely on an economic basis.

As an upside, treating DSM as a system resource is administratively simpler and even if it is not justified on the basis of cost causation, the approach achieves broad allocation of costs across all customer classes, which is consistent with socializing the cost of DSM on a policy basis to recognize the non-energy supplemental benefits such as GHG reduction and socio-economic benefits.

e) As part of the transition of responsibility for DSM from Manitoba Hydro to EM, EM committed to continue to provide the DSM costs grouped into the specific customer classes used by Centra. Centra is not aware of the process used by EM to reconcile and allocate the costs between EM's customer segments and Centra's customer class.

f) The difference in customer groupings as used by EM does not necessarily require a change to Centra's allocation of DSM so long as EM is able to meaningfully translate costs from EM's customer segment framework to Centra's customer class breakdown.

If circumstances change and EM is not able to provide an accurate restatement of the cost by customer class, then Centra may be required to reconsider its allocation options using the best available information. Similarly, if the reconciliation and allocation process becomes overly onerous for EM, then Centra may choose to reevaluate the methodology in the interest of administrative simplicity. Although this additional work would be performed by EM, not Centra, any additional administrative costs are still ultimately recovered from Centra's customers.

REFERENCE:

Reference: Application p.19 of 50

PREAMBLE TO IR (IF ANY):

Centra states: "The amount of $12.0 million that is allocated to Centra represents Centra's share of the total annual interest on the debt incurred by Manitoba Hydro to acquire Centra as well as the amortization of the related acquisition and integration costs incurred by Manitoba Hydro. These costs are functionalized, classified and allocated on the basis of Rate Base."

QUESTION:

Please explain and justify why Rate Base is an appropriate basis for functionalizing, classifying, and allocating the Corporate Allocation.

RESPONSE:

Functionalizing, classifying, and allocating the costs of Corporate Allocation according to rate base recognizes that the acquisition costs and associated interest expense are directly related to the acquired assets and effectively treats these costs as a return on investment. This treatment is consistent with the view expressed by the PUB in Order 135/05 (page 21); *"the Board considers the Corporate Allocation to be a form of return on shareholder investment, reducing the amount that otherwise may be allowed to Centra as net income."*

REFERENCE:

Application p.22 of 40

PREAMBLE TO IR (IF ANY):

Centra states: "The Peak and Average method considers two factors in the allocation of capacity costs to each respective customer class. As the title suggests, the class' contribution to the system peak day is one component, and the class' respective share of total annual system throughput is the other component. The system load factor is used to weight the average daily demand and "one minus the system load factor" is used to weight the system peak day demand. A Peak and Average allocator is calculated for each level of the system, with the weighting factors varying accordingly to reflect how customer classes use that level of the system."

QUESTION:

Please explain why system load factor is an appropriate way to determine the classification between demand and energy for the Peak and Average allocator.

RESPONSE:

The following explanation why system load factor is appropriate for determining the classification between demand and energy is quoted from page 15 of 22 of the evidence from R. J. Rudden and Associates on the "Cost of Service Review" dated May 31, 1996, that was filed as part of Centra's 1996 Application.

> *"Peak and Average: Each class' contribution to a weighted average of design day demand and average daily demand. This approach to allocation makes a recognition that average daily demand (commodity) plays some role in determining the level of demand-related costs. This proposition is not based on any engineering basis, but rather reflects an equity consideration that higher load factor customers use the capacity more heavily than lower load factor customers, and therefore should receive*

> *a greater share of its total cost. RJRA uses the system load factor to weight the average daily demand, and "one minus the system load factor" to weight the design day demand."*

Centra notes that the R. J. Rudden rationale still holds true today. The use of the load factor to determine the classification between demand and energy is premised on the NARUC Electric Utility Cost Allocation Manual which recognizes the use of system load factor in its *Average and Excess Allocation Methodology*, which is very similar to Centra's *Peak and Average Methodology*.

REFERENCE:

Application p.22 of 40; Appendix 1 Atrium Report Appendix A

PREAMBLE TO IR (IF ANY):

At Application p. 22 (lines 19-20), Centra states: “the Special Contract and Power Station classes are excluded from the allocator used for Town Border Stations”

Main Line class customers – such as McCain Foods in Carberry (as shown in Atrium Appendix A p.A-11), Husky in Minnedosa (Atrium Appendix A p. A-19), and Simplot in Portage La Prairie (Atrium Appendix A p. A-24) – are served directly from transmission lines from primary gate stations which do not pass through town border stations. The Special Contract and Power Station customers appear to be served from transmission facilities that pass through town border stations (Atrium Appendix p.A-9).

QUESTION:

Please provide further explanation for why Special Contract and Power Station classes are not allocated town border station costs while the Main Line class is, considering some Main Line customers do not make use of town border station facilities.

RESPONSE:

Centra’s statement that Special Contract and Power Station classes are excluded from the allocator used for Town Border Stations is in reference to the fact that those classes are not factored into the allocator PAVG-TBS which is used for Distribution Measuring and Regulating Equipment (477), Distribution Regulating Equipment and Structures & Improvements M&R (472.1), and Telemetry (477.1). The Distribution Measuring and Regulating Equipment includes the costs of all regulating stations, with the exception of the primary gate stations with direct interconnection to TCPL. While excluded from the PAVG-TBS allocator, the Special Contract and Power Stations classes are directly assigned the cost of their dedicated measuring and regulating equipment included in account 477 using the

DISTM&R allocator. The DISTM&R allocator functionalizes the dedicated costs as onsite and directly assigns them to the Special Contract and Power Stations classes; the remaining balance in account 477 is then allocated to the rest of the customer classes using the PAVG-TBS allocator.

This treatment of direct assignment of onsite costs to the Power Station and Special Contract customer is longstanding, does not represent a change in methodology, and is consistent in both Centra's approved and proposed methodology. The Mainline class is allocated the costs of these facilities as their dedicated regulating stations are included in Distribution M&R.

REFERENCE:

Application Figure 9 pp. 23 and 24 of 40

PREAMBLE TO IR (IF ANY):

Figure 9 states:
"Customer & Public Relations: Customer & Public Relations costs are allocated based on a composite allocation factor derived from customer numbers weighted differently for the specific expense categories

Customer Safety: Customer Safety costs are allocated based on a composite allocation factor derived from customer numbers weighted differently for the specific expense categories (Safety Watching, Odor related calls, Customers education & safety)

Customer Inspection: A portion of Customer Inspection costs functionalized to Onsite and classified as customer-related are allocated based on customer numbers: the customer equipment problem program is allocated to SGS customers, equipment inspection is allocated to all customers based on the number of customers in each class"

QUESTION:

a) Please show the derivations of the composite allocation factors for Customer & Public Relations and Customer Safety.
b) Inspections of commercial and industrial appliances are more complex, time-consuming, and therefore incur greater costs. Please confirm whether Centra weights the number of customers when allocating equipment inspections. If not confirmed, explain why unweighted customers is the appropriate allocator.

RESPONSE:

a) Please see Attachment 1 to this response.

b) Not confirmed. Centra uses unweighted customer count to allocate the Customer Inspections program costs. This program includes costs associated with the following: customer's equipment problem, maintenance of conversion burners and the response to requests for locations of buried natural gas lines. Costs associated with conversions burners are allocated only to Small General Service class and the rest of the costs are allocated based on the unweighted customer number. Centra views the current allocation method as reasonable.

Centra Gas Manitoba Inc.
Costs of Service Methodology Review

Summary of derivation of the composite allocation factor for Customer & Public Relations costs

		SGS-R	SGS-C	LGS	HVF	Co-op	ML	SC	PS	INT	FRPGS	Total
Customer/Consumer consultation (Customer Eng Service)	Customers Number[2]	[redacted]										288,566
	Weighting (%)	34%	33%		33%							100%
	Allocation ($)	18,422	12,401	5,479	13,754	125	1,125	125	250	2,501		54,183
Customer/Consumer consultation (Major&Key Accounts))	Customers Number	[redacted]										
	Allocation (%)				77%		6%	1%	1%	14%		100%
	Allocation ($)				362,999		29,700	3,300	6,600	66,000		468,598
Customer/Consumer consultation (Energy Service & Sales)	Customers Number	[redacted]										
	Weighting (%)	50%		50%								100%
	Allocation ($)	413,602		413,602								827,205
Customer/Consumer consultation (CSO)	Customers Number	[redacted]										288,566
	Allocation (%)											100%
	Allocation ($)											836,254
Customer/Consumer consultation (Contact Center)	Weighting (%)	85%	10%	5%								100%
	Allocation ($)	442,467	52,055	26,027								520,549
Donations/grants/sponsorships	Customers Number	[redacted]										
	Allocation (%)											100%
	Allocation ($)											129,758
Gas system expansion initiatives (Customer Policies & Gas Expa	Customers Number	[redacted]										288,566
	Weighting (%)	70%		20%	10%							100%
	Allocation ($)	371,606	26,122	113,637	43,706	397	3,576	397	795	7,947		568,183
Gas system expansion initiatives (Customer Policies & Gas Expa	Customers Number	[redacted]										288,566
	Weighting (%)	55%		40%	5%							100%
	Allocation ($)	63,339	4,452	49,303	4,741	43	388	43	86	862		123,257
Gas system expansion initiatives (Customer Policies & Gas Expa	Customers Number	[redacted]										288,566
	Weighting (%)	30%		65%	5%							100%
	Allocation ($)	6,453	454	14,965	886	8	72	8	16	161		23,023
Marketing Programs (Business Communications)	Customers Number	[redacted]										
	Allocation (%)											100%
	Allocation ($)											105,329
Marketing Programs (Marketing Services)	Customers Number	[redacted]										
	Allocation (%)	93%	7%									100%
	Allocation ($)	283,239	19,911								21,327 [1)]	324,477
Market Forecast (Market Forecast & Load Research)	Customers Number	[redacted]										288,566
	Weighting (%)	50%		25%	25%							100%
	Allocation ($)	12,063	848	6,455	4,966	45	406	45	90	903		25,822
Public/community/municipal relations	Customers Number	[redacted]										
	Allocation (%)											100%
	Allocation ($)											1,916
Customer & Public relations	Total ($)	**2,585,303**	**184,720**	**659,724**	**431,370**	**622**	**35,294**	**3,922**	**7,843**	**78,431**	**21,327**	4,008,554
CUSTREL	Allocation (%)	**64.5%**	**4.6%**	**16.5%**	**10.8%**	**0.02%**	**0.9%**	**0.1%**	**0.2%**	**2.0%**	**0.5%**	100%

1e

1) Marketing Costs related to FRPGS directly allocated to this program

2) Customers Number from 2017 Load Forecast (original application 2019/20 GRA)

Centra Gas Manitoba Inc.
2021 Costs of Service Methodology Review

Summary of derivation of the composite allocation factor for Customer Safety costs

			SGS-R	SGS-C	LGS	HVF	Co-op	ML	SC	PS	INT	Total
1			SGS-R	SGS-C	LGS	HVF	Co-op	ML	SC	PS	INT	Total
2												
3	Customer Safety Services (Odor related calls)	Customers Number[1)]	[redacted]									
4		Weighting (%)	65%									65%
5		Weighting (%)			35%							35%
6		Allocation ($)	600,851	42,061	369,714	4,939	44	400	44	89	890	1,019,033
7												
8												
9	Customer Safety Services (Consumer education & safety)	Customers Number	[redacted]									
10		Allocation (%)	[redacted]									100%
11		Allocation ($)										177,338
12												
13												
14	Customer Safety Services (Safety watching)	Customers Number	[redacted]									
15		Allocation (%)	[redacted]									91%
16		Allocation ($)										275,958
17												
18	Customer Safety	**Total ($)**	**1,012,127**	**70,852**	**382,807**	**5,045**	**45**	**409**	**45**	**91**	**909**	**1,472,330**
19	CUSTSAFE	**Allocation (%)**	**68.7%**	**4.8%**	**26.0%**	**0.3%**	**0.0%**	**0.03%**	**0.00%**	**0.01%**	**0.1%**	**100%**
20												
21												

22 [1)] Customers Number from 2018 Load Forecast (Supplement 2019/20 GRA)

1e

REFERENCE:

Application pp. 22, 29-30, and 34-35 of 40; Appendix 1 Atrium Report pp. 24-25 and B-1; 2019/20 Centra GRA IR IGU/Centra I-13c

PREAMBLE TO IR (IF ANY):

Application p. 22: "A Peak and Average allocator is calculated for each level of the system, with the weighting factors varying accordingly to reflect how customer classes use that level of the system.

Appendix 1 (Atrium Report) pp. 24-25: "In place of the aforementioned analysis, as an alternative approach for storage and related pipeline injection and redelivery capacity, Centra should use the winter season demand in excess of summer season demand. Winter season throughput would be an alternative allocation method for Supplemental Supply. An alternative allocation method for year-round pipeline capacity should be peak day demand, at the design day level. For interruptible customers, Centra should consider the use of a 100% load factor contribution to the peak day allocator. This will prevent these customers from escaping some peak day responsibility; that is, if Centra's capacity resources can accommodate the cumulative design day peak demands of the interruptible customer group."

QUESTION:

a) Please file Centra's calculation for the Peak and Average allocator from IGU/Centra I-13c from the 2019/20 Centra GRA.
b) Please provide a non-confidential narrative description of the calculation for the proposed Coincident Peak Demand allocation.
c) Please provide the calculation for the proposed Coincident Peak Demand allocator used to generate the illustrative COSS results of Appendix 4.
d) Please provide a non-confidential narrative description of the calculation for the alternate "winter season demand in excess of summer season demand" allocation methodology for storage and related pipeline capacity.

e) Please provide the calculation for the proposed "winter season demand in excess of summer season demand" allocator for storage and related pipeline capacity allocator used to generate the illustrative COSS results of Appendix 4.

RESPONSE:

a) Please see Attachment 1 to this response.

b) Centra's coincident peak-day is defined as the highest total daily volume for the fiscal year, measured at the points where Centra receives the natural gas from the TCPL pipeline. The coincident peak-day contribution for each customer class is recorded for the Top Consumer (HVF, INT, MLF) and Special (PS, SPEC) rate classes. The Small General Service (SGS) Residential, SGS Commercial and Large General Service (LGS) contributions equal the difference between the system and the customer classes that are recorded.

The coincident peak day forecast is based on average of three years of metered historical heat value adjusted coincident peak day volume, collected for the entire Centra system. As Top Consumers and Special rate classes have daily metered volume recorded, the remaining volume is attributable to the SGS Residential, SGS Commercial and LGS classes where daily volume information is not available. The coincident peak day forecast for each of the three remaining sectors is estimated by utilizing the weather coefficients for each sector.

To develop the Coincident Peak allocator Centra compares each class's peak day demand to the total system peak demand in order to determine each class's proportionate contribution to system peak.

c) Please see Attachment 2 to this response.

d) Winter season demand in excess of summer season demand is a relative comparison of class contribution to the total winter excess demand where winter excess is calculated as the average winter load less the average summer load. For Centra that equates to the average monthly throughput for November through March (winter) minus the average monthly throughput for April through October (summer). Each customer class's winter excess is then compared to the total winter excess to derive the customer class share.

e) Please see Attachment 3 to this response.

Centra Gas Manitoba Inc.
2019/20 General Rate Application
PAVG & PAVG-T Allocation Factors

IGU/CGM I - 13 c)
Attachment

			Total	SGS-R	SGS-C	LGS	HVF	CO-OP	ML	SC	GS	INT	
	PAVG (peak & average excluding T-Service)												
	PAVG (peak & average excluding T-Service												
1	Volumes	10^3M^3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]	
2	% of Total Volumes			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1d
3													
4	Coincident Peak-Day	10^3M^3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
5	% of Total Coincident Peak			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
6													
7	System Load Factor		[redacted]										
8	1 - System Load Factor		[redacted]										
9	Note: System load factor = total volumes/365/coincident peak day ([redacted]												
10													
11	% of Total Volumes			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
12	System Load Factor			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
13	Average Component			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
14													
15	% of Total Coincident Peak			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
16	1 - System Load Factor			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
17	Peak Component			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
18													
19	PAVG allocator (row 13 + row 17)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
20													
21													
22	**PAVG-T (peak & average including T-Service)**												
23	Volumes	10^3M^3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
24	% of Total Volumes			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1d
25													
26	Coincident Peak-Day	10^3M^3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
27	% of Total Coincident Peak			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
28													
29	System Load Factor		[redacted]										
30	1 - System Load Factor		[redacted]										
31	Note: System load factor = total volumes/365/coincident peak day ([redacted]												
32													
33	% of Total Volumes			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
34	System Load Factor			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
35	Average Component			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
36													
37	% of Total Coincident Peak			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
38	1 - System Load Factor			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
39	Peak Component			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
40													
41	PAVG allocator (row 35 + row 39)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

Centra Gas Manitoba Inc.
2021 Cost of Service Methodology Review

Calculation of Coincident Peak Demand Allocator

		Residential SGS-R	Small Commercial SGS-C	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Interruptible INT	Special Contracts SC	Power Stations PS	Total	
1	**2019/20 Coincident Peak Day Forecast**											
2												
3	Peak Forecast by class											
4	(10^3m^3)											
5												
6												
7	System Supply	[redacted]										
8	Fixed Rate Offering											
9	WTS											1d
10	T-Service											
11	**Total**											
12												
13	Calculation of Coincident Peak Demand Allocator											
14												
15		[redacted]										
16	**PDAY** (10^3m^3)											
17	(%)											
18												
19	**PDAY - T** (10^3m^3)											
20	(%)											
21												
22	**PDAY (DA)** (10^3m^3)											
23	(%)											
24												1d
25	**PDAY - TBS** (10^3m^3)											
26	(%)											
27												
28	**PDAY - D** (10^3m^3)											
29	(%)											
30												
31	**PDAY - INT** (10^3m^3)											
32	(%)											

Centra Gas Manitoba Inc.
2021 Cost of Service Methodology Review

Calculation of Winter Excess Allocator

		Residential	Small Commercial	Large Gen Service	High Volume	Cooperative	Main Line	Interruptible	Total	
1	Monthly volumes by class									
2	(10^3m^3)									
3		SGS-R	SGS-C	LGS	HVF	CO-OP	ML	INT	Total	
4										
5	Apr	[redacted]								
6	May									
7	June									
8	July									
9	Sep									
10	Sept									1d
11	Oct									
12	Nov									
13	Dec									
14	Jan									
15	Feb									
16	Mar									
17	Total									
18										
19	Calculation of Winter Excess Allocator									
20										
21	Winter Average (Nov to Mar)	[redacted]								
22	Summer Average (Apr to Oct)									1d
23										
24	**Winter Excess Allocator** **(10^3m^3)**									
25	*(row 21 less row 22)* **(%)**									

REFERENCE:

Application pp. 30-31 of 40; Appendix 1 Atrium Report pp. 24-25 (section 6.4.1)

PREAMBLE TO IR (IF ANY):

Application p. 30-31: "To reliably meet the requirements of all customers, the transmission and distribution system must be able to supply the peak demand on the system. Design Day corresponds to the day with the highest coincident system peak conditions that the system is designed to meet under extreme weather conditions. As Centra uses a peak design hour approach for planning purposes, a Design Day metric by customer class is currently not available. As this metric will take time to develop, the illustrative impacts of the recommendations in Appendix 4 utilize the current peak day definition, as developed for the purposes of the Peak and Average allocator which by contrast assumes an average winter and is based on three years of historical data."

QUESTION:

a) Please provide an expected timeline for the availability of a Design Day metric (as proposed by Atrium) and describe Centra's anticipated implementation plans of this new metric in future Cost of Service Studies. Is Centra committing to developing this metric in a timely fashion (e.g. filed as part of Centra's next GRA)?
b) Please explain in more detail the process for determining the class peaks based on the three years of historical data.
c) Please explain how seasonal loads (such as asphalt plants and grain dryers) are treated when developing the Peak and Average allocator and how such loads are proposed to be treated under the Coincident Peak allocator.
d) Please explain whether a peak design hour allocator can be used or developed. Provide the pros and cons of using peak design hour in the allocation of demand costs.
e) Please explain whether contract demand for larger volume customers can be used in the calculation of the Coincident Peak or Peak and Average allocators in place of historical demand data.

RESPONSE:

a) Centra would like to clarify the statement included in the preamble "As Centra uses a peak design hour approach for planning purposes, a Design Day metric by customer class is not available". The statement implies that the development of the two metrics are inextricably correlated; however, that is not the case. In reviewing how class contribution to Design Day could be developed, Centra has determined that it will follow a process similar to the existing peak day methodology that is described in PUB-Centra I-8b, where the hourly information will be used to tabulate gas daily information for all complex gas customers (HVF, MLF, INT, SPEC-T, PS) and remaining classes together (SGS Residential, SGS Commercial, LGS). A weather normalization model would be created leveraging the previous 3 years of historical data and used to develop the approximate class contribution to a design day temperature rather than an expected peak day. To quantify the class contribution of the SGS Residential, SGS Commercial & LGS, monthly billing information would be leveraged in a weather normalization model to calculate individual class contribution.

   Centra commits to having the design day metric by customer class prior the next GRA.

b) Please see the response to PUB/CENTRA I-8 b) and c).

c) Seasonal loads are not explicitly considered in the development of either the Peak and Average allocator or the proposed Coincident Peak allocator. To the extent that seasonal loads do not contribute to the historical coincident peak demand of their class, their load is effectively not included in the determination of their class' coincident peak demand. In the calculation of the Peak and Average allocator their demand would be similarly excluded from "peak" but their annual volumes would be included in the "average".

d) The Design Day approach described in part a) will be developed in conjunction with the approved load forecast for the test year and will ensure consistent assumptions by class across all allocators. Design Hour is a planning tool used in the hydraulic modelling done by the Gas Engineering & Construction Group and while it is possible to use the data to develop a Design Hour by class, it will necessitate the data be reconciled to the forecast volumes assumed in the test year. Centra sees no apparent advantages to cost allocation from using a Design Hour allocator that would warrant the additional process required to develop it. Furthermore, as Centra plans its upstream capacity with consideration to the Design Day, in Centra's view a Design Day allocator is the preferred and more appropriate allocator.

e) Contract demand for large volume customers cannot be used in the calculation of peak allocators as not all contracts accurately reflect current customer demand. History has shown that contract amounts are not always indicative of the demands a customer will place on the system and this is even more prevalent when a customer's billed demand is not tied to their contract level as they may tend to overestimate their needs.

REFERENCE:

Application pp. 30-31 of 40; Appendix 1 Atrium pp. 24-25 (section 6.4.1)

PREAMBLE TO IR (IF ANY):

Centra states: "With the evolution of Centra's system and the Interruptible Class, there are allocation methods other than Peak and Average that can be used while still ensuring cost recovery from all users of the system. The Interruptible Class can be included in the calculation of the Coincident Peak allocator for two reasons. First, the Interruptible Customers use Centra's distribution system to receive Alternate Supply[4] even while being curtailed for upstream capacity factors. Second, Centra includes the Interruptible Class capacity requirements in its downstream capacity planning criteria. This ensures all customers that use the system pay for a portion of the system and is more closely aligned with cost causation than a Peak and Average allocator."

QUESTION:

a) Please confirm whether Interruptible class customers have the right to switch to firm service following appropriate notice to Centra.
b) In the past twenty years, please confirm whether Interruptible class customers have been curtailed due to restrictions on available capacity on Centra's system while firm customers continued their service. In responding to this information request, exclude any curtailments due to upstream capacity limitations, line damages, or repairs to the specific customer service lines. If confirmed, provide details of the events that led to the curtailments.

RESPONSE:

a) Confirmed. Written requests for transfer from Interruptible to Firm service must be made no later than March 15th of each year, followed by the Customer and Centra executing a service agreement by no later than June 30th and the service transfer becoming effective by November 1st of that same year.

b) Centra's Interruptible customers have not been curtailed for downstream-related reasons over the past 20 years.

REFERENCE:

Application p. 32 of 40

PREAMBLE TO IR (IF ANY):

"Additionally, the pipelines that serve this [Special Contract] customer class predominantly have a one-way relationship with the rest of the system. This is to say that the remainder of the transmission system can receive pressure and capacity support from the pipelines that serve the Special Contract Class, but the rest of the Brandon system, with the exception of the facilities serving the Brandon Power Station, cannot generally be used to serve the load requirements of the Special Contract Class."

QUESTION:

a) Please confirm whether the presence of a gas odourant is the main driver behind Centra's statement that "the rest of the Brandon system, with the exception of the facilities serving the Brandon Power Station, cannot generally be used to serve the load requirements of the Special Contract Class."
b) Please confirm whether the Special Contract and Power Station classes make use of the assets in the primary gate stations, such as pressure regulation. Explain whether these classes have any responsibility for primary station costs.
c) Please confirm whether the proposed direct assignment takes into consideration any assets in primary gate stations utilized by Special Contract and Power Station classes

RESPONSE:

a) Confirmed. The sulphur contained in the odourant is considered a contaminant to the process used by the Special Contract Class that will result in equipment damage.

Response to parts b) & c):

Under Centra's approved methodology, the Special Contract and the Power Station classes are allocated costs related to all primary gate stations based on the peak and average allocator. These two classes do not make use of pressure regulation or odourization assets contained in primary stations. Under Centra's proposed direct assignment approach, the Special Contract and Power Station classes will be responsible for costs related to flow meters and meter isolation valves, pipes and fittings located in the Brandon Primary Station.

REFERENCE:

Application p. 33 of 40, Appendix 1 Atrium Report pp. A-15 and A-37.

PREAMBLE TO IR (IF ANY):

"Centra notes that the Selkirk Power Station is no longer part of the transmission grid and the assets associated with generating power were retired on March 31, 2021 and will be physically decommissioned once a decommissioning plan is established and approved."

QUESTION:

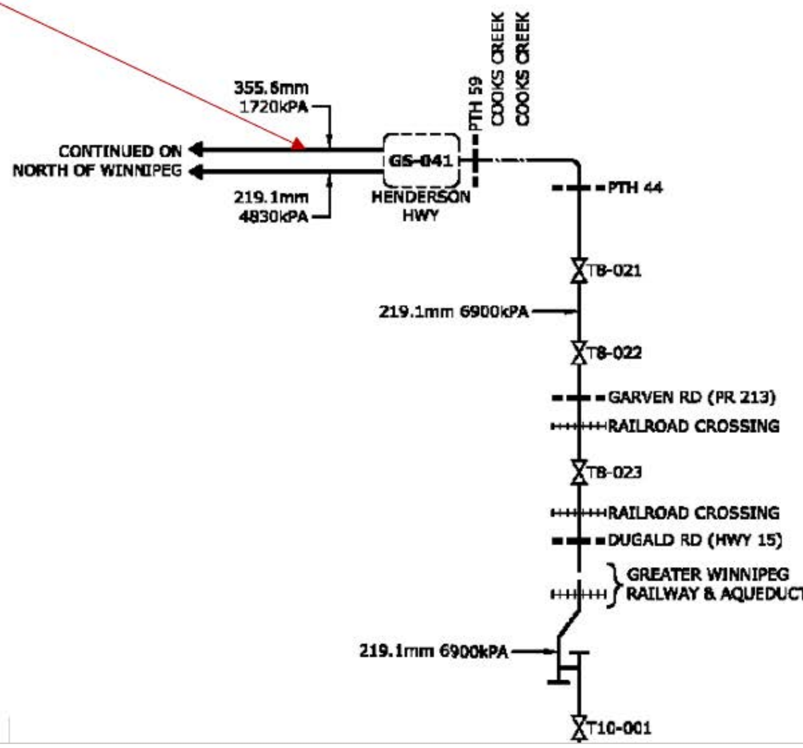
a) Please explain whether any decommissioning costs associated with the gas supply assets serving the Selkirk Power Station will be directly assigned to the Power Station class or whether such costs (or a portion thereof) may be borne by other Centra customer classes.
b) In the schematics shown in Atrium's Report Appendix A pages A-15 and A- 37, please show which, if any, gas assets will be decommissioned as a result of decommissioning the Selkirk generating station.

RESPONSE:

a) No, they will not be directly assigned to the Power Station class and will not be borne by other Centra customer classes.

b) Based on the schematic on page A-15 from Appendix 1 of the Atrium Report the following identifies the line that will be decommissioned.

The pipeline from GS-041 (355.6 mm, 1720 kPA) is line that has been detached with the decommissioning of the Selkirk G.S. The remaining lines and Gate Stations will be re-assigned to support the Tyndall and Oakbank areas system supply



REFERENCE:

Application p. 33 of 40; PUB MFR 5 (2021 COSMR Application); Order 79/98 p. 124; Appendix 3 pp. 2 and 27-32

PREAMBLE TO IR (IF ANY):

"Centra also notes that any implementation of this recommendation also needs to consider the "franchise expansion adjustment" which has been in place since the 2003/04 GRA and is intended to mitigate rate impacts related to expansion projects that occurred in the mid-1990s. Based on the method described in PUB MFR 5, customers whose rates are predominantly transmission-based have their Revenue Requirement reduced by the adjustment."

Page 124 of Order 79/98 states: "Centra also proposed to reclassify the unamortized balance of all contributions in aid of construction as being totally transmission related, rather than pro-rating these contributions according to the amount of capital expenditures for each category, as it had previously done. Centra proposed this change as an interim measure to address the negative impacts of rural expansion costs on the Special Contract and Mainline Classes. These customers do not pay any distribution costs and hence a large investment in transmission costs, as has been and will be the case for expansion in rural areas of Manitoba, will result in more costs being allocated to them. These customers submit that, as they receive no benefit from these expansion projects, nor are there any Mainline or Special Contract customers in these rural areas, they should not bear any of these transmission costs. Centra originally estimated that the SGS customer class would be allocated an additional $639,000 because of this change and all other customer classes would have less costs allocated to them as a result."

QUESTION:

a) Please provide a description of the franchise expansion adjustment, its origin and purposes, and how the mitigation adjustment was determined and applied.

b) Please explain whether the proposed end to the franchise expansion adjustment applies to all customer classes, just to the Special Contract and Power Station classes, or to other classes with predominantly transmission- allocated costs, such as the Main Line class.
c) The CIAC functional allocator shown in Appendix 3 at pages 27 to 32 shows contributions in aid of construction being allocated using TRANDEPEXP, DISTDEPEXP, and CUST-SGS allocators. Please explain whether and how the franchise expansion adjustment applies to these allocators.
d) Provide a table showing the calculation of the CIAC allocator and identify the franchise expansion adjustment.

RESPONSE:

a) Please see an excerpt of the discussion from Centra's 2003/04 General Rate Application, included in Attachment 1 to this response, that describes the purpose and derivation of the Franchise Expansion Adjustment.

b) Centra's proposal is to eliminate the franchise expansion adjustment for all classes, should the recommendation to use a Direct Assignment, and the recommendation to move to a Coincident Peak allocator in lieu of Peak and Average be approved.

Response to parts c) and d):

The contributions in aid of construction are functionalized (CIAC) to transmission (77%), distribution (16%) and onsite (7%). The transmission and distribution portions are allocated in proportion to depreciation expense in each functional classification (TRANDEPEXP, DISTDEPEXP). The onsite portion is allocated to SGS customers (CUST-SGS). The franchise expansion adjustments are directly allocated to customer classes through (EXFRAN) allocator, and the results are combined with contributions in aid of construction being allocated using TRANDEPEXP-D allocator. Attachment 2 to this response provides the allocation of amortization of contributions in aid of construction and identifies the franchise expansion adjustment.

costs has changed. In particular, gas accounting costs are now allocated to all upstream services in proportion to gas costs. Previously, gas accounting costs were assigned to Storage and Pipeline functions and allocated using the peak and average allocator.

11.3.2 Expansion Cost Allocation

Centra engaged in several sizable ex-franchise ("expansion") projects between 1995 and 2000 that had been an issue for cost allocation for the 1997 GRA, the 1998 GRA and the 1999 Cost of Gas Application. The issues were resolved through a joint proposal by Centra and the Special Contract Customer that was approved by the PUB in the 1999 Cost of Gas hearing in Order 118/99. In that Order, Centra was directed to implement that proposal in its next GRA. The change in Cost Allocation Methodology discussed here implements the approved modification.

Centra embarked on its 1995/96 Infrastructure Project in the mid 1990s, with approval of the PUB and support of local, provincial and federal governments. Placing the project in service in 1997 created an unanticipated rate impact on non-participating customers. The Special Contract Customer in particular objected to the results of the conventional Cost Allocation Methodology. Under the conventional methodology, the costs of expansion projects are borne by all customers, while revenues from participating customers are only credited to their particular rate classes (SGS and LGS). As well, where expansion projects involve a large investment in transmission plant, the rates for large customers, such as the Special Contract Customer, may increase under the conventional Cost Allocation Methodology because the rates for these large customers are predominantly transmission cost based.

In the 1998 GRA, Centra proposed an alternative Cost Allocation Methodology that attempted to mitigate the impact of expansions on those customers whose rates are predominantly transmission cost based. In its proposal, all of the Contribution in Aid of Construction ("CIAC") obtained by Centra for these expansions were functionalized to the Transmission function. Since customer contributions represent interest-free financing, they reduce financing and depreciation costs of the function and rate class they are assigned to. The proposed 1998 treatment was unacceptable to the intervenors, so the PUB directed Centra to develop a new recommendation in cooperation with the Special Contract Customer.

The joint methodology that was presented and approved in the 1999 Cost of Gas Application was designed to keep non-participating customers from financially supporting any negative cost impacts of expansion projects. The approach had three key features:

- Removal of all costs, revenues and loads associated with ex-franchise projects to determine rates that each class would have paid;
- Adjusting Cost Allocation Study results so that all classes pay the same rates they would have paid absent expansion projects; and
- If the revenues from expansion participants are inadequate to hold all other customers harmless, an accounting adjustment is made (accelerated amortization of CIAC) to make up the difference.

Six projects were evaluated in the 1999 proposal: 1995/96 Infrastructure Project; Central Hanover/LaBroquerie; Interlake; East Portage; Tache; and Ste. Anne. Of the six projects, East Portage proved to have insignificant dollar expenditures, and Tache and Ste. Anne were never constructed. The investment and contribution for each of the significant projects are shown in the table below.

Investment and Construction Summary of the Expansion Projects

	1995/96 Infrastructure	Central Hanover / LaBroquerie	Interlake	Total
Transmission Stations	$2,112,725	$672,099	$619,183	$3,404,007
Transmission Mains	$16,261,201	$2,203,768	$4,684,292	$23,149,261
Distribution Services	$2,371,715	$1,591,597	$249,302	$4,212,614
Distribution Mains	$4,487,800	$4,068,375	$942,005	$9,498,180
Total Investment	$25,233,441	$8,535,839	$6,494,782	$40,264,062
Customer Contribution	$19,807,545	$8,313,800	$6,210,735	$34,332,080

To adjust the Cost Allocation Study for the impacts of these projects, estimates were developed for depreciation and amortization expense, general taxes and finance costs associated with the projects. The accumulated reserve for depreciation and amortized contribution was also estimated to determine the rate base impact of these projects. Also, loads from participating customers in each project were identified, to determine the revenues generated, as well as allocations to be removed from the Cost Allocation Study.

Centra estimates that revenues associated with these expansion projects in 2003/04 will exceed their annual expenses by approximately $19,575, as shown on the table below.

The table allocates revenues and expenses of these projects by customer class.

Annual Revenue and Expense from Designated Expansion Projects

	Revenue (1)	Allocated Expense (2)	Allocated Excess Revenue (3)	Permanent Adjustment (1+2+3)
SGS-Res	674,808	(310,099)	(6,580)	358,129
SGS-Comm	311,150	(188,671)	(769)	121,710
Large General	409,484	(390,031)	(2,740)	16,713
High Volume	0	(55,072)	(546)	(55,618)
Co-op	0	(142)	(1)	(144)
Mainline	0	(35,510)	(167)	(35,677)
Special Contract	0	(258,851)	(110)	(258,961)
Power Stations	0	(122,646)	(65)	(122,711)
Interruptible	0	(23,179)	(263)	(23,442)
Primary Gas	0	7,799	(7,799)	0
Suppl. Firm	0	458	(458)	0
Suppl. INT	0	77	(77)	0
Total	1,395,441	(1,375,867)	19,575	0

However, revenues and expenses assigned to the individual rate classes using generally accepted cost allocation principles cause the costs (and therefore the rates) of non-participating customers to increase. The allocation of revenues and expenses are shown in the first two columns of the table. Column three allocates the excess revenues over costs of $19,575 to the various customer classes as shown. The last column identifies the permanent adjustment included in the 2003/04 Cost Allocation Study, and will be used in future cost allocation studies to adjust the class allocations resulting from expansion projects. Since the projects have now achieved a revenue-to-cost ratio that is greater than one, no acceleration of the amortization is required to hold customers harmless.

11.3.3 Creation of a Specific Rate Class for Co-ops

In the 2002/03 Cost of Gas Application, Centra proposed a specific rate to serve Cooperative Customers like the North Cypress Energy Co-op ("NCEC"). It was felt by NCEC that their circumstances were different enough from any existing rate class to warrant separate treatment. At the time, NCEC was served under the LGS class.

Centra created a new class for Cooperatives and has incorporated this class into the 2003/04 Cost Allocation Study. The following characteristics were used:

- NCEC's allocation of demand costs reflected the same treatment as the Mainline class, since NCEC is served from dedicated high pressure distribution facilities (that is, a specific Metering & Regulation ("M&R") facility, also referred to as a Town Border Station);
- NCEC's Onsite costs reflect $11,000 of investment in that M&R station;
- NCEC's demand rate reflects 100% of demand related costs, just as Mainline class rates; and
- NCEC's basic monthly charge reflects 100% of Onsite costs, just as Mainline class rates.

Centra Gas Manitoba Inc.
2021 Costs of Service Methodology Review

Allocation of Amortization of Cust. Contributions identifying the franchise expansion adjustment

Allocation Factor	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Total
CUST-SGS	-76,112	-5,328	-81,440	0	0	0	0	0	0	0	-81,440
TRANDEPEXP-E	-171	-32	-203	-145	-46	0	-39	-15	-29	-51	-528
TRANDEPEXP-D	-285,663	-54,581	-340,244	-260,505	-79,999	-128	-48,931	-128,626	-6,201	-8,213	-872,847
***EXFRAN** (table in part (a) to this response)*	***358,129***	***121,710***	***479,839***	***16,713***	***-55,618***	***-144***	***-35,677***	***-258,961***	***-122,711***	***-23,442***	***0***
Sub-Total	72,466	67,129	139,595	-243,792	-135,617	-271	-84,608	-387,587	-128,912	-31,655	-872,847
DISTDEPEXP-D	-46,534	-8,896	-55,430	-42,388	-12,877	-7	-2,690	0	0	-1,254	-114,646
DISTDEPEXP-C	-54,994	-3,850	-58,844	-1,751	-23	0	0	0	0	-4	-60,622
Total Allocation of CIAC Amortization *as per sch 10.5.1 (p. 5 & 6) PUB MFR3 Attachment*	-105,344	49,023	-56,321	-288,076	-148,564	-278	-87,336	-387,602	-128,941	-32,964	-1,130,083

REFERENCE:

Application p. 35 of 40; Appendix 1 Atrium Report pp. 24-25

PREAMBLE TO IR (IF ANY):

Application p. 35: "Centra's contracted upstream peak capacity does not include the peak requirements of the Interruptible class. As a result, Centra proposes to exclude the Interruptible Class from the allocation of year-round pipeline capacity

As the needs of the Interruptible Class are served using gas from storage, Centra proposes to include the Interruptible Class in the allocation of storage and related pipeline injections/redelivery capacity costs."

At Appendix 1 pages 24-25, Atrium states: "In place of the aforementioned analysis, as an alternative approach for storage and related pipeline injection and redelivery capacity, Centra should use the winter season demand in excess of summer season demand. Winter season throughput would be an alternative allocation method for Supplemental Supply. An alternative allocation method for year-round pipeline capacity should be peak day demand, at the design day level. For interruptible customers, Centra should consider the use of a 100% load factor contribution to the peak day allocator. This will prevent these customers from escaping some peak day responsibility; that is, if Centra's capacity resources can accommodate the cumulative design day peak demands of the interruptible customer group."

QUESTION:

a) Please explain why Centra rejects Atrium's recommendation to use a 100% load factor and include Interruptible customer loads in the allocation of year- round upstream pipeline capacity costs.
b) When calculating and modeling the optimum levels of storage and pipeline capacity for Centra to hold (as was done when Centra prepared to replace its storage and transportation assets in 2013 and 2020), please confirm whether Centra included

Interruptible customer loads in the modeling. If not confirmed, does this mean that Centra did not contract for any storage or U.S. pipeline capacity to serve Interruptible customers?

c) Please confirm whether Centra specifically arranges any pipeline or storage capacity in order to serve Interruptible customer loads.

d) If Centra did not contract for U.S. pipeline and storage assets to serve Interruptible customer loads, and Interruptible customer loads are not part of Centra's peak requirements, please provide additional justification for allocating storage and related pipeline capacity costs to the Interruptible class.

RESPONSE:

a) Atrium's recommendation was to include interruptible demand at 100% load factor if Centra's year-round upstream capacity could accommodate the cumulative design day peak demands of the interruptible group. Since that is not the case, Centra is proposing to exclude them from the Coincident Peak allocator used for upstream pipeline capacity.

Response to parts b) through d):

When modeling upstream transportation and storage capacity prior to 2013 and 2020, Centra included Interruptible load recognizing that gas from storage serves this load if Firm customer demand can be met. However, Interruptible load was excluded from upstream *peak* capacity determination in the modeling, as Centra does not contract for services to meet peak Interruptible load.

REFERENCE:

Application p. 35 of 40

PREAMBLE TO IR (IF ANY):

Centra states: "Atrium's alternative treatment for both the year-round pipeline capacity (Coincident Peak) and contracted storage and associated pipeline capacity (Winter Season Demand in excess of Summer Season Demand) is reflective of cost causation and the latter is anticipated to provide similar results and is much easier to understand and far less complex to implement than pursuing the more costly analysis for the seasonal Resource Stack-based option."

QUESTION:

Please explain why TCPL STS Demand costs are allocated using Coincident Peak and not Winter Season Demand in excess of Summer Season Demand, considering it is a storage service that facilitates the other storage services which are allocated with the Winter Season Demand in Excess of Summer Season Demand allocator.

RESPONSE:

The main function of TCPL Storage Transportation Service ("STS") contract is to facilitate the movement of Western Canadian gas to storage in summer and gas from storage to the Manitoba market in winter. STS does this by connecting to our US transportation contracts at Emerson.

Given that STS specifically facilitates storage injections and withdrawals, it should be allocated consistent with other storage-related transportation using the Winter Season Demand in Excess of Summer Season Demand.

REFERENCE:

Application p. 36 of 40; Appendix 4 p. 1 of 16; PUB MFR 8 (Attachment 2, p. 15 of 25)

PREAMBLE TO IR (IF ANY):

"Centra is also recommending the elimination of the Co-op Class from the Cost of Service Study given the low likelihood of increased participation by customers that would fall into this class. In Centra's view, it is appropriate to close the Co-op Class and proposes to reflect that change at the next GRA."

Centra's illustrative results from the proposed Cost of Service Study methodology show a $14,725 cost allocation to the Co-op Class.

MFR 8 – Attachment 2 (p. 15 of 25): "Recommendation 32 […] Centra accepts CA's recommendation. Centra implemented a Co-op Class in 2003 that was created specifically for the North Cypress Energy Co-op (NCEC) with eligibility criteria such that all future Co-op entities served directly from Centra's Transmission facilities (among other criteria as set out in Centra's Terms and Conditions of Service) are eligible for the service option. Since that time, NCEC has dissolved, Centra acquired its assets and no customer has been eligible or expressed an interest for the service option. It is Centra's view that it is appropriate to close the Co-op Class service option."

QUESTION:

a) Please confirm whether Centra's proposal to eliminate the Co-op class, if approved by the Board, will be implemented in the Cost of Service Study filed in Centra's next General Rate Application.
b) Please explain why gas co-operatives formed in Manitoba as opposed to being served by Centra or its predecessor utilities. Do the same conditions exist today as existed when the co-operatives formed? If not, explain what has changed.

c) Please confirm whether the Growth and Prosperity Group, seeking to serve the south-central portion of Manitoba with gas, is a candidate to potentially form a gas co-operative. If not, explain why not.

RESPONSE:

a) Confirmed.

b) It is Centra's understanding that gas co-operatives formed in Manitoba with the intent of achieving potentially lower pipeline installation costs by having local agricultural producers perform the required pipeline installations themselves. Centra is not in a position to comment on what local agricultural producers labour and/or equipment costs are today relative to Centra's costs to install pipelines and as such, cannot confirm if the same conditions exist today.

c) It is Centra's understanding that the Growth and Prosperity Group is a candidate to potentially form a gas co-operative.

REFERENCE:

Application pp. 4 and 36 of 40; Appendix 4 (p. 4 of 16); MFR-6 p. 12 of 14; MFR 7-Attachment 2 p. 14 of 102

PREAMBLE TO IR (IF ANY):

"Customer classes currently served by Centra include: Small General Service Class ("SGS") – Residential ("SGS-R") and small commercial ("SGS-C") customers with an annual consumption less than 680,000 m3 […]"

Centra's Cost of Service Study methodology currently results in costs allocated to the SGS-R and SGS-C sub-classes, yet these individual cost allocations results are totaled together to inform the existing Small General Service rates.

MFR 7-Attachment 2 (p. 14 of 102, lines 15-23): "Centra weighed these difficulties against the potential benefits of having a separate Residential rate. The cost study indicates that residential customers are paying cost-based rates today. Based on the cost study, there is no reason to believe that a separate rate would offer any benefits to residential customers. Furthermore, the distinctions between the two groups do not appear to be great. Since the practical effects of a separate Residential rate would be to create artificial distinctions, without any significant change in rate levels, Centra has determined to reject RJRA's recommendation to create a separate Residential rate at this time. However, the residential customers will remain separated in the Cost of Service study so that the situation can be monitored in the future."

MFR-6 (p. 12 of 14): "Based on the cost analysis undertaken, there is not a great deal of difference in the cost to serve residential and commercial customers in the SGS class which suggests that these customers are reasonably similarly situated. […] It became apparent during the implementation of residential and non-residential primary gas rates that significant issues exist with regard to the appropriate definition of residential. […] As a result, Centra does not have a compelling cost based reason to separate these customers from the SGS class and it is on this basis that Centra does not believe it is necessary or desirable to do so."

QUESTION:

a) Please explain why Centra proposes to continue to segregate the SGS-R and SGS-C sub-classes in its Cost of Service Studies.
b) Please explain whether there are any differences in the cost to serve these sub-classes such that it makes sense to set separate rates for each.

RESPONSE:

Response to parts a) and b):

Centra proposes to continue to segregate the SGS-R and SGS-C subclasses in its cost of service studies as the necessary data to track and allocate costs separately is readily available and it is not administratively more difficult. Centra does not see a benefit to amalgamating these subclasses at this time, however the separate allocation will allow Centra to monitor any cost distinctions between the two groups and assess whether separate rates may be warranted in the future once the new cost allocation methodology has been determined.

REFERENCE:

Application pp. 2, 34 of 40; Appendix 1 Atrium Report p.28 and Appendix C, Exhibit Centra-6 (Attachment 1)

PREAMBLE TO IR (IF ANY):

At page 2 of the Application, Centra states: "Based on this review Centra is proposing the following amendments to its Cost of Service Methodology:

- Refresh the development of the customer component of distribution mains using either a zero intercept or minimum system method."

At page 34 of the Application, Centra states: "Centra acknowledges that the use of a minimum system or zero-intercept study to classify costs between Demand and Customer could produce results different than Centra's current split, which is based on the historic results of a diameter length study. While the current level of detail in its plant records is insufficient for Centra to undertake a zero-intercept study at this time; some work is currently underway that may provide sufficient granularity to perform the study in the future. As the current 67%/33% split between Demand and Customer is within industry standards, Centra is not proposing or committing to undertake any additional studies on this matter at this time and awaits feedback from stakeholders as part of this proceeding."

Atrium provided the allocation methodologies of several Canadian utilities at pages 28 and 29 and in Appendix C of its report.

2021 COSMR Exhibit Centra-6 Attachment 1: "Based on its review of Atriums recommendations, Centra is proposing the following amendments to its Cost of Service Methodology: […] Refresh the development of the customer component of distribution mains using either a zero intercept or minimum system method;"

QUESTION:

a) Please explain which industry standards are referenced in Centra's statement that "the current 67%/33% split […] is within industry standards". For example, is Centra's statement based on Atrium's review of Canadian gas LDCs as presented in section 8.0 of Atrium's report (Appendix 1 of Centra's Application)?

b) Please provide the mains classification used by Heritage Gas in its cost of service study. Heritage Gas' methodology can be found at page 16-9 of its 2011 General Rate Application, filed as Exhibit H-1 in Nova Scotia Utility and Review Board matter M04196 (reference https://uarb.novascotia.ca/fmi/webd/UARB15).

c) Please explain what is missing from Centra's plant records that preclude performing a zero-intercept study for distribution mains.

d) Further explain the work that is "currently underway that may provide sufficient granularity to perform the study in the future" and provide an estimated timeline for when this work may be complete.

e) Please explain whether Centra has any limitations regarding the development of a minimum system study as proposed by Atrium.

f) Please reconcile the statement "Centra is not proposing or committing to undertake any additional studies on this matter at this time and awaits feedback from stakeholders as part of this proceeding." with the statement at page 2 of the Application: "Based on this review Centra is proposing the following amendments to its Cost of Service Methodology: Refresh the development of the customer component of distribution mains using either a zero intercept or minimum system method."

g) If required (e.g. due to Centra's response to item (f) above), please file a revised detailed summary of Centra's proposed changes to its Cost of Service Study (inclusive of the proposed treatments of Interruptible class demand in Coincident Peak Day allocations and Centra's support of Atrium's proposal to index service line study to current costs, both of which are not specifically itemized in the Centra-6 Attachment 1 summary).

RESPONSE:

a) Centra's statement to industry standards is in reference to Atrium's review of Canadian LDCs as well as previous research done at the time of the Christensen report that shows Centra's customer and demand split falls within a reasonable range.

b) The Heritage Gas study concluded the following:

- The diameter length method was most appropriate for Heritage Gas; and
- The classification of mains should be altered such that the portion classified as site related would be reduced from 66.7% of mains to 54%.

Response to parts c) through e):

The additional work noted in Centra's submission was an analysis of gas pipe data that was required for input into an IFRS Compliant ASL Depreciation Study. The primary purpose of this analysis was to allocate the cost of distribution mains between steel and plastic and at the time of filing its application, Centra anticipated that additional granularity such as pipeline size, footage by vintage year may also be available. The depreciation study analysis has since been completed. Centra has reviewed the available data with Atrium and they have confirmed that a zero-intercept study cannot be completed. A zero-intercept study requires pipeline data by size, type, footage, and installed original cost by vintage year. Centra's records are insufficient to determine the installed cost broken down by vintage year for each of those categories (i.e pipeline size, type and footage). Atrium has also advised that while it may be possible to complete a minimum system study, due to previous mergers of company data upon acquisition (ICG and GWC) numerous estimates and assumptions would be required.

Response to parts f) and g):

Centra's summary on page 2 should not have included the reference to refreshing the customer component of distribution mains. Centra's proposals include:

- Replace Peak and Average with a Coincident Peak Day allocation method for downstream capacity costs. Centra proposes to include the Interruptible class in the calculation of the Coincident Peak Day allocator.
- Utilize Direct Assignment of transmission plant to the Special Contract and Power Stations Classes.
- Replace the Peak and Average allocator for upstream capacity costs with a Coincident Peak Day allocation for year-round pipeline capacity, and Winter Season Demand in excess of Summer Season Demand for storage and related pipeline capacity. Centra proposes to exclude the Interruptible class from the allocator for year-round pipeline capacity but include the Interruptible class in the allocation or storage and related pipeline capacity.
- Indexing the results of the service line study.

REFERENCE:

Application pp. 38-40

PREAMBLE TO IR (IF ANY):

"[…] Centra is not seeking approval of natural gas sales rates as part of this Application as rate changes are typically sought through a GRA. However, […], the illustrative results for certain customer classes are significant such that contrary to typical convention, the PUB and parties may want to consider as part of this regulatory proceeding an interim measure to immediately adjust current rates for the Special Contract and Power Station Classes. If the PUB is so inclined, a practical potential interim approach for consideration would be to reinstate the Special Contract Class's non-gas portion of rates to those that were in effect prior to the 2019/20 GRA. […] the Power Station Class could correspondingly absorb the revenue deficiency created by the immediate interim relief provided to the Special Contract Class."

QUESTION:

a) File Schedule 11.4.0 from the 2019/20 Centra GRA compliance filing of October 25, 2019.
b) File Schedules 11.1.0 through to 11.1.5 and 12.4.1 from the 2013/14 Centra GRA compliance filing of July 31, 2013.
c) File Schedules 5.0.0 through to 5.4.7 and 6.3.0 through 6.4.0 from the 2015/16 Centra COG Pre-Hearing Update (September 11, 2015).

RESPONSE:

a) Please see Attachment 1 to this response

b) Please see Attachment 2 to this response

c) Please see Attachment 3 to this response

Centra Gas Manitoba Inc. — **Schedule 11.4.0**
2019/20 GRA Rates Application-Reflecting Order 152/19 — **October 25, 2019**
Gas & Non-Gas Components of Base Rates

1										
2		Small Gen.	Large Gen	High			Special	Power		Main Line
3		Service	Service	Volume	Cooperative	Main Line	Contracts	Stations	Interruptible	Interruptible
4		SGS-Total	LGS	HVF	CO-OP	ML	SC	GS	INT	ML-INT
5										
6	**Aug 1/19 Approved Base Rates**									
7										
8	BMC Rate	$14.00	$77.00	$1,118.31	$274.06	$2,353.33	$117,914.17	$8,026.07	$1,042.72	$2,353.33
9										
10	*Demand*									
11	Transportation to Centra (Gas)			301.21	458.25	534.63	-	-	140.01	215.41
12	Transportation to Centra (Non-Gas)			6.18	9.88	10.98	-	-	2.92	4.50
13	Transportation to Centra (Total)			307.39	468.13	545.62	-	-	142.94	219.90
14	M3			0.3074	0.4681	0.5456	-	-	0.1429	0.2199
15										
16	Distribution to Customer (Gas)			0.79	1.17	1.35	-	0.52	0.42	1.35
17	Distribution to Customer (Non-Gas)			149.52	128.61	156.26	-	4.28	76.80	156.26
18	Distribution to Customer (Total)			150.31	129.78	157.61	-	4.79	77.22	157.61
19	M3			0.1503	0.1298	0.1576	-	0.0048	0.0772	0.1576
20										
21	*Commodity*									
22	Transportation to Centra (Gas)	46.75	44.60	14.69	1.10	1.41	-	-	6.85	1.51
23	Transportation to Centra (Non-Gas)	7.11	7.09	4.83	4.53	4.54	-	-	4.68	4.56
24	Transportation to Centra (Total)	53.87	51.69	19.52	5.63	5.95	-	-	11.53	6.07
25	M3	0.0538	0.0516	0.0196	0.0057	0.0060	-	-	0.0115	0.0061
26										
27	Distribution to Customer (Gas)	1.36	1.26	0.92	-	1.21	0.14	8.30	3.75	1.21
28	Distribution to Customer (Non-Gas)	85.22	34.46	6.39	-	0.01	0.00	0.09	2.90	0.01
29	Distribution to Customer (Total)	86.59	35.72	7.32	-	1.22	0.14	8.39	6.64	1.22
30	M3	0.0866	0.0357	0.0073	0.0001	0.0012	0.0001	0.0083	0.0066	0.0012

Centra Gas Manitoba Inc.
2013/14 General Rates Application - Reflecting Order 85/13
Summary of Allocated Costs by Customer Class
2013/14 Test Year

Schedule 11.1.0
July 31, 2013

1	Cost of Service Elements									
2		SGS				LGS				
3		Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
4										
5	Cost of Gas	22,699,418	2,966,996	0	25,666,414	16,294,343	2,140,304	0	18,434,647	
6	Other Income	-54,350	-646	-1,664,978	-1,719,974	-39,030	-466	-57,243	-96,740	
7	Operating & Maintenance Expenses	6,276,605	74,565	46,331,430	52,682,600	4,507,454	53,837	6,027,205	10,588,496	
8	Depreciation & Amortization	3,561,963	4,179,855	17,253,445	24,995,263	2,230,039	2,450,926	2,313,705	6,994,670	
9	Capital & Other Taxes	3,087,945	649,476	9,063,387	12,800,808	2,217,020	419,363	1,515,110	4,151,494	
10	Finance Expense	2,202,169	1,626,785	7,616,470	11,445,423	1,579,914	1,050,238	1,313,622	3,943,774	
11	Corporate Allocation	1,559,518	1,152,046	5,393,782	8,105,346	1,118,853	743,751	930,272	2,792,876	
12	Net Income	389,879	288,011	1,348,446	2,026,336	279,713	185,938	232,568	698,219	
13										
14	Total Cost of Service	39,723,147	10,937,089	85,341,981	136,002,216	28,188,308	7,043,889	12,275,238	47,507,435	
15										
16										
17		HVF				Cooperative				
18		Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
19										
20	Cost of Gas	3,609,822	537,151	0	4,146,973	9,100	599	0	9,698	
21	Other Income	-11,374	-104	-9,415	-20,893	-16	0	-24	-40	
22	Operating & Maintenance Expenses	1,313,557	11,991	1,021,746	2,347,294	1,889	20	2,569	4,477	
23	Depreciation & Amortization	569,749	144,729	151,419	865,897	510	1	587	1,098	
24	Capital & Other Taxes	623,593	60,819	73,786	758,199	581	103	300	984	
25	Finance Expense	443,047	152,191	58,834	654,071	345	258	205	808	
26	Corporate Allocation	313,754	107,778	41,664	463,196	244	183	145	572	
27	Net Income	78,438	26,944	10,416	115,799	61	46	36	143	
28										
29	Total Cost of Service	6,940,586	1,041,499	1,348,451	9,330,536	12,712	1,210	3,819	17,741	
30										
31										
32		Main Line				Special Contract				
33		Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
34										
35	Cost of Gas	366,404	197,279	0	563,683	[redacted]				1d
36	Other Income	-5,537	-13	-806	-6,357	-5,131	-1	-112	-5,244	
37	Operating & Maintenance Expenses	639,484	1,515	87,292	728,291	592,612	120	10,881	603,614	
38	Depreciation & Amortization	183,223	287,974	14,451	485,648	14,310	-15	12,374	26,669	
39	Capital & Other Taxes	193,819	32,016	7,436	233,271	366,014	27	7,715	373,756	
40	Finance Expense	112,809	80,257	6,022	199,087	199,300	64	5,587	204,951	
41	Corporate Allocation	79,888	56,836	4,264	140,988	141,139	45	3,956	145,141	
42	Net Income	19,972	14,209	1,066	35,247	35,285	11	989	36,285	
43										
44	Total Cost of Service	1,590,062	670,073	119,724	2,379,859	[redacted]				1e
45										
46										
47		Power Station				Interruptible				
48		Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
49										
50	Cost of Gas	[redacted]				1,141,020	465,495	0	1,606,515	1d
51	Other Income	-746	-2	-270	-1,017	-3,746	-77	-4,099	-7,922	
52	Operating & Maintenance Expenses	86,114	236	21,765	108,116	432,553	8,899	444,144	885,596	
53	Depreciation & Amortization	-94,253	-29	67,841	-26,441	172,632	144,506	71,126	388,264	
54	Capital & Other Taxes	35,691	53	43,508	79,252	194,774	48,832	36,044	279,650	
55	Finance Expense	19,024	125	31,710	50,860	137,673	122,215	29,133	289,022	
56	Corporate Allocation	13,473	89	22,457	36,018	97,497	86,549	20,631	204,677	
57	Net Income	3,368	22	5,614	9,004	24,374	21,637	5,158	51,169	
58										
59	Total Cost of Service	[redacted]				2,196,777	898,057	602,138	3,696,972	1e
60										
61										
62		Primary Gas				Supplemental Gas - Firm				
63		Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
64										
65	Cost of Gas	[redacted]				[redacted]				1a
66	Other Income									
67	Operating & Maintenance Expenses									
68	Depreciation & Amortization									
69	Capital & Other Taxes									1e
70	Finance Expense									
71	Corporate Allocation									
72	Net Income									
73										
74	Total Cost of Service	[redacted]				[redacted]				1e
75										
76										
77		Supplemental Gas - Interruptible				Fixed Price Offering				
78		Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
79										
80	Cost of Gas	[redacted]				0	928,401	0	928,401	1a
81	Other Income					0	-39	-1,071	-1,110	
82	Operating & Maintenance Expenses					0	4,531	123,657	128,188	
83	Depreciation & Amortization					0	317	108,642	108,959	
84	Capital & Other Taxes					0	440	1,876	2,316	1e
85	Finance Expense					0	971	1,067	2,038	
86	Corporate Allocation					0	687	756	1,443	
87	Net Income					0	172	189	361	
88										
89	Total Cost of Service	[redacted]				0	935,480	235,117	1,170,596	1e
90										
91										
92										
93		Unassigned				Total				
94		Demand	Energy	Customer	Total	Demand	Energy	Customer	Total	
95										
96	Cost of Gas	0	0	0	0	44,153,806	155,617,841	0	199,771,646	
97	Other Income	0	0	0	0	-119,931	-7,612	-1,738,018	-1,865,560	
98	Operating & Maintenance Expenses	0	0	0	0	13,850,269	879,043	54,070,688	68,800,000	
99	Depreciation & Amortization	0	0	0	0	6,638,174	7,258,817	19,993,588	33,890,579	
100	Capital & Other Taxes	0	0	0	0	6,719,437	1,281,400	10,749,163	18,750,000	
101	Finance Expense	0	0	0	0	4,694,280	3,188,069	9,062,650	16,945,000	
102	Corporate Allocation	0	0	0	0	3,324,365	2,257,706	6,417,929	12,000,000	
103	Net Income	0	0	0	0	831,091	564,427	1,604,482	3,000,000	
104										
105	Total Cost of Service	0	0	0	0	80,091,492	171,039,691	100,160,483	351,291,665	

Centra Gas Manitoba Inc.
2013/14 General Rates Application - Reflecting Order 85/13
Unit Cost Component Summary
2013/14 Test Year

Schedule 11.1.1
July 31, 2013

	System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
1 REVENUE REQUIREMENTS														
2 Upstream Demand ($)	[redacted]													
3 Upstream Commodity ($)														
4 Upstream Customer ($)														
5 Upstream Total ($)														
6														
7 Downstream Demand ($)														1e
8 Downstream Commodity ($)														
9 Downstream Customer ($)														
10 Downstream Total ($)														
11														
12 Total (incl. gas costs)														
13														
14														
15 MONTHLY BILLING DETERMINANTS														
16 Upstream Demand (10^3m^3-day)	[redacted]													
17 Upstream Commodity (10^3m^3)														
18 Upstream Customer (customers)														
19														1d
20 Downstream Demand (10^3m^3-day)														
21 Downstream Commodity (10^3m^3)														
22 Downstream Customer (customers)														
23														
24 PERCENT IN DEMAND CHARGE		0.0%	0.0%	65.0%	100.0%	100.0%	100.0%	100.0%	65.0%	100.0%	100.0%	100.0%	100.0%	
25														
26 RESULTING UNIT CHARGES														
27 Upstream Demand ($/$10^3m^3$-day)	362.983	0.000	0.000	238.586	370.218	378.189	0.000	0.000	112.202	0.000	0.000	0.000	0.000	
28 Upstream Commodity ($/$10^3m^3$)	111.921	39.837	39.020	15.593	4.482	4.925	0.000	0.000	9.461	114.589	160.504	171.015	121.180	
29 Upstream Customer ($/customer)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
30														
31 Downstream Demand ($/$10^3m^3$-day)	209.902	0.000	0.000	166.595	131.000	181.782	88.360	4.479	85.081	0.000	0.000	0.000	0.000	
32 Downstream Commodity ($/$10^3m^3$)	6.539	34.614	31.499	9.441	0.000	4.472	0.148	8.045	7.082	0.000	0.000	0.000	0.000	
33 Downstream Customer ($/customer)	30.447	26.717	131.178	1,221.423	318.213	1,247.128	3,449.187	8,026.073	1,254.453	0.000	0.000	0.000	0.000	

Centra Gas Manitoba Inc.
2013/14 General Rates Application - Reflecting Order 85/13
Comparison of Gas Costs vs. Non-Gas Costs
2013/14 Test Year

Schedule 11.1.2
July 31, 2013

	Gas Costs vs. Non-Gas Costs	System Total	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FRPGS	
1	REVENUE REQUIREMENTS														
2	Upstream Demand ($)														
3	Gas Costs	43,955,362	22,621,815	16,238,578	3,594,067	9,068	355,920	0	0	1,135,913	0	0	0	0	
4	Non-gas Costs	1,556,273	800,943	574,939	127,251	321	12,602	0	0	40,218	0	0	0	0	
5	Total	45,511,635	23,422,758	16,813,518	3,721,318	9,389	368,521	0	0	1,176,131	0	0	0	0	
6		0	0	0	0	0	0	0	0	0	0	0	0	0	
7	Upstream Commodity ($)														
8	Gas Costs	153,403,961	2,116,866	1,531,487	342,330	599	35,666	0	0	250,749	[redacted]			928,401	
9	Non-gas Costs	4,379,607	1,567,353	1,149,807	282,892	611	30,808	0	0	211,025				7,079	1a, 1e
10	Total	157,783,568	3,684,220	2,681,294	625,222	1,210	66,473	0	0	461,774				935,480	
11		0	0	0	0	0	0	0	0	0	0	0	0	0	
12	Upstream Customer ($)														
13	Gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
14	Non-gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
15	Total	0	0	0	0	0	0	0	0	0	0	0	0	0	
16															
17	Upstream Total ($)														
18	Total Gas Costs	197,359,323	24,738,681	17,770,065	3,936,397	9,667	391,585	0	0	1,386,662	[redacted]			928,401	
19	Total Non-gas Costs	5,935,880	2,368,296	1,724,747	410,143	932	43,409	0	0	251,242				7,079	1e
20	Total Upstream Costs	203,295,203	27,106,977	19,494,812	4,346,540	10,600	434,994	0	0	1,637,904				935,480	
21		0	0	0	0	0	0	0	0	0	0	0	0	0	
22	Downstream Demand ($)														
23	Gas Costs	198,444	77,603	55,765	15,755	31	10,484	[redacted]		5,107	0	0	0	0	
24	Non-gas Costs	34,381,413	16,222,786	11,319,025	3,203,513	3,291	1,211,056	1,343,529	62,672	1,015,540	0	0	0	0	2d, 1e
25	Total	34,579,857	16,300,389	11,374,790	3,219,268	3,322	1,221,540	[redacted]		1,020,647	0	0	0	0	
26															
27	Downstream Commodity ($)														
28	Gas Costs	2,213,880	850,130	608,817	194,821	0	161,613	[redacted]		214,746	0	0	0	0	
29	Non-gas Costs	11,042,243	6,402,739	3,753,778	221,456	0	441,986	252	494	221,537	0	0	0	0	2d, 1e
30	Total	13,256,123	7,252,869	4,362,595	416,277	0	603,600	[redacted]		436,283	0	0	0	0	
31															
32	Downstream Customer ($)														
33	Gas Costs	0	0	0	0	0	0	[redacted]		0	0	0	0	0	
34	Non-gas Costs	100,160,483	85,341,981	12,275,238	1,348,451	3,819	119,724	41,390	192,626	602,138	0	0	0	235,117	2d. 1e
35	Total	100,160,483	85,341,981	12,275,238	1,348,451	3,819	119,724	[redacted]		602,138	0	0	0	235,117	
36															
37	Downstream Total ($)														
38	Total Gas Costs	2,412,324	927,733	664,582	210,576	31	172,097	[redacted]		219,853	0	0	0	0	
39	Total Non-gas Costs	145,584,139	107,967,507	27,348,041	4,773,420	7,110	1,772,767	1,385,171	255,792	1,839,214	0	0	0	235,117	2d, 1e
40	Total Downstream Costs	147,996,463	108,895,239	28,012,623	4,983,996	7,141	1,944,864	[redacted]		2,059,067	0	0	0	235,117	
41															
42	Grand Total Gas Costs	199,771,646	25,666,414	18,434,647	4,146,973	9,698	563,683	[redacted]		1,606,515	[redacted]			928,401	
43	Grand Total Non-gas Costs	151,520,019	110,335,803	29,072,788	5,183,563	8,042	1,816,176	1,385,171	255,792	2,090,457				242,196	2d, 1e
44	Grand Total	351,291,665	136,002,216	47,507,435	9,330,536	17,741	2,379,859	[redacted]		3,696,972				1,170,596	
45															
46															

47 Calculation of the Primary Gas Overhead Rate: [redacted] line 9, PG column)
48 10^3m^3 (Schedule 11.1.1, line 17, PG column)
49 0.87 10^3m^3

Calculation of the Fixed Rate Primary Gas PCR 242,196 (lines 9 & 34, FPO column)
7,720 (10^3m^3 (Schedule 11.1.1, line 17, FPO column) 1e
31.37 per 10^3m^3

Centra Gas Manitoba Inc.
2013/14 General Rate Application - Reflecting Order 85/13
Total Functionalization By Customer Class
2013/14 Test Year

Schedule 11.1.3
July 31, 2013

		System Total	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FPO	
1	PRODUCTION																
2	Demand	0	[redacted]														
3	Energy	150,263,376															1a
4	Customer	0															
5	Total	150,263,376															
6																	
7	PIPELINE																
8	Demand	31,483,880	[redacted]														
9	Energy	1,625,773															1a
10	Customer	0															
11	Total	33,109,652															
12																	
13	STORAGE																
14	Demand	14,027,755	[redacted]														
15	Energy	5,894,419															1a
16	Customer	0															
17	Total	19,922,174															
18																	
19	TRANSMISSION																
20	Demand	10,738,612	[redacted]														
21	Energy	13,256,123															1a
22	Customer	0															
23	Total	23,994,735															
24																	
25	DISTRIBUTION																
26	Demand	23,841,245	10,044,758	1,680,073	11,724,831	8,418,239	2,363,282	1,828	606,927	[redacted]		726,137	[redacted]			0	
27	Energy	0	0	0	0	0	0	0	0			0				0	2d, 1e
28	Customer	10,317,559	9,355,289	663,774	10,019,063	293,506	3,463	2	16			1,506				0	
29	Total	34,158,804	19,400,047	2,343,847	21,743,894	8,711,745	2,366,745	1,830	606,942			727,643				0	
30																	
31	ONSITE																
32	Demand	0	0	0	0	0	0	0	0			0				0	
33	Energy	0	0	0	0	0	0	0	0			0				0	
34	Customer	89,842,924	68,487,724	6,835,193	75,322,918	11,981,732	1,344,988	3,817	119,709			600,632				235,117	2d, 1e
35	Total	89,842,924	68,487,724	6,835,193	75,322,918	11,981,732	1,344,988	3,817	119,709			600,632				235,117	
36																	
37	TOTAL SERVICE																
38	Demand	80,091,492	33,977,683	5,745,464	39,723,147	28,188,308	6,940,586	12,712	1,590,062			2,196,777				0	
39	Energy	171,039,691	8,179,683	2,757,406	10,937,089	7,043,889	1,041,499	1,210	670,073			898,057				935,480	2d, 1e
40	Customer	100,160,483	77,843,013	7,498,968	85,341,981	12,275,238	1,348,451	3,819	119,724			602,138				235,117	
41	Total	351,291,665	120,000,379	16,001,837	136,002,216	47,507,435	9,330,536	17,741	2,379,859			3,696,972				1,170,596	

Centra Gas Manitoba Inc.
2013/14 General Rate Application - Reflecting Order 85/13
Allocation Results of Rate Base
2013/14 Test Year

Account Description	Account Code	Total Allocated Dollars	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Allocation Factor	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF
RATE BASE DETAILS											
I. GAS PLANT IN SERVICE											
A. INTANGIBLE PLANT											
Franchises & Consents	401	22,370		0	22,370		13,385	1,907	15,292	4,870	928
Other Intangible Plant	402	13,363,818		0	13,363,818		7,996,277	1,139,077	9,135,354	2,909,512	554,306
Sub-total	401-402	13,386,188		0	13,386,188		8,009,662	1,140,984	9,150,646	2,914,382	555,234
B. PRODUCTION PLANT											
(Reserved)	-	0		0	0		0	0	0	0	0
Sub-total	420-424	0		0	0		0	0	0	0	0
C. LOCAL STORAGE PLANT											
Land	440	0		0	0		0	0	0	0	0
Structures & Improvements	442	0		0	0		0	0	0	0	0
Sub-total	440-449	0		0	0		0	0	0	0	0
D. TRANSMISSION PLANT											
Land	460	791,258		0	791,258		265,083	44,344	309,426	222,353	62,819
Structures & Improvements	461	76,000		0	76,000		25,461	4,259	29,720	21,357	6,034
Structures & Improvements - M&R	463	1,040,393		0	1,040,393		348,547	58,306	406,852	292,363	82,599
Mains	465	96,265,407		0	96,265,407		32,250,313	5,394,892	37,645,205	27,051,728	7,642,698
Measuring & Reg. Equipment	467	7,702,502		0	7,702,502		2,580,450	431,662	3,012,113	2,164,495	611,517
Other Transmission Equipment	469	0		0	0		0	0	0	0	0
Sub-total	460-469	105,875,559		0	105,875,559		35,469,854	5,933,463	41,403,317	29,752,295	8,405,667
E. DISTRIBUTION PLANT											
Land	470	1,090,779		0	1,090,779		707,972	99,104	807,076	224,188	37,282
Computer Equipment - Hardware	471	469,176		0	469,176		304,519	42,628	347,147	96,430	16,036
Structures & Improvements	472	1,544,025		0	1,544,025		667,794	111,693	779,486	559,606	156,990
Structures & Improvements: M & R	472.1	4,426,137		0	4,426,137		1,792,047	299,743	2,091,790	1,502,093	422,153
Services	473	225,205,587		0	225,205,587		180,467,571	24,423,176	204,890,747	19,226,085	663,238
Regulators	474	52,751,366		0	52,751,366		27,777,231	5,393,099	33,170,330	18,209,368	861,202
Regulators & Meters Installations	474.1	0		0	0		0	0	0	0	0
Mains	475	182,038,564		0	182,038,564		107,508,372	12,682,736	120,191,108	45,710,728	12,359,642
Measuring & Reg. Equipment	477	35,630,579		0	35,630,579		13,570,266	2,269,799	15,840,065	11,374,590	3,196,748
Telemetry Equipment	477.1	4,038,732		0	4,038,732		1,635,195	273,507	1,908,702	1,370,620	385,203
Meters	478	42,745,268		0	42,745,268		22,508,330	4,370,114	26,878,444	14,755,339	697,846
AMR/ERT Modules	479	0		0	0		0	0	0	0	0
Other Distribution Equipment	-	0		0	0		0	0	0	0	0
Sub-total	470-479	549,940,213		0	549,940,213		356,939,298	49,965,598	406,904,896	113,029,047	18,796,339
F. GENERAL PLANT											
Land	480	136,500		0	136,500		95,958	8,565	104,523	21,008	4,657
Structures & Improvements	482	9,144,873		0	9,144,873		6,428,737	573,817	7,002,554	1,407,419	312,002
Leasehold Improvements	482.1	0		0	0		0	0	0	0	0
Office Furniture & Equipment	483	324,024		0	324,024		227,785	20,332	248,116	49,868	11,055
Target Adjustments	483.1	0		0	0		0	0	0	0	0
Computer Equipment: Software	483.2	0		0	0		0	0	0	0	0
Computer System Development	483.3	0		0	0		0	0	0	0	0
Transportation Equipment	484	277,928		0	277,928		195,380	17,439	212,820	42,774	9,482
Vehicle Conversion Kits	484.1	0		0	0		0	0	0	0	0
Heavy Work Equipment	485	361,615		0	361,615		211,327	30,066	241,393	80,654	16,178
Tools & Work Equipment	486	1,727,766		0	1,727,766		1,009,703	143,655	1,153,358	385,356	77,296
Rental Equipment: Conv. Bur.	487	0		0	0		0	0	0	0	0
Communication Equipment	488	0		0	0		0	0	0	0	0
Property, Plant & Equipment Gas Inventory	489	393,000		0	393,000		239,985	33,429	273,414	82,267	15,300
Sub-total	480-490	12,365,706		0	12,365,706		8,408,875	827,303	9,236,178	2,069,346	445,970
Sub-total Plant-in-Service		681,567,667		0	681,567,667		408,827,689	57,867,348	466,695,037	147,765,070	28,203,209
G. ADDITIONS TO UTILITY PLANT											
Construction Work in Progress		0		0	0		0	0	0	0	0
Other Additions		0		0	0		0	0	0	0	0
Sub-total		0		0	0		0	0	0	0	0
Total Utility Plant		**681,567,667**		**0**	**681,567,667**		**408,827,689**	**57,867,348**	**466,695,037**	**147,765,070**	**28,203,209**
II. ACCUMULATED DEPRECIATION											
Intangible Plant		-5,659,334		0	-5,659,334		-3,394,442	-482,070	-3,876,512	-1,206,654	-236,303
Production Plant		0		0	0		0	0	0	0	0
Local Storage Plant		0		0	0		0	0	0	0	0

Centra Gas Manitoba Inc.
2013/14 General Rate Application - Reflecting Order 85/13
Allocation Results of Rate Base
2013/14 Test Year

Account Description	Account Code	Total Allocated Dollars	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FPO
RATE BASE DETAILS											
I. GAS PLANT IN SERVICE											
A. INTANGIBLE PLANT											
Franchises & Consents	401	22,370	1	289	570	115	304	0	0	0	0
Other Intangible Plant	402	13,363,818	725	172,720	340,410	68,935	181,855	0	0	0	0
Sub-total	401-402	13,386,188	727	173,009	340,980	69,050	182,160	0	0	0	0
B. PRODUCTION PLANT											
(Reserved)	-	0	0	0	0	0	0	0	0	0	0
Sub-total	420-424	0	0	0	0	0	0	0	0	0	0
C. LOCAL STORAGE PLANT											
Land	440	0	0	0	0	0	0	0	0	0	0
Structures & Improvements	442	0	0	0	0	0	0	0	0	0	0
Sub-total	440-449	0	0	0	0	0	0	0	0	0	0
D. TRANSMISSION PLANT											
Land	460	791,258	124	41,804	122,498	11,871	20,362	0	0	0	0
Structures & Improvements	461	76,000	12	4,015	11,766	1,140	1,956	0	0	0	0
Structures & Improvements - M&R	463	1,040,393	163	54,966	161,068	15,609	26,773	0	0	0	0
Mains	465	96,265,407	15,084	5,085,881	14,903,265	1,444,283	2,477,263	0	0	0	0
Measuring & Reg. Equipment	467	7,702,502	1,207	406,938	1,192,458	115,562	198,214	0	0	0	0
Other Transmission Equipment	469	0	0	0	0	0	0	0	0	0	0
Sub-total	460-469	105,875,559	16,589	5,593,603	16,391,054	1,588,465	2,724,568	0	0	0	0
E. DISTRIBUTION PLANT											
Land	470	1,090,779	38	5,717	623	3,559	12,297	0	0	0	0
Computer Equipment - Hardware	471	469,176	16	2,459	268	1,531	5,289	0	0	0	0
Structures & Improvements	472	1,544,025	0	0	0	0	47,942	0	0	0	0
Structures & Improvements: M & R	472.1	4,426,137	838	278,314	0	0	130,949	0	0	0	0
Services	473	225,205,587	0	83,065	0	0	342,452	0	0	0	0
Regulators	474	52,751,366	0	83,645	0	0	426,821	0	0	0	0
Regulators & Meters Installations	474.1	0	0	0	0	0	0	0	0	0	0
Mains	475	182,038,564	0	0	0	0	3,777,087	0	0	0	0
Measuring & Reg. Equipment	477	35,630,579	17,349	2,107,531	313,332	1,789,355	991,609	0	0	0	0
Telemetry Equipment	477.1	4,038,732	765	253,954	0	0	119,487	0	0	0	0
Meters	478	42,745,268	0	67,779	0	0	345,860	0	0	0	0
AMR/ERT Modules	479	0	0	0	0	0	0	0	0	0	0
Other Distribution Equipment	-	0	0	0	0	0	0	0	0	0	0
Sub-total	470-479	549,940,213	19,006	2,882,464	314,223	1,794,445	6,199,793	0	0	0	0
F. GENERAL PLANT											
Land	480	136,500	9	1,445	1,198	215	1,757	1,214	203	18	254
Structures & Improvements	482	9,144,873	595	96,804	80,232	14,371	117,713	81,310	13,615	1,220	17,039
Leasehold Improvements	482.1	0	0	0	0	0	0	0	0	0	0
Office Furniture & Equipment	483	324,024	21	3,430	2,843	509	4,171	2,881	482	43	604
Target Adjustments	483.1	0	0	0	0	0	0	0	0	0	0
Computer Equipment: Software	483.2	0	0	0	0	0	0	0	0	0	0
Computer System Development	483.3	0	0	0	0	0	0	0	0	0	0
Transportation Equipment	484	277,928	18	2,942	2,438	437	3,578	2,471	414	37	518
Vehicle Conversion Kits	484.1	0	0	0	0	0	0	0	0	0	0
Heavy Work Equipment	485	361,615	21	5,300	10,860	1,934	5,275	0	0	0	0
Tools & Work Equipment	486	1,727,766	100	25,324	51,890	9,239	25,202	0	0	0	0
Rental Equipment: Conv. Bur.	487	0	0	0	0	0	0	0	0	0	0
Communication Equipment	488	0	0	0	0	0	0	0	0	0	0
Property, Plant & Equipment Gas Inventory	489	393,000	21	4,920	10,002	2,030	5,046	0	0	0	0
Sub-total	480-490	12,365,706	785	140,165	159,463	28,734	162,742	87,876	14,714	1,318	18,415
Sub-total Plant-in-Service		681,567,667	37,107	8,789,242	17,205,721	3,480,695	9,269,263	87,876	14,714	1,318	18,415
G. ADDITIONS TO UTILITY PLANT											
Construction Work in Progress		0	0	0	0	0	0	0	0	0	0
Other Additions		0	0	0	0	0	0	0	0	0	0
Sub-total		0	0	0	0	0	0	0	0	0	0
Total Utility Plant		**681,567,667**	**37,107**	**8,789,242**	**17,205,721**	**3,480,695**	**9,269,263**	**87,876**	**14,714**	**1,318**	**18,415**
II. ACCUMULATED DEPRECIATION											
Intangible Plant		-5,659,334	-371	-81,201	-145,231	-35,793	-77,269	0	0	0	0
Production Plant		0	0	0	0	0	0	0	0	0	0
Local Storage Plant		0	0	0	0	0	0	0	0	0	0

Centra Gas Manitoba Inc.
2013/14 General Rate Application - Reflecting Order 85/13
Allocation Results of Rate Base
2013/14 Test Year

Account Description	Account Code	Total Allocated Dollars	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Allocation Factor	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF
Transmission Plant		-29,697,916		0	-29,697,916		-9,941,491	-1,663,031	-11,604,522	-8,338,973	-2,362,740
Distribution Plant		-198,230,877		0	-198,230,877		-128,265,208	-17,848,805	-146,114,012	-40,197,897	-7,115,796
General Plant		-8,410,556		0	-8,410,556		-5,642,367	-568,837	-6,211,205	-1,477,096	-315,839
Retirement Work in Progress		0		0	0		0	0	0	0	0
Sub-total		-241,998,684		0	-241,998,684		-147,243,509	-20,562,743	-167,806,251	-51,220,620	-10,030,679
Plant Held For Future Use		0		0	0		0	0	0	0	0
Total Accumulated Depreciation		**-241,998,684**		**0**	**-241,998,684**		**-147,243,509**	**-20,562,743**	**-167,806,251**	**-51,220,620**	**-10,030,679**
III. OTHER RATE BASE											
Contributions in Aid of Construction		-53,061,703		0	-53,061,703		-19,973,160	-3,288,772	-23,261,932	-15,076,359	-4,105,594
Cash Working Capital		16,562,741		0	16,562,741		7,780,937	950,690	8,731,627	2,464,341	459,336
Security Deposits		-400,000		0	-400,000		-321,402	-22,804	-344,206	-45,689	-6,456
Gas in Storage		38,863,462		0	38,863,462		16,061,746	2,696,338	18,758,084	13,772,978	3,408,052
Investment in DSM		47 572 399		0	47 572 399		18 553 235	9 038 756	27 591 991	16 174 615	951 448
Total Other Rate Base		**49,536,898**		**0**	**49,536,898**		**22,101,356**	**9,374,208**	**31,475,564**	**17,289,886**	**706,786**
TOTAL RATE BASE		**489 105 881**		**0**	**489 105 881**		**283 685 536**	**46 678 814**	**330 364 350**	**113 834 336**	**18 879 317**

Centra Gas Manitoba Inc.
2013/14 General Rate Application - Reflecting Order 85/13
Allocation Results of Rate Base
2013/14 Test Year

Account Description	Account Code	Total Allocated Dollars	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FPO
Transmission Plant		-29,697,916	-4,650	-1,575,939	-4,595,396	-447,949	-767,747	0	0	0	0
Distribution Plant		-198,230,877	-9,532	-1,428,700	-155,352	-887,171	-2,322,417	0	0	0	0
General Plant		-8,410,556	-507	-79,265	-115,700	-17,785	-112,103	-58,230	-9,750	-874	-12,202
Retirement Work in Progress		0	0	0	0	0	0	0	0	0	0
Sub-total		-241,998,684	-15,060	-3,165,105	-5,011,678	-1,388,699	-3,279,536	-58,230	-9,750	-874	-12,202
Plant Held For Future Use		0	0	0	0	0	0	0	0	0	0
Total Accumulated Depreciation		**-241,998,684**	**-15,060**	**-3,165,105**	**-5,011,678**	**-1,388,699**	**-3,279,536**	**-58,230**	**-9,750**	**-874**	**-12,202**
III. OTHER RATE BASE											
Contributions in Aid of Construction		-53,061,703	-6,953	-2,301,075	-6,352,380	-636,449	-1,320,962	0	0	0	0
Cash Working Capital		16,562,741	846	149,063	74,183	12,639	180,154	3,753,189	628,442	56,302	52,617
Security Deposits		-400,000	-70	-561	-70	-140	-2,807	0	0	0	0
Gas in Storage		38,863,462	7,443	372,054	0	0	2,544,851	0	0	0	0
Investment in DSM		47 572 399	0	1 902 896	0	0	951 448	0	0	0	0
Total Other Rate Base		**49,536,898**	**1,267**	**122,377**	**-6,278,267**	**-623,950**	**2,352,685**	**3,753,189**	**628,442**	**56,302**	**52,617**
TOTAL RATE BASE		**489 105 881**	**23 314**	**5 746 513**	**5 915 775**	**1 468 047**	**8 342 412**	**3 782 835**	**633 406**	**56 747**	**58 830**

Centra Gas Manitoba Inc.
2013/14 General Rate Application - Reflecting Order 85/13
Allocation Results of Cost of Service Elements
2013/14 Test Year

Schedule 11.1.5
Page 1 of 6
July 31, 2013

Account Description	Account Code	Total Allocated Dollars	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Allocation Factor	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	
COST OF SERVICE DETAILS												
I. COST OF GAS												
A. FIXED COSTS		[redacted]		[redacted]			[redacted]					
TCPL FS Demand - Sask Zone												
TCPL STS Demand												
TCPL FS Demand - SSDA (Welwyn)												
TCPL FS Demand - SSDA (Welwyn) to Man Zone												
TCPL FS Demand - Man Zone												
ANR Storage Capacity												
ANR Storage Deliverability												
ANR Oklahoma Winter												
ANR Crystal Falls from Storage												
GLGT Winter												1a
Seasonal Storage Capacity												
Seasonal Storage Deliverability												
Annual Storage Capacity												
Annual Storage Deliverability												
ANR Joliet Summer												
ANR Crystal Falls to Storage												
GLGT Summer												
Forecast Capacity Management Revenues												
Sub-total												
B. VARIABLE TRANSPORTATION												
TCPL FS - Sask Zone												
TCPL FS - Flowing directly to Man Zone												
TCPL FS - SSDA (Welwyn)												
TCPL Firm Service - Emerson to Man Zone												
ANR Oklahoma to Crystall Falls												
ANR Storage Transportation												
Storage Withdrawl Chg.												
Storage Gas - Transportation & Delivery Cost												
Compressor Fuel: TCPL SSDA												1a
Compressor Fuel: TCPL MDA												
Compressor Fuel: Emerson												
Compressor Fuel: TCPL SSDA (Welwyn) to MDA												
Compressor Fuel: Oklahoma												
Compressor Fuel: Storage												
Sub-total												
C. COMMODITY COST												
Primary Direct to System												
Storage Gas: Primary to System												
Oklahoma Supply												
Storage Gas: Supplemental Supply												
Emerson Supply												1a
Delivered Service												
Fixed Price Offering												
Sub-total												
D. OTHER GAS COSTS												
Minell Charges												
Load Balancing Charges												
Baseload Volume Price Increment Charges												1a
Sub-total												
Total Cost of Gas		**199,771,646**		**0**	**199,771,646**		**21,978,946**	**3,687,468**	**25,666,414**	**18,434,647**	**4,146,973**	
II. OTHER REVENUE												
Rental Income		-31,103		0	-31,103		-29,042	-2,061	-31,103	0	0	
Late Payment Charge		-1,200,921		0	-1,200,921		-1,121,358	-79,562	-1,200,921	0	0	
Broker Revenue		-37,792		0	-37,792		-28,885	-2,883	-31,767	-5,053	-567	
Other		-595,745		0	-595,745		-418,802	-37,381	-456,183	-91,687	-20,325	
Total Other Revenue		**-1,865,560**		**0**	**-1,865,560**		**-1,598,087**	**-121,887**	**-1,719,974**	**-96,740**	**-20,893**	

Centra Gas Manitoba Inc.
2013/14 General Rate Application - Reflecting Order 85/13
Allocation Results of Cost of Service Elements
2013/14 Test Year

Schedule 11.1.5
Page 2 of 6
July 31, 2013

Account Description	Account Code	Total Allocated Dollars	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FPO	
COST OF SERVICE DETAILS												
I. COST OF GAS												
A. FIXED COSTS												
TCPL FS Demand - Sask Zone		[redacted]										
TCPL STS Demand												
TCPL FS Demand - SSDA (Welwyn)												
TCPL FS Demand - SSDA (Welwyn) to Man Zone												
TCPL FS Demand - Man Zone												
ANR Storage Capacity												
ANR Storage Deliverability												
ANR Oklahoma Winter												
ANR Crystal Falls from Storage												
GLGT Winter												
Seasonal Storage Capacity												1a
Seasonal Storage Deliverability												
Annual Storage Capacity												
Annual Storage Deliverability												
ANR Joliet Summer												
ANR Crystal Falls to Storage												
GLGT Summer												
Forecast Capacity Management Revenues												
Sub-total												
B. VARIABLE TRANSPORTATION												
TCPL FS - Sask Zone		[redacted]										
TCPL FS - Flowing directly to Man Zone												
TCPL FS - SSDA (Welwyn)												
TCPL Firm Service - Emerson to Man Zone												
ANR Oklahoma to Crystall Falls												
ANR Storage Transportation												
Storage Withdrawl Chg.												
Storage Gas - Transportation & Delivery Cost												
Compressor Fuel: TCPL SSDA												1a
Compressor Fuel: TCPL MDA												
Compressor Fuel: Emerson												
Compressor Fuel: TCPL SSDA (Welwyn) to MDA												
Compressor Fuel: Oklahoma												
Compressor Fuel: Storage												
Sub-total												
C. COMMODITY COST												
Primary Direct to System		[redacted]										
Storage Gas: Primary to System												
Oklahoma Supply												
Storage Gas: Supplemental Supply												1a
Emerson Supply												
Delivered Service												
Fixed Price Offering												
Sub-total												
D. OTHER GAS COSTS												
Minell Charges		[redacted]										
Load Balancing Charges												
Baseload Volume Price Increment Charges												1a
Sub-total												
Total Cost of Gas		**199,771,646**	**9,698**	**563,683**	[redacted]		**1,606,515**	[redacted]			**928,401**	1a, 2d
II. OTHER REVENUE												
Rental Income		-31,103	0	0	0	0	0	[redacted]			0	
Late Payment Charge		-1,200,921	0	0	0	0	0				0	
Broker Revenue		-37,792	-2	-50	-17	-81	-253				0	1e
Other		-595,745	-39	-6,306	-5,227	-936	-7,668				-1,110	
Total Other Revenue		**-1,865,560**	**-40**	**-6,357**	**-5,244**	**-1,017**	**-7,922**				**-1,110**	

Centra Gas Manitoba Inc.
2013/14 General Rate Application - Reflecting Order 85/13
Allocation Results of Cost of Service Elements
2013/14 Test Year

Account Description	Account Code	Total Allocated Dollars	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Allocation Factor	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF
III. OPERATING & MAINTENANCE EXPENSES											
A. PRESIDENT & CEO											
Audit		225,000		0	225,000		158,466	14,167	172,634	34,874	7,744
Liability Claims		82,000		0	82,000		57,752	5,163	62,915	12,709	2,822
Public Affairs		522,000		0	522,000		367,642	32,868	400,510	80,907	17,965
Research & Development		80,000		0	80,000		44,806	5,615	50,421	21,807	5,953
Sub-total		909,000		0	909,000		628,667	57,813	686,480	150,297	34,484
B. FINANCE & ADMINISTRATION											
IT - Banner		1,117,000		0	1,117,000		1,012,825	71,862	1,084,687	31,776	375
IT - Distribution/Metering		124,000		0	124,000		87,171	7,781	94,951	19,084	4,231
Gas Accounting		348,000		0	348,000		38,287	6,424	44,711	32,113	7,224
Gas Regulatory		1,988,000		0	1,988,000		1,397,540	124,742	1,522,282	305,958	67,826
Gas Supply		2,416,000		230,000	2,186,000		730,738	122,581	853,319	612,961	212,577
Treasury		318,000		0	318,000		223,550	19,954	243,504	48,941	10,849
Property Tax Administration		0		0	0		0	0	0	0	0
Sub-total		6,311,000		230,000	6,081,000		3,490,111	353,342	3,843,453	1,050,832	303,082
C. TRANSMISSION											
Communication Systems		197,000		0	197,000		32,921	5,507	38,428	27,598	80,007
Sub-total		197,000		0	197,000		32,921	5,507	38,428	27,598	80,007
D. POWER SUPPLY											
Environmental Management		412,000		0	412,000		206,898	26,762	233,660	107,717	29,611
Sub-total		412,000		0	412,000		206,898	26,762	233,660	107,717	29,611
E. CUSTOMER SERVICE & DISTRIBUTION											
Billing Inquiries & Collections		1,807,000		0	1,807,000		1,451,932	103,017	1,554,949	206,401	29,165
Customer Inspections		9,162,000		2,938,000	6,224,000		8,047,384	589,104	8,636,488	338,028	46,721
Customer Relations		1,531,000		0	1,531,000		1,388,000	98,000	1,486,000	44,000	1,000
Customer Safety		1,961,000		0	1,961,000		1,233,797	87,540	1,321,337	628,075	7,404
Distribution Maintenance		7,397,000		0	7,397,000		4,624,566	566,261	5,190,827	1,485,704	309,146
Dispatch		2,849,000		0	2,849,000		2,394,262	194,899	2,589,160	252,242	5,161
Station Maintenance		5,875,000		444,000	5,431,000		3,171,804	392,508	3,564,312	1,502,397	410,133
System Maintenance & Support		648,000		0	648,000		325,413	42,092	367,504	169,419	46,573
System Integrity		1,407,000		0	1,407,000		706,567	91,394	797,961	367,860	101,124
Meter Reading		2,056,000		0	2,056,000		1,571,723	189,580	1,761,303	277,768	10,236
Meter Changes		4,569,000		0	4,569,000		3,359,288	238,347	3,597,636	899,412	45,969
Sub-total		39,262,000		3,382,000	35,880,000		28,274,736	2,592,741	30,867,478	6,171,306	1,012,633
F. CUSTOMER CARE & MARKETING											
Customer Billing		8,542,000		1,894,000	6,648,000		6,951,597	568,403	7,519,999	854,055	107,299
Customer Relations		6,387,000		0	6,387,000		4,056,000	310,000	4,366,000	1,047,000	556,000
Customer Safety		314,000		0	314,000		197,559	14,017	211,576	100,569	1,185
Quality Assessment		576,000		0	576,000		355,971	43,802	399,773	116,835	24,610
Load Forecast		196,000		0	196,000		106,684	7,569	114,253	3,891	50,089
Meter Repair & Calibration		1,911,000		0	1,911,000		1,405,034	99,690	1,504,724	376,182	19,227
Sub-total		17,926,000		1,894,000	16,032,000		13,072,844	1,043,481	14,116,324	2,498,532	758,410
G. ADJUSTMENTS TO INCOME											
Corporate Alloc. & Adj.		6,845,000		0	6,845,000		4,811,953	429,506	5,241,459	1,053,463	233,535
Depreciation, Interest, Taxes		-3,062,000		0	-3,062,000		-2,152,550	-192,132	-2,344,682	-471,250	-104,468
Sub-total		3,783,000		0	3,783,000		2,659,404	237,373	2,896,777	582,213	129,067
Total Operating & Maintenance Expenses		**68,800,000**		**5,506,000**	**63,294,000**		**48,365,580**	**4,317,020**	**52,682,600**	**10,588,496**	**2,347,294**

Centra Gas Manitoba Inc.
2013/14 General Rate Application - Reflecting Order 85/13
Allocation Results of Cost of Service Elements
2013/14 Test Year

Schedule 11.1.5
Page 4 of 6
July 31, 2013

Account Description	Account Code	Total Allocated Dollars	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FPO	
III. OPERATING & MAINTENANCE EXPENSES												
A. PRESIDENT & CEO								[redacted]				
Audit		225,000	13	1,712	1,974	354	2,912				419	
Liability Claims		82,000	5	624	719	129	1,061				153	
Public Affairs		522,000	29	3,973	4,580	820	6,755				973	
Research & Development		80,000	0	0	0	0	1,819				0	1e
Sub-total		909,000	47	6,310	7,273	1,303	12,547				1,545	
B. FINANCE & ADMINISTRATION												
IT - Banner		1,117,000	0	0	0	0	163				0	
IT - Distribution/Metering		124,000	8	1,313	1,088	195	1,596				231	
Gas Accounting		348,000	17	982	162	217	2,799				1,617	
Gas Regulatory		1,988,000	129	21,044	17,442	3,124	25,590				3,704	1e
Gas Supply		2,416,000	334	119,912	97,323	35,179	90,813				2,450	
Treasury		318,000	21	3,366	2,790	500	4,093				592	
Property Tax Administration		0	0	0	0	0	0				0	
Sub-total		6,311,000	509	146,617	118,804	39,215	125,053				8,595	
C. TRANSMISSION												
Communication Systems		197,000	15	11,411	3,835	1,866	33,840				0	
Sub-total		197,000	15	11,411	3,835	1,866	33,840				0	1e
D. POWER SUPPLY												
Environmental Management		412,000	22	7,529	22,063	2,138	9,259				0	
Sub-total		412,000	22	7,529	22,063	2,138	9,259				0	1e
E. CUSTOMER SERVICE & DISTRIBUTION												
Billing Inquiries & Collections		1,807,000	317	2,536	317	634	12,680				0	
Customer Inspections		9,162,000	107	29,830	86,980	8,466	15,379				0	
Customer Relations		1,531,000	0	0	0	0	0				0	
Customer Safety		1,961,000	80	644	80	161	3,219				0	
Distribution Maintenance		7,397,000	294	98,899	195,411	18,937	97,781				0	
Dispatch		2,849,000	0	77	0	0	2,359				0	1e
Station Maintenance		5,875,000	815	270,053	0	3	127,286				0	
System Maintenance & Support		648,000	35	11,842	34,701	3,363	14,563				0	
System Integrity		1,407,000	76	25,712	75,345	7,302	31,620				0	
Meter Reading		2,056,000	0	1,063	133	266	5,231				0	
Meter Changes		4,569,000	500	3,997	500	999	19,987				0	
Sub-total		39,262,000	2,225	444,654	393,467	40,131	330,105				0	
F. CUSTOMER CARE & MARKETING												
Customer Billing		8,542,000	1,166	9,330	1,166	2,333	46,652				0	
Customer Relations		6,387,000	0	48,000	6,000	12,000	241,000				111,000	
Customer Safety		314,000	13	103	13	26	515				0	
Quality Assessment		576,000	25	8,264	17,049	1,652	7,793				0	1e
Load Forecast		196,000	0	4,356	544	1,089	21,778				0	
Meter Repair & Calibration		1,911,000	209	1,672	209	418	8,359				0	
Sub-total		17,926,000	1,413	71,725	24,982	17,517	326,097				111,000	
G. ADJUSTMENTS TO INCOME												
Corporate Alloc. & Adj.		6,845,000	445	72,459	60,054	10,757	88,109				12,754	
Depreciation, Interest, Taxes		-3,062,000	-199	-32,413	-26,864	-4,812	-39,414				-5,705	1e
Sub-total		3,783,000	246	40,045	33,190	5,945	48,695				7,048	
Total Operating & Maintenance Expenses		**68,800,000**	**4,477**	**728,291**	**603,614**	**108,116**	**885,596**				**128,188**	1e

Centra Gas Manitoba Inc.
2013/14 General Rate Application - Reflecting Order 85/13
Allocation Results of Cost of Service Elements
2013/14 Test Year

Account Description	Account Code	Total Allocated Do lars	Direct Assignment Factor	Total Direct Assignment	Balance to be Allocated	Allocation Factor	Residential SGS-R	Small Commercial SGS-C	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF
IV. DEPRECIATION & AMORTIZATION											
Depreciation Expense		18,036,419		0	18,036,419		11,098,520	1,603,772	12,702,292	3,826,932	644,366
Amortization of Cust. Contributions		-999,733		0	-999,733		-59,137	63,037	3,900	-237,883	-127,156
Depreciation: Common Assets		4,620,879		0	4,620,879		3,248,423	289,948	3,538,371	711,165	157,653
Amortization Expense (Deferreds)		1,234,802		100,000	1,134,802		679,012	96,726	775,738	247,064	47,069
Demand Side Management Amortization Expense (Deferred)		7,198,213		0	7,198,213		2,807,303	1,367,660	4,174,964	2,447,392	143,964
Furnace Replacement Program		3,800,000		0	3,800,000		3,800,000	0	3,800,000	0	0
Ex-Franchise Depreciation & Amortization		0		0	0		0	0	0	0	0
Total Depreciation & Amortization Expenses		**33,890,579**		**100,000**	**33,790,579**		**21,574,120**	**3,421,143**	**24,995,263**	**6,994,670**	**865,897**
V. CAPITAL & OTHER TAXES											
Municipal Taxes		11,187,000		0	11,187,000		6,693,772	953,534	7,647,306	2,435,585	464,016
Payroll Tax		807,000		0	807,000		567,311	50,637	617,949	124,199	27,533
Taxes on Common Assets		170,000		0	170,000		97,893	16,235	114,127	40,052	6,710
Corporate Capital Tax		2,516,000		0	2,516,000		1,448,811	240,274	1,689,084	592,768	99,303
Business Taxes		0		0	0		0	0	0	0	0
Other		0		0	0		0	0	0	0	0
Income Taxes		4,070,000		0	4,070,000		2,343,664	388,678	2,732,342	958,890	160,637
Total Taxes		**18,750,000**		**0**	**18,750,000**		**11,151,451**	**1,649,357**	**12,800,808**	**4,151,494**	**758,199**
VI. FINANCE EXPENSE		**16,945,000**		**0**	**16,945,000**		**9,828,243**	**1,617,181**	**11,445,423**	**3,943,774**	**654,071**
VII. CORPORATE ALLOCATION		**12,000,000**		**0**	**12,000,000**		**6,960,101**	**1,145,244**	**8,105,346**	**2,792,876**	**463,196**
VIII. NET INCOME (LOSS)		**3,000,000**		**0**	**3,000,000**		**1,740,025**	**286,311**	**2,026,336**	**698,219**	**115,799**
COST OF SERVICE SUMMARY											
COST OF GAS		199,771,646		0	199,771,646		21,978,946	3,687,468	25,666,414	18,434,647	4,146,973
OTHER REVENUE		-1,865,560		0	-1,865,560		-1,598,087	-121,887	-1,719,974	-96,740	-20,893
OPERATING EXPENSES											
President & CEO		909,000		0	909,000		628,667	57,813	686,480	150,297	34,484
Finance & Administration		6,311,000		230,000	6,081,000		3,490,111	353,342	3,843,453	1,050,832	303,082
Transmission		197,000		0	197,000		32,921	5,507	38,428	27,598	80,007
Power Supply		412,000		0	412,000		206,898	26,762	233,660	107,717	29,611
Customer Service & Distribution		39,262,000		3,382,000	35,880,000		28,274,736	2,592,741	30,867,478	6,171,306	1,012,633
Customer Care & Marketing		17,926,000		1,894,000	16,032,000		13,072,844	1,043,481	14,116,324	2,498,532	758,410
Adjustments to Income		3,783,000		0	3,783,000		2,659,404	237,373	2,896,777	582,213	129,067
Sub-total		68,800,000		5,506,000	63,294,000		48,365,580	4,317,020	52,682,600	10,588,496	2,347,294
DEPRECIATION & AMORTIZATION		33,890,579		100,000	33,790,579		21,574,120	3,421,143	24,995,263	6,994,670	865,897
CAPITAL & OTHER TAXES		18,750,000		0	18,750,000		11,151,451	1,649,357	12,800,808	4,151,494	758,199
FINANCE EXPENSE		16,945,000		0	16,945,000		9,828,243	1,617,181	11,445,423	3,943,774	654,071
CORPORATE ALLOCATION		12,000,000		0	12,000,000		6,960,101	1,145,244	8,105,346	2,792,876	463,196
NET INCOME		3,000,000		0	3,000,000		1,740,025	286,311	2,026,336	698,219	115,799
COST OF SERVICE		351,291,665		5,606,000	345,685,665		120,000,379	16,001,837	136,002,216	47,507,435	9,330,536

Centra Gas Manitoba Inc.
2013/14 General Rate Application - Reflecting Order 85/13
Allocation Results of Cost of Service Elements
2013/14 Test Year

Schedule 11.1.5
Page 6 of 6
July 31, 2013

Account Description	Account Code	Total Allocated Dollars	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	Fixed Price Offering FPO	
IV. DEPRECIATION & AMORTIZATION												
Depreciation Expense		18,036,419	1,008	213,112	335,667	94,807	215,915	[redacted]	[redacted]	[redacted]	349	
Amortization of Cust. Contributions		-999,733	-272	-78,975	-378,446	-134,363	-46,538	[redacted]	[redacted]	[redacted]	0	
Depreciation: Common Assets		4,620,879	301	48,915	40,541	7,261	59,480	[redacted]	[redacted]	[redacted]	8,610	
Amortization Expense (Deferreds)		1,234,802	62	14,667	28,906	5,854	15,442	[redacted]	[redacted]	[redacted]	100,000	
Demand Side Management Amortization Expense (Deferred)		7,198,213	0	287,929	0	0	143,964	[redacted]	[redacted]	[redacted]	0	1e
Furnace Replacement Program		3,800,000	0	0	0	0	0	[redacted]	[redacted]	[redacted]	0	
Ex-Franchise Depreciation & Amortization		0	0	0	0	0	0	[redacted]	[redacted]	[redacted]	0	
Total Depreciation & Amortization Expenses		**33,890,579**	**1,098**	**485,648**	**26,669**	**-26,441**	**388,264**	[redacted]	[redacted]	[redacted]	**108,959**	
V. CAPITAL & OTHER TAXES								[redacted]	[redacted]	[redacted]		
Municipal Taxes		11,187,000	607	144,586	284,961	57,706	152,233	[redacted]	[redacted]	[redacted]	0	
Payroll Tax		807,000	53	8,543	7,080	1,268	10,388	[redacted]	[redacted]	[redacted]	1,504	
Taxes on Common Assets		170,000	8	2,017	2,056	510	2,945	[redacted]	[redacted]	[redacted]	20	
Corporate Capital Tax		2,516,000	121	29,846	30,431	7,552	43,583	[redacted]	[redacted]	[redacted]	303	
Business Taxes		0	0	0	0	0	0	[redacted]	[redacted]	[redacted]	0	1e
Other		0	0	0	0	0	0	[redacted]	[redacted]	[redacted]	0	
Income Taxes		4,070,000	195	48,280	49,227	12,216	70,502	[redacted]	[redacted]	[redacted]	490	
Total Taxes		**18,750,000**	**984**	**233,271**	**373,756**	**79,252**	**279,650**	[redacted]	[redacted]	[redacted]	**2,316**	
VI. FINANCE EXPENSE		**16,945,000**	**808**	**199,087**	**204,951**	**50,860**	**289,022**	[redacted]	[redacted]	[redacted]	**2,038**	1e
VII. CORPORATE ALLOCATION		**12,000,000**	**572**	**140,988**	**145,141**	**36,018**	**204,677**	[redacted]	[redacted]	[redacted]	**1,443**	1e
VIII. NET INCOME (LOSS)		**3,000,000**	**143**	**35,247**	**36,285**	**9,004**	**51,169**	[redacted]	[redacted]	[redacted]	**361**	1e
COST OF SERVICE SUMMARY								[redacted]	[redacted]	[redacted]		
COST OF GAS		199,771,646	9,698	563,683	[redacted]	[redacted]	1,606,515	[redacted]	[redacted]	[redacted]	928,401	1a, 2d
OTHER REVENUE		-1,865,560	-40	-6,357	-5,244	-1,017	-7,922	[redacted]	[redacted]	[redacted]	-1,110	1e
OPERATING EXPENSES								[redacted]	[redacted]	[redacted]		
President & CEO		909,000	47	6,310	7,273	1,303	12,547	[redacted]	[redacted]	[redacted]	1,545	
Finance & Administration		6,311,000	509	146,617	118,804	39,215	125,053	[redacted]	[redacted]	[redacted]	8,595	
Transmission		197,000	15	11,411	3,835	1,866	33,840	[redacted]	[redacted]	[redacted]	0	
Power Supply		412,000	22	7,529	22,063	2,138	9,259	[redacted]	[redacted]	[redacted]	0	
Customer Service & Distribution		39,262,000	2,225	444,654	393,467	40,131	330,105	[redacted]	[redacted]	[redacted]	0	1e
Customer Care & Marketing		17,926,000	1,413	71,725	24,982	17,517	326,097	[redacted]	[redacted]	[redacted]	111,000	
Adjustments to Income		3,783,000	246	40,045	33,190	5,945	48,695	[redacted]	[redacted]	[redacted]	7,048	
Sub-total		68,800,000	4,477	728,291	603,614	108,116	885,596	[redacted]	[redacted]	[redacted]	128,188	
DEPRECIATION & AMORTIZATION		33,890,579	1,098	485,648	26,669	-26,441	388,264	[redacted]	[redacted]	[redacted]	108,959	1e
CAPITAL & OTHER TAXES		18,750,000	984	233,271	373,756	79,252	279,650	[redacted]	[redacted]	[redacted]	2,316	1e
FINANCE EXPENSE		16,945,000	808	199,087	204,951	50,860	289,022	[redacted]	[redacted]	[redacted]	2,038	1e
CORPORATE ALLOCATION		12,000,000	572	140,988	145,141	36,018	204,677	[redacted]	[redacted]	[redacted]	1,443	1e
NET INCOME		3,000,000	143	35,247	36,285	9,004	51,169	[redacted]	[redacted]	[redacted]	361	1e
COST OF SERVICE		351,291,665	17,741	2,379,859	[redacted]	[redacted]	3,696,972	[redacted]	[redacted]	[redacted]	1,170,596	1e

Centra Gas Manitoba Inc.
2013/14 GRA Rates Application - Reflecting Order 85/13
Gas & Non-Gas Components of Base Rates

Schedule 12.4.1
July 31, 2013

Line		Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Main Line Interruptible ML-INT
6	**August 1/13 Proposed Base Rates**									
8	BMC Rate	$14.00	$77.00	$1,221.42	$318.21	$1,247.13	$117,970.11	$8,026.07	$1,254.45	$1,247.13
10	*Demand*									
11	Transportation to Centra (Gas)			230.43	357.56	365.26	-	-	108.36	166.72
12	Transportation to Centra (Non-Gas)			8.16	12.66	12.93	-	-	3.84	5.90
13	Transportation to Centra (Total)			238.59	370.22	378.19	-	-	112.20	172.62
14	M3			0.2386	0.3702	0.3782	-	-	0.1122	0.1726
16	Distribution to Customer (Gas)			0.82	1.23	1.56	-	0.20	0.43	1.56
17	Distribution to Customer (Non-Gas)			165.78	129.77	180.22	-	4.28	84.66	180.22
18	Distribution to Customer (Total)			166.59	131.00	181.78	-	4.48	85.08	181.78
19	M3			0.1666	0.1310	0.1818	-	0.0045	0.0851	0.1818
21	*Commodity*									
22	Transportation to Centra (Gas)	36.36	35.57	12.94	2.22	2.64	-	-	7.02	2.72
23	Transportation to Centra (Non-Gas)	3.48	3.45	2.65	2.26	2.28	-	-	2.44	2.29
24	Transportation to Centra (Total)	39.84	39.02	15.59	4.48	4.93	-	-	9.46	5.00
25	M3	0.0398	0.0390	0.0156	0.0045	0.0049	-	-	0.0095	0.0050
27	Distribution to Customer (Gas)	1.36	1.33	1.23	-	1.20	0.15	8.01	1.93	1.20
28	Distribution to Customer (Non-Gas)	$92.95	$40.32	8.21	-	3.27	0.00	0.03	5.15	3.27
29	Distribution to Customer (Total)	94.31	41.65	9.44	-	4.47	0.15	8.05	7.08	4.47
30	M3	0.0943	0.0417	0.0094	0.0001	0.0045	0.0001	0.0081	0.0071	0.0045

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application Pre-hearing Update
Unit Cost Summary
Proposed Rates, November 1, 2015

Schedule 5.0.0
September 11, 2015

		System Total	Small Gen. Service SGS	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Primary Gas PG	Firm Supplemental FSP	Interruptible Supplemental ISP	
1	REVENUE REQU REMENTS - GAS COSTS ONLY													
2	Upstream Demand ($)	[redacted]												
3	Upstream Commodity ($)													
4	Upstream Customer ($)													
5	Upstream Total ($)													
6														
7	Downstream Demand ($)													1e
8	Downstream Commodity ($)													
9	Downstream Customer ($)													
10	Downstream Total ($)													
11														
12	Total ($)													
13														
14	MONTHLY B LLING DETERMINANTS	[redacted]												
15	Upstream Demand (10^3m^3-day)													
16	Upstream Commodity (10^3m^3)													
17	Upstream Customer (customers)													
18														1d
19	Downstream Demand (10^3m^3-day)													
20	Downstream Commodity (10^3m^3)													
21	Downstream Customer (customers)													
22														
23	PERCENT IN DEMAND CHARGE		0%	0%	65%	100%	100%	100%	100%	65%	100%	100%	100%	
24														
25	RESULT NG UNIT CHARGES													
26	Upstream Demand ($/$10^3m^3$-day)		-	-	301.207	458.252	534.634	-	-	140 015	-	-	-	
27	Upstream Commodity ($/$10^3m^3$)		46.755	44 605	14 689	1.099	1.411	-	-	6 848	-	155.082	154.686	
28	Upstream Customer ($/customer)													
29														
30	Downstream Demand ($/$10^3m^3$-day)		-	-	0.790	1.172	1.352	-	0.516	0.415	-	-	-	
31	Downstream Commodity ($/$10^3m^3$)		1 364	1 264	0 923	-	1.214	0.137	8.303	3.749	-	-	-	
32	Downstream Customer ($/customer)													

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application Pre-hearing Update
Unit Cost Summary
Existing Rates Approved by B/O 72/15

Schedule 5.1.0
September 11, 2015

	System Total	Small Gen. Service	Large Gen Service	High Volume	Cooperative	Main Line	Special Contracts	Power Stations	Interruptible	Primary Gas	Firm Supplemental	Interruptible Supplemental
1 REVENUE REQUIREMENTS - GAS COSTS ONLY												
2 Upstream Demand ($)	[redacted]											
3 Upstream Commodity ($)												
4 Upstream Customer ($)												
5 Upstream Total ($)												
6												
7 Downstream Demand ($)												
8 Downstream Commodity ($)												
9 Downstream Customer ($)												
10 Downstream Total ($)												
11												
12 Total ($)												
13												
14 MONTHLY BILLING DETERMINANTS												
15 Upstream Demand (10^3m^3-day)	[redacted]											
16 Upstream Commodity (10^3m^3)												
17 Upstream Customer (customers)												
18												
19 Downstream Demand (10^3m^3-day)												
20 Downstream Commodity (10^3m^3)												
21 Downstream Customer (customers)												
22												
23 PERCENT IN DEMAND CHARGE		0%	0%	65%	100%	100%	100%	100%	65%	100%	100%	100%
24												
25 RESULTING UNIT CHARGES												
26 Upstream Demand ($/$10^3m^3$-day)		-	-	230.428	357.559	365.257	-	-	108.365	-	-	-
27 Upstream Commodity ($/$10^3m^3$)		36.356	35.567	12.944	2.218	2.643	-	-	7.023	-	159.290	169.721
28 Upstream Customer ($/customer)												
29												
30 Downstream Demand ($/$10^3m^3$-day)		-	-	0.815	1.226	1.560	-	0.203	0.426	-	-	-
31 Downstream Commodity ($/$10^3m^3$)		1.363	1.330	1.226	-	1.197	0.147	8.013	1.932	-	-	-
32 Downstream Customer ($/customer)												

1e

1d

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application Pre-hearing Update
Functionalization of Gas Costs

Schedule 5.2.0
September 11, 2015

Line		Net Change	Current 2012/13	Proposed 2015/16	Functionalization Direct	Functionalization Allocator	To be Allocated	Production	Pipeline	Storage	Transmission	Distribution	OnSite	Total	
3															
4															
5	A. FIXED COSTS														
6	TCPL & Others CD Demand	[redacted]													
7	TCPL STS Demand														
8	Storage Capacity/Deliverability														
9	US Pipelines Demand														1e
10	Load Balancing Charges														
11	Capacity Management Revenues														
12	Other														
13	Subtotal - FIXED COSTS														
14															
15	B. VARIABLE TRANSPORTATION														
16	TCPL Transportation	[redacted]													
17	US Pipelines Transportation &Comp														
18	Storage Withdrawal														1e
19	Compressor fuel for Primary Gas														
20	Subtotal - VARIABLE TRANSPORTATION														
21															
22															
23															
24	C. COMMODITY COST														
25	Western Canadian Supplies	[redacted]													
26	Supplemental Gas														
27	Storage														1e
28	Other														
29	Subtotal - COMMODITY COST														
30															
31	TOTAL COST OF GAS														

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application Pre hearing Update
Classification of Gas Costs

Schedule 5.3.0
September 11, 2015

Classificatid

		Classification			Production		Pipeline		Storage		Transmission		Distribution		OnSite		Total		
2		$ A located	Allocator	$ Direct	Capacity	Commodity	Capacity	Commodity	Capacity	Commodity	Capacity	Commodity	Capacity	Commodity	Capacity	Commodity	Capacity	Commodity	
3																			
4	A. FIXED COSTS																		
5	TCPL CD Demand	[redacted]	DEMAND	[redacted]															
6	TCPL STS Demand		DEMAND																
7	Storage Capacity		DEMAND																
8	US Pipelines Demand		DEMAND																
9	Load Balancing Charges		DEMAND																1e
10	Capacity Management Revenues		DEMAND																
11	Other		DEMAND																
12	Subtotal - FIXED COSTS																		
13																			
14	B. VARIABLE TRANSPORTATION																		
15	TCPL Transportation		ENERGY	[redacted]															
16	US Pipelines Transportation		ENERGY																1e
17	Storage Withdrawal		ENERGY																
18	TCPL Compressor		ENERGY																
19	Subtotal - VARIABLE TRANSPORTATION																		
20																			
21																			
22																			
23	C. COMMODITY COST																		
24	Western Canadian Supplies		ENERGY	[redacted]															
25	Arkoma		ENERGY																
26	Storage		ENERGY																1e
27	Other		ENERGY																
28	Subtotal - COMMODITY COST																		
29																			
30	TOTAL COST OF GAS																		

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application Pre hearing Update
Allocation of Production Capacity Costs

Schedule 5.4.0
September 11, 2015

Allocation of Production Capacity Costs:

1			Capacity								Special						Total	
2		$ Allocated	Allocator	$ Direct	SGS	LGS	HVF	Co-op	Mainline	Interruptible	Contract	Power Stations	Primary	Supp - Firm	Supp - Int	Other	Capacity	
3																		
4																		
5	A. FIXED COSTS	[redacted]																
6	TCPL CD Demand																	
7	TCPL STS Demand																	
8	Storage Capacity																	
9	US Pipelines Demand																	1e
10	Load Balancing Charges																	
11	Capacity Management Revenues																	
12	Other																	
13	Subtotal - FIXED COSTS																	
14																		
15	B. VARIABLE TRANSPORTATION																	
16	TCPL Transportation																	
17	US Pipelines Transportation																	1e
18	Storage Withdrawal																	
19	TCPL Compressor																	
20	Subtotal - VARIABLE TRANSPORTATION																	
21																		
22																		
23																		
24	C. COMMODITY COST																	
25	Western Canadian Supplies																	
26	Arkoma																	
27	Storage																	1e
28	Other																	
29	Subtotal - COMMODITY COST																	
30																		
31	TOTAL COST OF GAS																	

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application Pre hearing Update
Allocation of Production Commodity Costs

Schedule 5.4.1
September 11, 2015

Allocation of Production Commodity Costs:

Line	Description	$ Allocated	Commodity Allocator	$ Direct	SGS	LGS	HVF	Co-op	Mainline	Interruptible	Special Contract	Power Stations	Primary	Supp - Firm	Supp - Int	Other	Total Commodity	
1																		
2																		
3																		
4																		
5	A. FIXED COSTS	[redacted]																
6	TCPL CD Demand																	
7	TCPL STS Demand																	
8	Storage Capacity																	
9	US Pipelines Demand																	
10	Load Balancing Charges																	1e
11	Capacity Management Revenues																	
12	Other																	
13	Subtotal - FIXED COSTS																	
14																		
15	B. VARIABLE TRANSPORTATION																	
16	TCPL Transportation																	
17	US Pipelines Transportation																	
18	Storage Withdrawal																	1e
19	TCPL Compressor																	
20	Subtotal - VARIABLE TRANSPORTATION																	
21																		
22																		
23																		
24	C. COMMODITY COST																	
25	Western Canadian Supplies																	
26	Arkoma																	
27	Storage																	
28	Other																	1e
29	Subtotal - COMMODITY COST																	
30																		
31	TOTAL COST OF GAS																	

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application Pre hearing Update
Allocation of Pipeline Capacity Costs

Schedule 5.4.2
September 11, 2015

Allocation of Pipeline Capacity Costs:

		$ Allocated	Capacity Factor	$ Direct	SGS	LGS	HVF	Co-op	Mainline	Interruptible	Special Contract	Power Stations	Primary	Supp - Firm	Supp - Int	Other	Total Capacity	
1																		
2																		
3																		
4																		
5	A. FIXED COSTS																	
6	TCPL CD Demand	[redacted]																
7	TCPL STS Demand																	
8	Storage Capac ty																	
9	US Pipelines Demand																	
10	Load Balancing Charges																	1e
11	Capacity Management Revenues																	
12	Other																	
13	Subtotal - FIXED COSTS																	
14																		
15	B. VARIABLE TRANSPORTATION																	
16	TCPL Transportation																	
17	US Pipelines Transportation																	1e
18	Storage Withdrawal																	
19	Other																	
20	Subtotal - VARIABLE TRANSPORTATION																	
21																		
22																		
23																		
24	C. COMMODITY COST																	
25	Western Canadian Supplies																	
26	Arkoma																	
27	Storage																	1e
28	Other																	
29	Subtotal - COMMODITY COST																	

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application Pre hearing Update
Allocation of Pipeline Commodity Costs

Schedule 5.4.3
September 11, 2015

Allocation of Pipeline Commodity Costs:

			Commodity								Special	Power					Total	
1																		
2		$ Allocated	Factor	$ Direct	SGS	LGS	HVF	Co-op	Mainline	Interruptible	Contract	Stations	Primary	Supp - Firm	Supp - Int	Other	Commodity	
3																		
4																		
5	A. FIXED COSTS	[redacted]																
6	TCPL CD Demand																	
7	TCPL STS Demand																	
8	Storage Capac ty																	
9	US Pipelines Demand																	
10	Load Balancing Charges																	1e
11	Capacity Management Revenues																	
12	Other																	
13	Subtotal - FIXED COSTS																	
14																		
15	B. VARIABLE TRANSPORTATION																	
16	TCPL Transportation																	
17	US Pipelines Transportation																	
18	Storage Withdrawal																	1e
19	Other																	
20	Subtotal - VARIABLE TRANSPORTATION																	
21																		
22																		
23																		
24	C. COMMODITY COST																	
25	Western Canadian Supplies																	
26	Arkoma																	
27	Storage																	1e
28	Other																	
29	Subtotal - COMMODITY COST																	

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application Pre hearing Update
Allocation of Storage Capacity Costs

Schedule 5.4.4
September 11, 2015

Allocation of Storage Capacity Costs:

		$ Allocated	Capacity Factor	$ Direct	SGS	LGS	HVF	Co-op	Mainline	Interruptible	Special Contract	Power Stations	Primary	Supp - Firm	Supp - Int	Other	Total Capacity	
1																		
2																		
3																		
4																		
5	A. FIXED COSTS	[redacted]																
6	TCPL CD Demand																	
7	TCPL STS Demand																	
8	Storage Capac ty																	
9	US Pipelines Demand																	1e
10	Load Balancing Charges																	
11	Capacity Management Revenues																	
12	Other																	
13	Subtotal - FIXED COSTS																	
14																		
15	B. VARIABLE TRANSPORTATION																	
16	TCPL Transportation																	
17	US Pipelines Transportation																	
18	Storage Withdrawal																	1e
19	Other																	
20	Subtotal - VARIABLE TRANSPORTATION																	
21																		
22																		
23																		
24	C. COMMODITY COST																	
25	Western Canadian Supplies																	
26	Arkoma																	
27	Storage																	1e
28	Other																	
29	Subtotal - COMMODITY COST																	

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application Pre hearing Update
Allocation of Storage Commodity Costs

Schedule 5.4.5
September 11, 2015

Allocation of Storage Commodity Costs:

Line		Commodity									Special	Power					Total	
2		$ Allocated	Factor	$ Direct	SGS	LGS	HVF	Co-op	Mainline	Interruptible	Contract	Stations	Primary	Supp - Firm	Supp - Int	Other	Commodity	
3																		
4																		
5	A. FIXED COSTS	[redacted]																
6	TCPL CD Demand																	
7	TCPL STS Demand																	
8	Storage Capacity																	
9	US Pipelines Demand																	
10	Load Balancing Charges																	1e
11	Capacity Management Revenues																	
12	Other																	
13	Subtotal - FIXED COSTS																	
14																		
15	B. VARIABLE TRANSPORTATION																	
16	TCPL Transportation																	
17	US Pipelines Transportation																	
18	Storage Withdrawal																	1e
19	Other																	
20	Subtotal - VARIABLE TRANSPORTATION																	
21																		
22																		
23																		
24	C. COMMODITY COST																	
25	Western Canadian Supplies																	
26	Arkoma																	
27	Storage																	1e
28	Other																	
29	Subtotal - COMMODITY COST																	

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application Pre hearing Update
Allocation of Transmission Capacity Costs

Schedule 5.4.6
September 11, 2015

Allocation of Transmission Capacity Costs:

			Capacity								Special	Power					Total	
1																		
2		$ Allocated	Factor	$ Direct	SGS	LGS	HVF	Co-op	Mainline	Interruptible	Contract	Stations	Primary	Supp - Firm	Supp - Int	Other	Capacity	
3																		
4																		
5	A. FIXED COSTS	[redacted]																
6	TCPL CD Demand																	
7	TCPL STS Demand																	
8	Storage Capacity																	
9	US Pipelines Demand																	1e
10	Load Balancing Charges																	
11	Capacity Management Revenues																	
12	Other																	
13	Subtotal - FIXED COSTS																	
14																		
15	B. VARIABLE TRANSPORTATION																	
16	TCPL Transportation																	
17	US Pipelines Transportation																	
18	Storage Withdrawal																	1e
19	Other																	
20	Subtotal - VARIABLE TRANSPORTATION																	
21																		
22																		
23																		
24	C. COMMODITY COST																	
25	Western Canadian Supplies																	
26	Arkoma																	
27	Storage																	1e
28	Other																	
29	Subtotal - COMMODITY COST																	

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Application Pre hearing Update
Allocation of Transmission Commodity Costs

Schedule 5.4.7
September 11, 2015

Allocation of Transmission Commodity Costs:

		Commodity									Special	Power					Total	
1		$ Allocated	Factor	$ Direct	SGS	LGS	HVF	Co-op	Mainline	Interruptible	Contract	Stations	Primary	Supp - Firm	Supp - Int	Other	Commodity	
2																		
3																		
4																		
5	A. FIXED COSTS																	
6	TCPL CD Demand	[redacted]																
7	TCPL STS Demand																	
8	Storage Capac ty																	
9	US Pipelines Demand																	
10	Load Balancing Charges																	1e
11	Capacity Management Revenues																	
12	Other																	
13	Subtotal - FIXED COSTS																	
14																		
15	B. VARIABLE TRANSPORTATION																	
16	TCPL Transportation																	
17	US Pipelines Transportation																	
18	Storage Withdrawal																	1e
19	Other																	
20	Subtotal - VARIABLE TRANSPORTATION																	
21																		
22																		
23																		
24	C. COMMODITY COST																	
25	Western Canadian Supplies																	
26	Arkoma																	1e
27	Storage																	
28	Other																	
29	Subtotal - COMMODITY COST																	

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Appliciation Pre-hearing Update
Non-Gas & Gas Components of Base Rates - Approved Base Rates

Schedule 6.3.0
September 11, 2015

	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Main Line Interruptible ML-INT
August 1, 2015 Approved Rates									
BMC Rate	$14.00	$77.00	$1,221.42	$318.21	$1,247.13	$117,970.11	$8,026.07	$1,254.45	$1,247.13
Demand									
Transportation to Centra (Gas)			230.43	357.56	365.26	-	-	108.36	166.72
Transportation to Centra (Non-Gas)			8.16	12.66	12.93	-	-	3.84	5.90
Transportation to Centra (Total)			238.59	370.22	378.19	-	-	112.20	172.62
M3			0.2386	0.3702	0.3782	-	-	0.1122	0.1726
Distribution to Customer (Gas)			0.82	1.23	1.56	-	0.20	0.43	1.56
Distribution to Customer (Non-Gas)			165.78	129.77	180.22	-	4.28	84.66	180.22
Distribution to Customer (Total)			166.59	131.00	181.78	-	4.48	85.08	181.78
M3			0.1666	0.1310	0.1818	-	0.0045	0.0851	0.1818
Commodity									
Transportation to Centra (Gas)	36.36	35.57	12.94	2.22	2.64	-	-	7.02	2.72
Transportation to Centra (Non-Gas)	3.48	3.45	2.65	2.26	2.28	-	-	2.44	2.29
Transportation to Centra (Total)	39.84	39.02	15.59	4.48	4.93	-	-	9.46	5.00
M3	0.0398	0.0390	0.0156	0.0045	0.0049	-	-	0.0095	0.0050
Distribution to Customer (Gas)	1.36	1.33	1.23	-	1.20	0.15	8.01	1.93	1.20
Distribution to Customer (Non-Gas)	92.95	40.32	8.21	-	3.27	0.00	0.03	5.15	3.27
Distribution to Customer (Total)	94.31	41.65	9.44	-	4.47	0.15	8.05	7.08	4.47
M3	0.0943	0.0416	0.0094	0.0001	0.0045	0.0001	0.0080	0.0071	0.0045

Demand charges for SC class included in BMC charge.
2,560.165 Gas cost included in BMC for SC

Centra Gas Manitoba Inc.
2015/16 Cost of Gas Appliciation Pre-hearing Update
Non-Gas & Gas Components of Base Rates - Proposed Base Rates

Schedule 6.4.0
September 11, 2015

	Small Gen. Service SGS-Total	Large Gen Service LGS	High Volume HVF	Cooperative CO-OP	Main Line ML	Special Contracts SC	Power Stations GS	Interruptible INT	Main Line Interruptible ML-INT
November 1, 2015 Proposed Rates									
BMC Rate	$14.00	$77.00	$1,221.42	$318.21	$1,247.13	$117,914.17	$8,026.07	$1,254.45	$1,247.13
Demand									
Transportation to Centra (Gas)			301.21	458.25	534.63	-	-	140.01	215.41
Transportation to Centra (Non-Gas)			8.16	12.66	12.93	-	-	3.84	5.90
Transportation to Centra (Total)			309.37	470.91	547.57	-	-	143.85	221.31
M3			0.3095	0.4708	0.5476	-	-	0.1439	0.2213
Distribution to Customer (Gas)			0.79	1.17	1.35	-	0.52	0.42	1.35
Distribution to Customer (Non-Gas)			165.78	129.77	180.22	-	4.28	84.66	180.22
Distribution to Customer (Total)			166.57	130.95	181.57	-	4.79	85.07	181.57
M3			0.1666	0.1310	0.1816	-	0.0048	0.0851	0.1816
Commodity									
Transportation to Centra (Gas)	46.75	44.60	14.69	1.10	1.41	-	-	6.85	1.51
Transportation to Centra (Non-Gas)	3.48	3.45	2.65	2.26	2.28	-	-	2.44	2.29
Transportation to Centra (Total)	50.23	48.06	17.34	3.36	3.69	-	-	9.29	3.80
M3	0.0501	0.0480	0.0174	0.0034	0.0037	-	-	0.0094	0.0038
Distribution to Customer (Gas)	1.36	1.26	0.92	-	1.21	0.14	8.30	3.75	1.21
Distribution to Customer (Non-Gas)	92.95	40.32	8.21	-	3.27	0.00	0.03	5.15	3.27
Distribution to Customer (Total)	94.31	41.58	9.14	-	4.49	0.14	8.34	8.90	4.49
M3	0.0943	0.0416	0.0090	0.0001	0.0045	0.0001	0.0082	0.0089	0.0045

Demand charges for SC class included in BMC charge.
2,504 223 Gas cost included in BMC for SC

REFERENCE:

Application pp. 33, 38-40 of 40; 2019/20 GRA Exhibit Centra-33 (Centra Rebuttal) p. 8

PREAMBLE TO IR (IF ANY):

Figure 10 of Centra's Application presents the (illustrative) Revenue Requirement allocations to each of Centra's existing customer classes using both the currently approved COSS methodology and Centra's proposed COSS methodology changes.

Figure 11 of Centra's Application presents (illustrative) changes in non-gas cost allocations for both the currently approved COSS methodology and a possible Interim rate relief measure for the Special Contract class.

Application, p. 33: "Centra notes that the Selkirk Power Station is no longer part of the transmission grid and the assets associated with generating power were retired on March 31, 2021"

Page 8 of Centra's Rebuttal Evidence in the 2019/20 GRA (ex. Centra-33) states: "It is not clear to Centra if Ms. Derksen is proposing the re-imposition of the Minimum Margin Guarantee for the Power Stations class, which she describes as an interim offset of transmission related costs, as a bill mitigation measure. If the PUB were to consider this proposal as a means to provide bill mitigation to other customer classes or for any other purpose, customers in the Power Stations class would experience effectively a 500.2% bill increase. For proper comparison purposes to the analysis provided above, if Centra's commodity cost of gas is included in the calculation this increase would be 115.1%. This customer class did not have any notice of such a proposed impact and the issue of bill mitigation for this customer class would clearly become an issue."

QUESTION:

a) Further explain Centra's implementation plans regarding how the revenue deficiency created by the interim relief provided to the Special Contract Class would be absorbed by the Power Station Class should this option be approved. For example, would the resulting Special Contract Class revenue deficiency be added to the Power Stations Basic Monthly Charge?

b) Please provide the bill impact in dollar and percentage terms for the Power Station class, and, if different, the Power Station customer following the decommissioning of the Selkirk generating station. Also confirm whether Manitoba Hydro has been consulted and been provided sufficient notice of this proposal.

c) Given Centra's submission that the Selkirk Generating Station is now retired, and the typically intermittent operation of the Brandon Generating Station, discuss the risks (and associated risk mitigation plans) of insufficient recovery of the revenue deficiency resulting from the Special Contract Class interim proposal, which could ultimately impact Centra's net income until such time as non-gas rates are further reviewed at a future GRA.

RESPONSE:

Response to parts a) through c):

Centra proposes to recover the revenue deficiency of the interim relief to the Special Contract customer through an annual lump sum payment calculated and recovered from the remaining Power Station customer until new rates reflecting the updated cost allocation methodology are implemented following the next GRA. The charge would be calculated based on the approved (2019/20 GRA) non-gas cost allocated to the Power Station class, plus an interim deficiency adder compared to actual billed non-gas revenue for the customer.

Lump Sum payment = Approved non-gas costs allocated to Power Station Class + Interim Proposal – actual Billed non-gas Revenue

Utilizing, this mechanism removes any risk of revenue deficiency and ensures Centra's net income is not impacted by the interim proposal for the Special Contract Class. The bill impact to the Power Station customer would be dependent on the usage of the Power Station class as well as the effective date of the interim proposal. Based on the historic usage of the last few years Centra expects the impact to be in the range of $500-800 thousand. As Manitoba Hydro's and Centra's operations are fully integrated, and share a common governance structure, leadership team, enterprise planning process, as well as policies and practices, the potential impact of the proposed method was considered from an enterprise perspective.

REFERENCE:

MFR 9; Application pp.5 and 6 of 40; 2017/18 & 2018/19 Manitoba Hydro GRA Tab 9 p.2 of 18

PREAMBLE TO IR (IF ANY):

MFR 9 states that Centra's ratemaking goals and objectives are discussed in Section 2.1 of the Application.

Manitoba Hydro's ratemaking objectives are enumerated at page 2 of 18 in Tab 9 of the 2017/18 & 2018/19 GRA:

"1. Recovery of Revenue Requirement Rates must provide the Corporation the opportunity to fully recover its allowed revenue requirement.
2. Fairness and Equity Rate design should provide for equitable treatment of customers both within a customer class (whereby similar customers receive similar treatment) and between customer classes (whereby dissimilar customers may be treated differently).
3. Rate Stability and Gradualism In conformity with the principles of gradualism and sensitivity to customer impacts, annual adjustments to revenues by customer class should be less than two percentage points greater than the overall proposed increase.
4. Efficiency Manitoba Hydro views this goal in designing rates as the need to provide appropriate price signals regarding the value of energy and to promote the efficient and economic use of energy. The determination of an appropriate price signal may recognize the application of marginal cost considerations.
5. Competitiveness of Rates – Maintain Manitoba Hydro's competitive position with respect to rates charged by other Canadian utilities for all rate classes.
6. Simplicity and Understandability Rate design should be understandable to customers and should be easy to interpret and apply."

QUESTION:

Please confirm whether any or all of the Manitoba Hydro ratemaking objectives are shared by Centra. Also clarify any differences in objectives between Centra and Manitoba Hydro.

RESPONSE:

Centra notes that ratemaking objectives are pertinent at the rate making stage and the relative weight given to an objective or the reliance may change or adapt depending on the circumstances at the time of the rate proposal. With that context in mind Centra's objectives would typically be consistent with the listed objectives 1,2,4, 5 and 6.

Given the fact that natural gas rates have far more inherent volatility than electricity rates, Centra has not employed ceilings on rate differentials as defined in objective 3. The volatility in natural gas rates can result in either decreases or increases to rates and is largely driven by volatility of natural gas prices in the upstream natural gas market but can also include other contributing factors such as rate riders included in customers' billed rates.

REFERENCE:

Appendix 1 Atrium Report p. 22; Appendix 3; Appendix 4 p. 11 of 16

PREAMBLE TO IR (IF ANY):

At Appendix 1 p. 22, Atrium states: “The following are summary descriptions of the development of allocation methods by Centra for various O&M, Customer Service and Administrative expenses. Atrium found the analyses supporting the allocation methods to reflect a thorough representation of the underlying functions, responsibilities, and activities of the cost categories. […] Customer Contact Center – Costs are directly assigned to the customer classes based on estimated call volumes by class.”

Customer Contact Centre costs do not appear as a separate item in the Centra representative COSS allocation results included in Appendix 4 of Centra’s Application. Similarly, the CNTCTCNTR allocation factor, which is associated with Customer Contact Centre costs was also not identified in pages 15 to 32 of Appendix 3 of Centra’s Application.

QUESTION:

Please explain which Appendix 3 and Appendix 4 Cost of Service element would apply to Centra’s ongoing “Customer Contact Center”.

RESPONSE:

Customer Contact Centre costs are included in the Billing & Collection program costs that appear in both the Appendix 4 and Appendix 3 of the Application under the Operating and Administrative costs section. A portion of the Billing & Collections program costs associated with the Customer Contact Centre is directly assigned to each class using the CNTCTCNTR allocation factor. The remaining balance of the program is allocated using BILLCOLL allocation factor.