Manitoba Hydro

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May 7, 2013

PUBLIC UTILITIES BOARD OF MANITOBA
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

ATTENTION: Mr. H. M. Singh, Board Secretary and Executive Director

Dear Mr. Singh:

Re: Centra Gas Manitoba Inc. ("Centra")
2013/14 General Rate Application – Responses to Round 2 Information Requests & Revised Round 1 Information Requests

Enclosed please find Centra's responses to Round 2 Information Requests with respect to its 2013/14 General Rate Application from the Public Utilities Board ("PUB"), the Consumers Association of Canada (Manitoba) ("CAC"), and Just Energy Manitoba L.P. ("JEMLP").

The following Round 1 Information Requests have been revised.
PUB/Centra I-3(d)
PUB/Centra I-23(c)

PUB/Centra I-3(d) requests the total corporate cost of the management represented in the Organization Chart and the amount allocated to Centra. Centra inadvertently included additional costs, besides the cost of the management, in the response filed on April 16, 2013. The information has been corrected in the revised response. The response to PUB/Centra I-23(c) incorrectly included common area maintenance and taxes in both the Leasehold Rentals line and the Building & Property Services line. This has been revised and a small correction has been made to Building Property & Taxes. Please replace these Information Requests with the revised copies enclosed.

Manitoba Hydro is in the process of finalizing the Low Income Energy Efficiency evaluation plan and will file it with the PUB next week. Centra will file the responses to CAC/Centra II-68, CAC/Centra II-78(c), and CAC/Centra II-78(d) at that time.

Centra continues to prepare responses to the Round 1 Information Requests that were addressed by the PUB in its letter of May 2, 2013, and will file the responses as they become available.

Should you have any questions with respect to this submission, please contact the writer at 204-360-3468 or Greg Barnlund at 204-360-5243.

Yours truly,

MANITOBA HYDRO LAW DEPARTMENT
Per:

M Boyd

Marla D. Boyd
Barrister and Solicitor

cc: Mr. B. Peters, Fillmore Riley
Mr. R. Cathcart, Cathcart Advisors Inc.
Mr. B. Ryall, Ryall Engineering
Registered Interveners

Manitoba Hydro

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May 14, 2013

PUBLIC UTILITIES BOARD OF MANITOBA
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

ATTENTION: Mr. H. M. Singh, Board Secretary and Executive Director

Dear Mr. Singh:

Re: Centra Gas Manitoba Inc. ("Centra")
2013/14 General Rate Application –Remaining Round 2 Information Requests

Please find attached nine (9) copies of Centra's responses to the remaining Round 2 Information Requests with respect to the 2013/14 General Rate Application from the Consumers Association of Canada (Manitoba) ("CAC"):
CAC/Centra II-68
CAC/Centra II-78(c)
CAC/Centra II-78(d)

The Low Income Energy Efficiency Evaluation Plan can be found as an attachment to response to Information Request CAC/Centra II-68.

Please also find enclosed a replacement front and spine covers for the Round 2 Information Requests binder (Volume 6).

Centra continues to prepare responses to Round 1 Information Requests which the PUB directed be responded to in its letter of May 2, 2013. The volume of information requested in the outstanding Round 1 CAC questions is substantial (there are approximately 60 subparts to these questions) and will require some time to complete. Centra will endeavour to answer as soon as possible, but does not anticipate being in a position to file all of these responses until approximately May 24, 2013.

Copies of this letter and responses to the remaining Round 2 Information Requests have also been provided to the PUB Advisors and all registered interveners. Should you have any questions with respect to this submission, please contact the writer at 204-360-3468 or Greg Barnlund at 204-360-5243.

Yours truly,
MANITOBA HYDRO LAW DEPARTMENT
Per:

M Boyd

Marla D. Boyd
Barrister and Solicitor

cc: Mr. B. Peters, Fillmore Riley
Mr. R. Cathcart, Cathcart Advisors Inc.
Mr. B. Ryall, Ryall Engineering
Registered Interveners

PUB/CENTRA II-138

Reference: PUB/Centra I-1(a)

Please re-file the table in PUB/Centra I-1(a) showing the non-gas revenue and the requested and approved non-gas revenue increases. In instances where Centra did not specifically request a non-gas revenue increase, please translate the requested general revenue increase to a non-gas revenue increase.

ANSWER:

Please see the table below.

Approved Revenue Requirement and Requested and Approved Non-Gas Costs Compared to Manitoba CPI

Year	Date	Order	Approved Revenue Requirement ($000's)	Requested Rate Increase	Approved General Increase	Cumulative General Increase	Non-gas Costs Requested ($000's)[1]	Non-gas Costs Requested Annual Increase	Non-gas Costs Requested Cumulative Increase	Non-gas Costs Approved ($000's)[1]	Non-gas Costs Approved Annual Increase	Non-gas Costs Approved Cumulative Increase	CPI[2]	Cumulative CPI[2]
2003/04	1-Aug-03	118/03	498,788	3.0%	1.9%	1.9%	125,334			120,284			0.9%	0.9%
2004/05	No Rate Change		n/a	0.0%	0.0%	1.9%	n/a	n/a	n/a	n/a	n/a	n/a	2.7%	3.6%
2005/06	1-Aug-05	103/05	554,947	2.5%	2.0%	3.9%	129,542	3.4%	3.4%	126,401	5.1%	5.1%	2.4%	6.1%
2006/07	1-May-06	103/05	564,104	2.5%	1.0%	5.0%	142,672	10.1%	13.8%	131,223	3.8%	9.1%	2.0%	8.2%
2007/08	1-Aug-07	99/07	542,617	2.0%	2.0%	7.1%	137,699	-3.5%	9.9%	135,448	3.2%	12.6%	1.9%	10.3%
2008/09	1-May-08	99/07	550,171	1.0%	1.0%	8.1%	143,029	3.9%	14.1%	139,229	2.8%	15.8%	2.2%	12.7%
2009/10	No Rate Change	128/09	n/a	1.0%	0.0%	8.1%	145,241	1.5%	15.9%	n/a	0.0%	15.8%	0.6%	13.4%
2010/11	1-May-10	128/09	478,476	1.0%	0.8%	9.0%	155,776	7.3%	24.3%	143,083	2.8%	19.0%	1.0%	14.5%
2011/12	No Rate Change		n/a	0.0%	0.0%	9.0%	n/a	0.0%	24.3%	n/a	0.0%	19.0%	2.8%	17.7%
2012/13	No Rate Change		n/a	0.0%	0.0%	9.0%	n/a	0.0%	24.3%	n/a	0.0%	19.0%	1.7%	19.7%
2013/14[3]	Proposed August 1, 2013		n/a	2.0%		11.2%	150,679	-3.3%	20.2%	150,679	5.3%	25.3%	1.8%	21.9%

[1] Annualized Non-gas Costs Requested and Approved include operating expenses, depreciation & amortization, capital & other taxes, finance expense, net income, less other revenue.

[2] Forecast of CPI for 2013/14

[3] Proposed Non-gas Costs included for Requested and Approved for 2013/14

PUB/CENTRA II-139

Reference: PUB/Centra I-2(a) CGM12

Please re-file CGM12 on a similar basis as the response to PUB/Centra I 2(a) for the ten year forecast.

ANSWER:

The table below depicts CGM12 for the ten year forecast in a similar fashion as the response to PUB/Centra I-2(a).

(in millions of $)	Forecast 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
General Consumers Revenue										
- at approved rates	$ 322	$ 316	$ 360	$ 351	$ 349	$ 348	$ 349	$ 349	$ 350	$ 350
Furnace Replacement Program	(4)	(4)	(4)	-	-	-	-	-	-	-
	319	312	356	351	349	348	349	349	350	350
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201
Gross Margin	*143*	*144*	*144*	*148*	*147*	*148*	*148*	*148*	*149*	*149*
Other Revenue	2	2	2	2	2	2	2	2	2	2
	145	146	146	149	149	149	150	150	151	151
Expenses										
Operating & Administrative	67	69	77	77	78	78	79	79	81	82
Finance Expense	18	17	21	22	23	25	25	26	27	28
Depreciation & Amortization	28	30	20	21	22	22	23	23	24	25
Capital & Other Taxes	18	19	15	15	16	16	16	17	17	17
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	143	147	144	147	151	153	155	158	161	165
Net Income (loss) before proposed rate increases	$ 2	$ (1)	$ 2	$ 2	$ (2)	$ (3)	$ (5)	$ (7)	$ (10)	$ (13)
Proposed rate increases	-	7	7	7	7	9	11	13	15	18
Net Income (loss) after proposed rate increases	2	6	9	9	5	5	6	6	5	4
Retained Earnings assuming no rate increases *	36	35	(41)	(39)	(43)	(48)	(55)	(66)	(80)	(99)
Retained Earnings including rate increases	36	41	(27)	(18)	(13)	(7)	(2)	4	9	13
Financial Ratios - **with rate increase**										
Equity (PUB Methodology)	34%	33%	27%	22%	22%	23%	23%	23%	23%	23%
Interest Coverage	1.09	1.32	1.43	1.42	1.21	1.21	1.23	1.22	1.17	1.15
Capital Coverage	1.23	0.07	1.02	0.63	0.49	0.63	0.65	0.65	0.62	0.62
Financial Ratios - **without rate increase**										
Equity (PUB Methodology)	34%	32%	25%	18%	17%	15%	14%	11%	9%	6%
Interest Coverage	1.09	0.95	1.07	1.07	0.87	0.81	0.73	0.64	0.53	0.43
Capital Coverage	1.23	(0.10)	0.79	0.42	0.29	0.31	0.23	0.16	0.05	(0.06)

* In a "no rate increase" scenario, finance expense also increases due to additional borrowing requirements. Thus, the difference between *Retained Earnings assuming no rate increase* and *Retained Earnings including rate increases* is not simply the *Proposed rate increases*, but includes additional finance expense.

PUB/CENTRA II-140

Reference: PUB/Centra I-3; 2009/10 & 2010/11 GRA PUB/Centra 2(c) & (d)

a) Please provide the rationale for the reorganization and detail the changes with the ongoing reorganization.

ANSWER:

As noted in PUB/Centra I-3(h), the reorganization was undertaken to support the goals of balancing the executive portfolios as well as realigning activities to deal with the challenges ahead and capitalize on the Corporation's strengths.

The chart that was filed in PUB/Centra I-3(g) reflects the most current organizational structure. The reference in PUB/Centra I-3(b) that implementation of the change associated with this reorganization is ongoing was intended to convey that the necessary administrative steps to implement the reorganization were not yet complete.

PUB/CENTRA II-140

Reference: PUB/Centra I-3; 2009/10 & 2010/11 GRA PUB/Centra 2(c) & (d)

b) Please provide a comparison for the fiscal years 2008/09, 2009/10 and 2010/11 between the total management costs forecast and allocated to Centra at the 2009/10 & 2010/11 GRA with actual allocated management costs reflected in this GRA and explain the variances.

ANSWER:

CENTRA GAS MANITOBA INC.
Corporate Cost of Management in 2012/13 Organization Chart

($000's)

Fiscal Year	Centra Gas Allocation Actual	Centra Gas Allocation Forecast	Variance	Reference
2008/09	967	943	24	1
2009/10	1,080	985	95	2
2010/11	939	1,009	(70)	3

An explanation of the variances is provided below.

1. 2008/09 actual allocations differ from forecasted amounts due to the variability of management staffing levels and salaries.
2. 2009/10 actual allocations are higher than forecast due to the operational responsibilities of two Business Units (Customer Service & Marketing, and Transmission & Distribution) being reorganized into three new Business Units:

Customer Care & Marketing, Customer Service Operations & Distribution, and Transmission. These organizational changes were not included in the forecast.

3. 2010/11 actual allocations are lower than forecast due to a change in the cost allocation methodology. Executive management costs were included in overhead and charged to Centra as a percentage add-on to activity charges. As outlined in Centra's response to PUB-Centra I-3(f), for 2010/11 actual, the allocation driver was changed to the asset base of the utility in order to reflect the Corporation's current operations. This reduction was partially offset by the organizational changes noted above.

PUB/CENTRA II-140

Reference: PUB/Centra I-3; 2009/10 & 2010/11 GRA PUB/Centra 2(c) & (d)

c) Please explain what factors have led to the reduction in forecasted management costs allocated to Centra for 2012/13 and 2013/14.

ANSWER:

As discussed in Centra's response to PUB/Centra I-3(f), the forecasted management costs allocated to Centra for 2012/13 and 2013/14 have decreased due to a change in the cost allocation methodology. Division Manager costs were allocated to the departments they supported up to 2011/12. These costs were included in departmental activity rates and charged either to operating programs, capital projects or included in overhead, dependent on the nature of each department. In order to reflect the Corporation's current operations, these costs were removed from departmental activity rates in 2012/13 and allocated to Centra as follows: for governance areas such as Executive, General Counsel and Corporate Accounting, the driver has been modified to reflect the asset base of the utility, similar to executive management costs. For service and functional areas such as Human Resources, Generation, Distribution and Transmission the costs have been included in overhead and charged to Centra as a percentage add-on to activity charges.

PUB/CENTRA II-141

Reference: PUB/Centra I-6; CAC/Centra I-10(a) – Interest Rate Forecasts

a) Please re-file Table 1 and Table 2 eliminating the forecasts from Bank A and Bank B, and recalculate the forecasted short term and long term interest rates.

ANSWER:

With the 2012 Economic Outlook, the Corporation took the initiative to deepen the information provided by its forecasters by obtaining extended interest rate forecasts from some of the financial institutions where available. Consequently, the Corporation received extended forecast from BMO, Desjardins, Royal Bank of Canada (RBC), and TD Bank. While the extended forecasts from Desjardins and TD Bank were disclosed as part of PUB/Centra I-6, Centra had not yet received permission to disclose the extended forecasts from BMO and RBC. The Corporation has now received permission from BMO and RBC to disclose the near term portion of their extended forecasts (however, the forecast for the periods beyond 2014 remain proprietary). Attached to this response please find the data tables that were provided by these financial institutions up to 2014 Q4.

Table 1 and Table 2 from PUB/Centra I-6 are reproduced on the following pages, and have been amended to show BMO as "Bank 1" and RBC as "Bank 2".[1]

[1] The amended tables also include data that was inadvertently left off of the original table (the 2014 Q1 forecast for CIBC in Tables 1 & 2, and the 2015 Q1 forecast for Conference Board in Table 2). The amended Table 2 also shows the quarterly forecasts for 2014 for Desjardins, which were originally shown as quarterly forecasts from CIBC. None of these amendments changed the fiscal year interest rates as originally calculated in response to PUB/Centra I-6.

Table 1 – Canadian 3 Month T-Bill Rate - %

	Fcst Date	End Period or Average	2012			2013				2014				2015
			Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
BMO	2-Oct-12	Average	**0.98**	**0.98**	**1.00**	**1.00**	**1.00**	**1.00**	**1.25**	**1.25**	**1.50**	**1.50**	**1.75**	*
CIBC	27-Sep-12	End Period	0.98	0.98	0.96	0.95	0.95	0.95	1.08	**1.33**				
Desjardins	1-Sep-12	End Period	0.98	0.98	0.99	1.00	1.00	1.03	1.10	1.55	1.55	1.55	1.55	2.25
Laurentian	17-Sep-12	End Period	0.98	0.98	0.99	1.00	1.00	1.25	1.55					
National Bank	1-Sep-12	End Period	0.98	0.98	0.98	0.96	1.31	1.31	1.31					
RBC	4-Oct-12	End Period	**0.98**	**0.98**	**1.01**	**1.05**	**1.25**	**1.65**	**1.93**					
Scotia Bank	27-Sep-12	End Period	0.98	0.98	0.99	1.00	1.00	1.00	1.00					
TD Bank	18-Sep-12	End Period	0.98	0.98	1.01	1.05	1.23	1.48	1.60	1.68	1.88	2.05	2.08	2.48
Informetrica	1-Oct-12	Average	0.98	0.98	1.20	1.80	1.80	1.80	1.80	2.80	2.80	2.80	2.80	3.90
I H S Global Insight	11-Sep-12	Average	0.98	0.98	1.03	1.03	1.06	1.13	1.42	1.63	1.93	2.17	2.39	2.73
Conference Board	19-Sep-12	Average	0.98	0.98	1.03	0.99	0.97	1.03	1.18	1.37	1.48	1.64	1.83	2.08

			2012/13	2013/14	2014/15
EO2012- Fiscal			1.00	1.30	2.10

NOTE 1: 2012 Q2 and Q3 are actual data.
NOTE 2: The forecast for 2015 Q1 provided by BMO is proprietary and cannot be disclosed.

Table 2 – Canadian 10 Year+ Bond Yield Rate - %

	Fcst Date	End Period or Average	2012 Q2	2012 Q3	2012 Q4	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2015 Q1
BMO	2-Oct-12	Average	**2.25**	**2.10**	**2.03**	**1.98**	**2.05**	**2.20**	**2.38**	**2.60**	**2.85**	**3.13**	**3.38**	*
CIBC	27-Sep-12	End Period	2.25	2.10	2.07	2.24	2.51	2.71	2.81	**2.86**				
Desjardins	1-Sep-12	End Period	2.25	2.10	2.12	2.20	2.23	2.36	2.50	**2.75**	**2.75**	**2.75**	**2.75**	**3.48**
Laurentian	17-Sep-12	End Period	2.25	2.10	2.07	2.15	2.25	2.59	2.98					
National Bank	1-Sep-12	End Period	2.25	2.10	2.04	1.98	2.28	2.28	2.28					
RBC	4-Oct-12	End Period	**2.25**	**2.10**	**2.08**	**2.23**	**2.40**	**2.58**	**2.75**	**3.00**	**3.38**	**3.75**	**4.10**	*
Scotia Bank	27-Sep-12	End Period	2.25	2.10	2.02	2.05	2.19	2.34	2.59					
TD Bank	18-Sep-12	End Period	2.25	2.10	2.18	2.35	2.43	2.53	2.69	2.86	2.99	3.11	3.23	
Informetrica	1-Oct-12	Average	2.25	2.10	2.20	2.80	2.80	2.80	2.80	3.60	3.60	3.60	3.60	4.30
I H S Global Insight	11-Sep-12	Average	2.25	2.10	2.04	2.11	2.27	2.76	3.07	3.10	3.17	3.21	3.34	3.54
Conference Board	19-Sep-12	Average	2.25	2.10	2.08	2.03	1.98	1.98	2.01	2.08	2.12	2.19	2.29	**2.41**
			2012/13		**2013/14**		**2014/15**							
EO2012- Fiscal			2.15		2.55		3.20							

NOTE 1: 2012 Q2 and Q3 are actual data.
NOTE 2: The extended forecasts for 2015 Q1 provided by BMO and RBC are proprietary and cannot be disclosed.

Tables 1 and 2 have been reproduced as Tables 3 and 4 to exclude the forecasts provided by BMO (Bank A from PUB/Centra I-6) and RBC (Bank B from PUB/Centra I-6) and are shown on the following pages. Note that the elimination of these two forecasters did not impact the calculation of the forecasted short term and long term interest rates for the 2012/13 Forecast and 2013/14 Test Year.

Table 3 - Canadian 3 Month T-Bill Rate - % - excluding BMO & RBC

			2012			2013				2014				2015
	Fcst Date	End of Period or Average	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
CIBC	27-Sep-12	End period	0.98	0.98	0.96	0.95	0.95	0.95	1.08	1.33				
Desjardins	1-Sep-12	End period	0.98	0.98	0.99	1.00	1.00	1.03	1.10	1.55	1.55	1.55	1.55	2.25
Laurentian	17-Sep-12	End period	0.98	0.98	0.99	1.00	1.00	1.25	1.55					
National Bank	1-Sep-12	End period	0.98	0.98	0.98	0.96	1.31	1.31	1.31					
Scotiabank	27-Sep-12	End period	0.98	0.98	0.99	1.00	1.00	1.00	1.00					
TD Bank	18-Sep-12	End period	0.98	0.98	1.01	1.05	1.23	1.48	1.60	1.68	1.88	2.05	2.08	2.48
Informetrica	1-Oct-12	Average	0.98	0.98	1.20	1.80	1.80	1.80	1.80	2.80	2.80	2.80	2.80	3.90
IHS Global Insight	11-Sep-12	Average	0.98	0.98	1.03	1.03	1.06	1.13	1.42	1.63	1.93	2.17	2.39	2.73
Conference Board	19-Sep-12	Average	0.98	0.98	1.03	0.99	0.97	1.03	1.18	1.37	1.48	1.64	1.83	2.08

	2012/13	2013/14	2014/15
EO2012 - Fiscal	1.00	1.30	2.20
EO2012 - Fiscal (all sources)	1.00	1.30	2.10

Table 4 - Canadian 10 Year+ Bond Yield Rate - % - excluding BMO & RBC

			2012			2013				2014				2015
	Fcst Date	End of Period or Average	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
CIBC	27-Sep-12	End period	2.25	2.10	2.07	2.24	2.51	2.71	2.81	2.86				
Desjardins	1-Sep-12	End period	2.25	2.10	2.12	2.20	2.23	2.36	2.50	2.75	2.75	2.75	2.75	3.48
Laurentian	17-Sep-12	End period	2.25	2.10	2.07	2.15	2.25	2.59	2.98					
National Bank	1-Sep-12	End period	2.25	2.10	2.04	1.98	2.28	2.28	2.28					
Scotiabank	27-Sep-12	End period	2.25	2.10	2.02	2.05	2.19	2.34	2.59					
TD Bank	18-Sep-12	End period	2.25	2.10	2.18	2.35	2.43	2.53	2.69	2.86	2.99	3.11	3.23	
Informetrica	1-Oct-12	Average	2.25	2.10	2.20	2.80	2.80	2.80	2.80	3.60	3.60	3.60	3.60	4.30
IHS Global Insight	11-Sep-12	Average	2.25	2.10	2.04	2.11	2.27	2.76	3.07	3.10	3.17	3.21	3.34	3.54
Conference Board	19-Sep-12	Average	2.25	2.10	2.08	2.03	1.98	1.98	2.01	2.08	2.12	2.19	2.29	2.41

	2012/13	2013/14	2014/15
EO2012 - Fiscal	2.15	2.55	3.10
EO2012 - Fiscal (all sources)	2.15	2.55	3.20

Quarterly Medium Term Outlook

RBC *

			2012				2013				2014			
			Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Cdn Overnight Rate	quarterly end-of-period - %	**Oct 4-12**	1.00	1.00	1.00	1.00	1.00	1.25	1.75	2.00	2.25	2.75	3.00	3.25
Cdn 90 Day T-bill	quarterly end-of-period - %	**Oct 4-12**	0.92	0.88	0.90	1.05	1.05	1.45	1.85	2.00				
Cdn 10 Yr Bond Yield	quarterly end-of-period - %	**Oct 4-12**	2.12	2.20	2.30	1.85	2.05	2.20	2.40	2.55	2.90	3.30	3.65	4.00
Cdn 30 Yr Bond Yield	quarterly end-of-period - %	**Oct 4-12**	2.67	2.70	2.80	2.40	2.60	2.75	2.95	3.10	3.45	3.85	4.20	4.55
US Fed Funds	quarterly end-of-period - %	**Oct 4-12**	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
US 90 day T-bill	quarterly end-of-period - %	**Oct 4-12**	0.07	0.05	0.05	0.05	0.05	0.05	0.05	0.05				
US 10 Yr Bond Yield	quarterly end-of-period - %	**Oct 4-12**	2.23	1.95	2.05	1.75	1.95	2.10	2.30	2.45	2.55	2.70	2.80	2.90
US 30 Yr Bond Yield	quarterly end-of-period - %	**Oct 4-12**	3.35	3.20	3.40	3.00	3.25	3.50	3.70	3.95	4.00	4.05	4.10	4.15
Exchange Rate	(C$/US$)	**Oct 4-12**	1.00	1.02	1.01	0.99	0.97	0.94	0.95	0.96	0.98	1.00	1.02	1.04
Cdn Core CPI (y/y %)	Y/Y - % change	**Oct 4-12**	2.1	2.0	1.6	1.7	1.9	1.8	2.0	1.9	1.9	2.1	2.0	2.0
Cdn Headline CPI (y/y %)	Y/Y - % change	**Oct 4-12**	2.3	1.6	1.3	1.3	1.2	1.5	1.9	1.9				
Cdn GDP Price Deflator	Q/Q - % change; annualized rate	**Oct 4-12**	1.9	0.7	0.9	0.2	1.0	1.5	1.7	2.0				
US Core CPI (y/y %)	Y/Y - % change	**Oct 4-12**	2.2	2.3	2.0	2.0	1.9	1.8	1.8	1.7	1.9	1.9	1.9	1.6
US Headline CPI (y/y %)	Y/Y - % change	**Oct 4-12**	2.8	1.9	1.7	1.7	1.4	1.7	1.7	1.8				
US GDP Price Deflator	Q/Q - % change; annualized rate	**Oct 4-12**	2.0	1.7	1.4	1.7	1.5	1.5	1.5	1.5				

* Financial data are quarterly end-of-period forecasts. Economic data are quarterly average forecasts.
**If data can only be provided in annual granularity, assume it is the same for each quarter.

Quarterly Medium Term Outlook

BMO Capital Markets *

	Forecast Date	2012				2013				2014			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Cdn 90 Day T-bill - %	**2-Oct-12**				1.00	1.00	1.00	1.00	1.25	1.25	1.50	1.50	1.75
Cdn 10 Yr Bond Yield - %	**2-Oct-12**				1.75	1.70	1.80	1.95	2.10	2.35	2.60	2.90	3.15
Cdn 30 Yr Bond Yield - %	**2-Oct-12**				2.30	2.25	2.30	2.45	2.65	2.85	3.10	3.35	3.60
US 90 day T-bill - %	**2-Oct-12**				0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
US 10 Yr Bond Yield - %	**2-Oct-12**				1.65	1.60	1.70	1.80	1.95	2.15	2.40	2.65	2.90
US 30 Yr Bond Yield - %	**2-Oct-12**				2.85	2.75	2.80	2.90	3.00	3.20	3.40	3.60	3.80
Exchange Rate**	**2-Oct-12**				0.97	0.99	1.00	0.99	0.98	0.98	0.97	0.97	0.96
Cdn CPI*** - % change	**2-Oct-12**			1.40	1.30	1.40	1.80	2.20	1.90	2.00			
Cdn GDP Price Index - % change	**2-Oct-12**			3.20	2.30	2.00	2.00	1.80	1.90	2.00			
US CPI*** - % change	**2-Oct-12**			1.70	2.30	2.30	2.70	2.60	2.10	2.00			
US GDP Price Index - % change	**2-Oct-12**			1.60	2.90	2.20	2.20	1.70	1.60	2.00			

* Average Period Data
** (C$/US$)
*** CPI All Items (year/year % change)
**** shaded area denotes forecast period

PUB/CENTRA II-141

Reference: PUB/Centra I-6; CAC/Centra I-10(a) – Interest Rate Forecasts

b) Please provide the detailed narratives describing all of the updates and adjustments made to the interest rate forecasts in order to arrive at Centra's forecast for short term and long term interest rates, including the process for correcting end of period to average period data.

ANSWER:

Overview

The development of the Economic Outlook is a corporate activity with the information being used for a variety of corporate processes.[1] The information gathered in the Economic Outlook spans a broad array of key economic indicators, including the forecasting of short and long term interest rates.[2] The analysis reported in the Economic Outlook is based on a consensus view of several independent sources including Canada's primary financial institutions and several other independent sources, all of which are well known and respected. In addition to providing a consensus average for Centra's IFF base case, the Corporation's forecasting methodology also assists Centra with its risk mitigation efforts as it identifies the range between the highest and lowest projections within the utilized forecasts, as well as the distribution within the range.

[1] As stated in the preface of the Economic Outlook provided in Appendix 4.1, "This information is used in several areas of the corporation; for example, in load forecasting, project evaluation, and financial planning." The Economic Outlook also has a number of end users, including Centra.

[2] The report also provides tables, graphs, and written summaries for the following key economic indicators: Real Gross Domestic Product; Consumer Price Index; GDP Price Deflator; Population including Manitoba Aboriginal Population; Employment; Housing; and the C$/US$ exchange rate.

Forecast Reviews

The Economic Outlook is prepared in the spring of each year, which is the start of the Corporation's annual forecasting cycle, and is based on what was known and could reasonably be foreseen at the time of its preparation. Due to continued uncertainty and volatility of the current economic environment, the forecasts of key variables such as interest rates are reviewed in the summer and fall. As IFF12 was produced in late fall/ early winter, the fall interest rate forecast was utilized. In the event of significant changes in the macro-economy (such as those that occurred in the midst of the financial crisis), an IFF update may be published in advance of the next scheduled IFF. In these unusual circumstances, care must be exercised in order to avoid creating a forecast distortion by only adjusting one macro-economic variable (such as interest rates) without adjusting the IFF for the entire complex array of potentially dependent variables.

The Corporation monitors changing conditions throughout the year and provides variance explanations as part of its financial reporting. As the Corporation's rates are set under a cost of service methodology, with retained earnings held for the benefit of ratepayers along with the self-correcting ability to adjust the revenue requirement at the next GRA, consistent with Orders 128/09 and 5/12 there is no need to establish deferral accounts to accumulate interest rate/cost variances.[3]

[3] As per Order 128/09 dated September 16, 2009:

> "The Board does not agree with CAC/MSOS on the need for a deferral account for Finance Expense. The Board believes that the update provided for in this Order and the methodology changes proposed for future applications should adequately ensure that an appropriate interest rate is determined for rate setting purposes" (page 63).

As per Order 5/12 dated January 17, 2012 in response to a CAC/MSOS recommendation for an interest rate deferral account that would "capture the difference between forecast and actual finance costs, addressing forecast differences in interest costs" (page 87), the PUB stated that:

> "The Board believes that the adoption of an interest rate deferral account is not appropriate at this time" (page 89).

The Forecasters

For the purpose of the 2012 Economic Outlook, the forecasting sources include IHS Global Insight, the Conference Board of Canada, Informetrica, Spatial Economics, BMO Nesbitt Burns, CIBC, Desjardins, Laurentian, Royal Bank of Canada, Scotiabank, National Bank of Canada, and TD Bank.[4] All of the forecasters utilize professionally trained and experienced economists who have their own proprietary processes and perspectives. These differing processes and perspectives will lead in most circumstances to differing recommendations and professional judgments.

It was previously recommended that Centra develop a "process to retrospectively test the accuracy of forecasters to assess their inclusion in future forecasts."[5] During the 2010/11 & 2011/12 Electric GRA, the rationale for the retrospective testing of interest rate forecasters was again extensively canvassed.[6] As part of Centra's 2011/12 Cost of Gas Application, on April 1, 2011 Centra described its position regarding the retrospective testing of interest rate forecasters in response to PUB/Centra 50 (b). In this response Centra cited a Bank of Canada working paper entitled "*Combining Canadian Interest-Rate Forecasts*" which

[4] The listing of these forecasters was provided in Appendix 4.1 on page 5 of the 2012 Economic Outlook (Spring). The Corporation does not have a view regarding the optimal number of sources within its pool of independent forecasters. The number of source forecasters was increased in the 2012 Economic Outlook with the addition of Desjardins and Laurentian (both are established Canadian financial institutions that provide near term macro-economic updates). Other forecasters considered at this time, but not added to the pool, included UBS Warburg, J.P. Morgan, Merrill Lynch, Deutsche Bank and Economap Strategic Economic Advisors. As the forecast for Spatial Economics is only produced in the spring, it was not utilized for the fall review due to the staledatedness of the information. No forecasters have been removed from the pool since the 2010 Economic Outlook (when Consensus Economics, Federal Finance and the Province of British Columbia were removed as their forecasts were not considered to be statistically independent).

[5] PUB Order 128/09 Directive No. 9, dated September 16, 2009, page 137.

[6] For further background and chronology pertaining to the topic of the Corporation's interest rate forecasting methodology and the retrospective testing of interest rate forecasters, see Centra's response to PUB/Centra I–10 from the 2013/14 Centra GRA.

reviewed more than 30 years of monthly Canadian interest rates.[7] Centra concluded that:

> "It is Centra's view that the collective economic opinion that currently exists within Centra's established portfolio of respected forecasters provides a valuable strength of diversity, and that a process to retrospectively test the accuracy of forecasters to assess their inclusion in future forecasts is not beneficial at this time."[8]

Since April 2011, the Corporation has broadened this strength of diversity by adding Desjardins and Laurentian to its pool of forecasters. Regarding retrospective testing of interest rate forecasters, it remains the Corporation's view that:

a) forecaster modeling algorithms are evolving since the financial crisis and that sufficient time through a full business cycle has not transpired to appropriately test the accuracy of these algorithms;

b) the established forecasting methodology, along with cost of service regulation mitigates the need for retrospective testing for rate setting purposes;

c) it is important for the Corporation to consider the broad range of respected forecaster opinion; and

d) retrospective testing, with the aim of pruning or weighting forecaster opinions could potentially weaken or bias the Corporation's viewpoints in terms of understanding the spectrum of possibilities and mitigating the risk.

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7 *"Combining Canadian Interest-Rate Forecasts"* by David Jamieson Bolder and Yuliya Romanyuk; Bank of Canada Working Paper 2008-34; September 2008. This working paper is available online at http://www.bankofcanada.ca/wp-content/uploads/2010/02/wp08-34.pdf. Manitoba Hydro/ Centra also conducted a telephone conference call with one of the authors of the working paper in spring 2011 in order: a) to review the research paper findings; b) to discuss the Corporation's view on the retrospective testing of its forecasters, and; c) to seek enhancements to the Corporation's interest rate forecasting methodology.

8 As excerpted from Centra's response to PUB/Centra 50 (b) from the 2011/12 Cost of Gas Application. On April 28, 2011 in PUB Order 65/11 the PUB did not recommend or redirect Centra to undertake retrospective testing of its interest rate forecasters.

Forecast Adjustments

Since the receipt of Order 128/09, the Corporation undertakes adjustments to third party forecast data, where necessary. For example, end of period source forecasts are converted to average period data by taking the simple average between the two end points.[9]

The interest rate forecasters are typically in one of two categories:

a) financial institutions (such as BMO, CIBC, and Royal Bank of Canada) that provide near term, publicly available forecasts;[10] or

b) macro-economic forecasters (such as Informetrica, IHS Global Insight, Conference Board and Spatial Economics) that provide forecasts spanning from the near term through to longer terms.

In the near term, the preponderance of forecasters provide data with quarterly (3 month) granularity while the long term forecasts may only provide annual (12 month) data. Although the granularity between quarterly and annual data sets are not the same, it is the Corporation's position that the combined interest rate forecast is made stronger with their

9 Converting end of period forecasts to average forecasts is considered by the Corporation to be a computational adjustment and not a correction. The underlying assumption with these revisions is that a simple averaging of two end points is reasonable (it is conceivable that the weighted average through the time period may not equal the simple average). Therefore, given the circumstance where the external forecaster provided end of period information and did not specifically provide their average over the period, it is technically imprecise to indicate that the average calculated by the Corporation with this process represents the view of the external forecaster. As a practical matter, the Corporation considers the impact of these computational adjustments, and potential variations between simple and weighted averages, to be normally immaterial in the overall financial forecast.

10 With the 2012 Economic Outlook, the Corporation took the initiative to deepen the information provided by these forecasters by obtaining extended interest rate forecasts from some of the financial institutions where available. Consequently, the Corporation received extended forecasts from BMO, Desjardins, Royal Bank of Canada, and TD Bank. As described in response to PUB/Centra II–141 (a), the Corporation has received permission from BMO and the Royal Bank of Canada to disclose the near term portion of their extended forecasts. However, the forecast for the periods beyond 2014 remain proprietary.

integration.[11] Annual calendar year information is adjusted to fiscal year information on a proportionate basis. The data for the fiscal year is then combined and averaged to derive the base interest rate forecast for the period.[12]

As described in response to PUB/Centra I–6, the Corporation's short term interest rate is the sum of the combined source forecasts for the Canadian 3 month T-Bill rate plus the 1% provincial debt guarantee fee.

The Corporation's Canadian long term interest rate is calculated by adding the appropriate credit spread to the Canadian 10 Year+ bond yield rate and the 1% provincial debt guarantee fee.[13]

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[11] This follows the view described in the Bank of Canada's working paper entitled "*Combining Canadian Interest-Rate Forecasts*" wherein on page 2 of the paper the authors state that:

> "The concept of model averaging has a relatively long history in the forecasting literature. Indeed, there is evidence dating back to Bates and Granger (1969) and Newbold and Granger (1974) suggesting that combination forecasts often outperform individual forecasts. … even if misspecified models are combined, the combination may, and often will, improve the forecasts."

[12] Rounded to the nearest 5 basis points.

[13] For the Canadian long term interest rate forecast, the average of the 10 year and 30 year Canadian long bond data points are used as inputs into the Corporation's long-term interest rate forecast. The methodology for the credit spread between the benchmark Government of Canada bonds and the all-in cost to the Province of Manitoba, as well as the need to need to simultaneously consider both the benchmark rates and the credit spreads, was extensively canvassed at the 2010/11 & 2011/12 Electric GRA. For a general description of the Canadian 10 Year+ credit spread process, please see the Corporation's response to CAC/MSOS/MH I–135 (i) from the aforementioned proceeding.

PUB/CENTRA II-141

Reference: PUB/Centra I-6; CAC/Centra I-10(a) – Interest Rate Forecasts

c) Please demonstrate Centra's compliance to Order 128/09 Directive 9, as it does not appear that Centra (as opposed to Manitoba Hydro) has done so in any filing to the PUB.

ANSWER:

Manitoba Hydro's treasury function is managed on a consolidated basis; the Corporation does not maintain a separate interest rate forecast for Centra. Although Directive 9 of Order 128/09 was issued to Centra, amendments have been made to the interest rate forecasting methodology used for the consolidated operations of Manitoba Hydro.

On December 10, 2010, Centra reported to the PUB on the status of directives, including Directive 9 from Order 128/09 (see Attachment 1 to the response to CAC/Centra I-10 (a)). Centra reported the status of Directive 9 as "Complete", as the matter of the Corporation's revised interest rate forecasting methodology was extensively canvassed at Manitoba Hydro's 2010/11 & 2011/12 General Rate Application.

In addition, as part of Centra's 2011/12 Cost of Gas Application, on April 1, 2011 Centra described its position regarding the retrospective testing of interest rate forecasters in response to PUB/Centra 50(b).

PUB/CENTRA II-141

Reference: PUB/Centra I-6; CAC/Centra I-10(a) – Interest Rate Forecasts

d) Please re-file Table 1 and Table 2 with the most recently updated interest rate forecasts, as well as eliminating the forecasts from Bank A and Bank B, and recalculate the forecasted short term and long term interest rates.

ANSWER:

Centra will re-file Table 1 and Table 2 when the 2013 Spring Economic Outlook is finalized.

PUB/CENTRA II-141

Reference: PUB/Centra I-6; CAC/Centra I-10(a) – Interest Rate Forecasts

e) Please explain why Centra has included the 90 day commercial paper forecast from Informetrica in its table of Canadian 3-month T-bill forecasts.

ANSWER:

For the purposes of the interest rate forecast, 90 day commercial paper and Canadian 3 month T-Bills are considered synonymous.

PUB/CENTRA II-141

Reference: PUB/Centra I-6; CAC/Centra I-10(a) – Interest Rate Forecasts

f) Please explain why it is appropriate to use the Informetrica forecasts considering they provide only a single data point for each calendar year.

ANSWER:

In the near term, the preponderance of forecasters provide data with quarterly (3 month) granularity while the long term forecasts such as Informetrica may only provide annual (12 month) data. Although the granularity between quarterly and annual data sets are not the same, it is the Corporation's position that the combined interest rate forecast is made stronger with their integration.

For further information regarding the forecast adjustments within the Corporation's interest rate forecasting methodology, please see the response to PUB/Centra II-141(b).

PUB/CENTRA II-141

Reference: PUB/Centra I-6; CAC/Centra I-10(a) – Interest Rate Forecasts

g) Please re-file Table 1 and Table 2 with the most recently updated interest rate forecasts, as well as eliminating the forecasts from Banks A and B and Infometrica, and recalculate the forecasted short term and long term interest rates.

ANSWER:

Centra will re-file Table 1 and Table 2 when the 2013 Spring Economic Outlook is finalized.

PUB/CENTRA II-142

Reference: PUB/Centra I-7(c); PUB/Centra 2(a)

Please re-file the response including the financial targets for gas operations only in a similar level of detail as that provided in response to PUB/Centra I‐2(a)

ANSWER:

Please see the table below.

Grandfathering Rate Regulated Accounting & IFRS Deferred until 2015/16

(in millions of $)	Forecast 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
General Consumers Revenue										
- at approved rates	$ 322	$ 316	$ 360	$ 351	$ 349	$ 348	$ 349	$ 349	$ 350	$ 350
Furnace Replacement Program	(4)	(4)	(4)	-	-	-	-	-	-	-
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201
Gross Margin	*143*	*144*	*144*	*148*	*147*	*148*	*148*	*148*	*149*	*149*
Other Revenue	2	2	2	2	2	2	2	2	2	2
	145	146	146	149	149	149	150	150	151	151
Expenses										
Operating & Administrative	67	69	71	70	71	73	74	76	77	79
Finance Expense	18	17	19	20	22	23	24	25	26	27
Depreciation & Amortization	28	30	31	30	31	32	32	33	32	33
Capital & Other Taxes	18	19	19	19	19	20	20	20	20	20
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	143	147	152	151	155	159	162	165	167	171
Net Income (loss) before proposed rate increases	$ 2	$ (1)	$ (6)	$ (1)	$ (6)	$ (10)	$ (12)	$ (15)	$ (16)	$ (19)
Proposed rate increases	-	7	7	7	7	9	11	13	15	18
Net Income (loss) after proposed rate increases	2	6	1	6	1	(1)	(1)	(2)	(1)	(2)
Retained Earnings before proposed rate increases	36	35	29	27	20	9	(5)	(24)	(44)	(69)
Retained Earnings after proposed rate increases	36	42	43	49	50	49	48	46	45	43
Financial Ratios - **with rate increase**										
Equity (PUB Methodology)	34%	33%	32%	32%	32%	31%	30%	29%	28%	28%
Interest Coverage	1.09	1.32	1.06	1.28	1.06	0.95	0.97	0.92	0.94	0.93
Capital Coverage	1.23	0.07	1.03	0.69	0.58	0.69	0.71	0.69	0.68	0.66
Financial Ratios - **without rate increase**										
Equity (PUB Methodology)	34%	32%	30%	29%	27%	25%	22%	19%	15%	11%
Interest Coverage	1.09	0.95	0.67	0.90	0.70	0.54	0.46	0.35	0.31	0.22
Capital Coverage	1.23	(0.10)	0.84	0.52	0.40	0.41	0.33	0.24	0.15	0.03

PUB/CENTRA II-143

Reference: PUB/Centra I-10

a) Please indicate the level of rate increases required to eliminate the forecast deficit in retained earnings by 2016/17 within a two year period, assuming the continuation of the FRP funding to 2016/17.

ANSWER:

Please see the following tables:

GAS OPERATIONS (CGM12)
PROJECTED OPERATING STATEMENT
FRP Funding Extended 2 years, 0 Retained Earnings by 2017
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES										
General Consumers										
at approved rates	319	312	356	347	345	348	349	349	350	350
additional revenue requirement*	0	7	10	14	17	19	22	23	25	28
	319	319	366	360	362	367	370	373	375	378
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201
Gross Margin	143	151	154	157	160	166	169	172	174	177
Other	2	2	2	2	2	2	2	2	2	2
	145	153	156	159	162	168	171	174	176	179
EXPENSES										
Operating and Administrative	67	69	77	77	78	78	79	79	81	82
Finance Expense	18	17	21	22	23	24	24	24	24	24
Depreciation and Amortization	28	30	20	21	22	22	23	23	24	25
Capital and Other Taxes	18	19	15	15	16	16	16	17	17	17
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	143	147	144	147	151	152	153	155	158	161
Net Income	2	6	12	12	12	16	18	19	18	19

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
* Additional Revenue Requirement										
Percent Increase		2.00%	0.95%	0.95%	0.95%	0.50%	0.75%	0.50%	0.50%	0.75%
Cumulative Percent Increase		2.00%	2.97%	3.95%	4.94%	5.46%	6.25%	6.78%	7.32%	8.12%

GAS OPERATIONS (CGM12)
PROJECTED BALANCE SHEET
FRP Funding Extended 2 years, 0 Retained Earnings by 2017
(In Millions of Dollars)

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
ASSETS									
Plant in Service	656	679	705	735	767	788	811	835	860
Accumulated Depreciation	(232)	(240)	(245)	(252)	(260)	(269)	(278)	(288)	(299)
Net Plant in Service	424	439	460	483	507	520	533	546	561
Construction in Progress	2	2	2	2	2	4	6	8	8
Current and Other Assets	73	68	68	68	68	68	68	68	69
Goodwill and Intangible Assets	9	8	6	5	4	3	3	3	3
Regulated Assets	79	78	-	-	-	-	-	-	-
	586	594	536	557	580	595	610	625	641
LIABILITIES AND EQUITY									
Long-Term Debt	295	290	330	330	340	350	350	350	350
Current and Other Liabilities	99	96	64	73	75	63	61	58	56
Contributions in Aid of Construction	35	45	45	45	44	45	44	43	42
Share Capital	121	121	121	121	121	121	121	121	121
Retained Earnings	36	41	(24)	(12)	-	16	34	53	71
	586	594	536	557	580	595	610	625	641

GAS OPERATIONS (CGM12)
PROJECTED CASH FLOW STATEMENT
FRP Funding Extended 2 years, 0 Retained Earnings by 2017
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES										
Cash Receipts from Customers	355	357	405	399	401	402	405	408	411	414
Cash Paid to Suppliers and Employees	(291)	(335)	(348)	(347)	(348)	(348)	(349)	(350)	(353)	(355)
Interest Paid	(19)	(19)	(20)	(21)	(22)	(22)	(23)	(23)	(23)	(23)
	45	3	37	30	30	32	34	35	35	36
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	60	30	40	-	10	10	-	-	-	-
Retirement of Long-Term Debt	(63)	-	(35)	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	(3)	30	5	-	10	10	-	-	-	-
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(37)	(39)	(33)	(37)	(40)	(32)	(33)	(33)	(34)	(34)
Other	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	(37)	(39)	(33)	(38)	(41)	(34)	(34)	(34)	(34)	(35)
Net Increase (Decrease) in Cash	5	(7)	8	(8)	(0)	8	(0)	1	1	1
Cash at Beginning of Year	(13)	(9)	(15)	(7)	(15)	(15)	(7)	(7)	(6)	(5)
Cash at End of Year	(9)	(15)	(7)	(15)	(15)	(7)	(7)	(6)	(5)	(4)

<u>PUB/CENTRA II-143</u>

Reference: PUB/Centra I-10

b) Please provide an updated CGM12 assuming the discontinuance of the FRP funding beyond 2012/13, (the accumulated balance retained to fund the FRP in the future) with the requested rate increase adjusted to maintain the proposed level of Net Income in the Test Year. Provide any other assumptions on future rate increases to maintain a minimum of 25% equity (PUB-method) in each of the years.

<u>ANSWER</u>:

Please see the following tables:

GAS OPERATIONS (CGM12)
PROJECTED OPERATING STATEMENT
FRP Funding Discontinued in '14, Maintain Net Income in '14, Minimum 25% PUB Equity '15 Onward
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES										
General Consumers										
at approved rates	319	316	360	351	349	348	349	349	350	350
additional revenue requirement*	0	3	10	19	19	19	19	19	19	20
	319	319	370	369	368	368	368	369	369	370
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201
Gross Margin	143	151	158	166	167	167	167	168	168	169
Other	2	2	2	2	2	2	2	2	2	2
	145	153	160	168	169	169	169	170	170	171
EXPENSES										
Operating and Administrative	67	69	77	77	78	78	79	79	81	82
Finance Expense	18	17	21	22	22	23	23	23	23	23
Depreciation and Amortization	28	30	20	21	22	22	23	23	24	25
Capital and Other Taxes	18	19	15	15	16	16	16	17	17	17
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	143	147	144	147	150	151	152	154	157	160
Net Income	2	6	16	22	19	18	17	16	13	11
* Additional Revenue Requirement										
Percent Increase		1.00%	2.00%	2.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Cumulative Percent Increase		1.00%	3.02%	5.60%	5.60%	5.60%	5.60%	5.60%	5.60%	5.60%
Financial Ratios										
Equity Ratio (PUB Approved Methodology)	34%	33%	28%	25%	28%	30%	32%	34%	36%	37%
Interest Coverage	1.09	1.35	1.75	1.99	1.84	1.79	1.74	1.68	1.56	1.46
Capital Coverage	1.23	(0.01)	1.11	0.95	0.82	1.02	0.97	0.93	0.88	0.86

GAS OPERATIONS (CGM12)
PROJECTED BALANCE SHEET
FRP Funding Discontinued in '14, Maintain Net Income in '14, Minimum 25% PUB Equity '15 Onward
(In Millions of Dollars)

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
ASSETS										
Plant in Service	656	679	705	735	767	788	811	835	860	886
Accumulated Depreciation	(232)	(240)	(245)	(252)	(260)	(269)	(278)	(288)	(299)	(310)
Net Plant in Service	424	439	460	483	507	520	533	546	561	576
Construction in Progress	2	2	2	2	2	4	6	8	8	8
Current and Other Assets	73	68	68	68	68	68	68	68	68	68
Goodwill and Intangible Assets	9	8	6	5	4	3	3	3	3	3
Regulated Assets	79	78	-	-	-	-	-	-	-	-
	586	594	536	557	580	595	610	625	640	655
LIABILITIES AND EQUITY										
Long-Term Debt	295	300	330	330	340	340	340	350	350	340
Current and Other Liabilities	99	86	60	59	55	50	50	40	43	58
Contributions in Aid of Construction	35	45	45	45	44	45	44	43	42	41
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	36	42	(20)	2	21	39	55	71	84	95
	586	594	536	557	580	595	610	625	640	655

GAS OPERATIONS (CGM12)
PROJECTED CASH FLOW STATEMENT
FRP Funding Discontinued in '14, Maintain Net Income in '14, Minimum 25% PUB Equity '15 Onward
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES										
Cash Receipts from Customers	355	353	404	405	404	403	403	404	404	405
Cash Paid to Suppliers and Employees	(291)	(335)	(348)	(348)	(349)	(348)	(349)	(350)	(352)	(352)
Interest Paid	(19)	(19)	(21)	(21)	(22)	(22)	(22)	(23)	(23)	(23)
	45	(1)	36	35	33	33	32	31	30	30
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	60	40	30	-	10	-	-	10	-	10
Retirement of Long-Term Debt	(63)	-	(35)	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	(3)	40	(5)	-	10	-	-	10	-	10
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(37)	(39)	(33)	(37)	(40)	(32)	(33)	(33)	(34)	(34)
Other	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	(37)	(39)	(33)	(38)	(41)	(34)	(34)	(34)	(34)	(35)
Net Increase (Decrease) in Cash	5	(0)	(2)	(2)	2	(1)	(2)	7	(5)	5
Cash at Beginning of Year	(13)	(9)	(9)	(11)	(13)	(11)	(12)	(14)	(7)	(12)
Cash at End of Year	(9)	(9)	(11)	(13)	(11)	(12)	(14)	(7)	(12)	(7)

PUB/CENTRA II-143

Reference: PUB/Centra I-10

c) Please provide an updated CGM12 with required rate increases to maintain a capital coverage ratio of greater than 1.0 in each year of the forecast.

ANSWER:

Please see the following tables:

GAS OPERATIONS (CGM12)
PROJECTED OPERATING STATEMENT
Capital Coverage Ratio Greater than 1.0 for 2015 and beyond
(In Millions of Dollars)

For the year ended March 31

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES										
General Consumers										
at approved rates	319	312	356	351	349	348	349	349	350	350
additional revenue requirement*	0	7	7	21	26	27	27	27	27	27
	319	319	363	371	375	375	375	376	376	377
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201
Gross Margin	143	151	151	168	174	174	174	175	175	176
Other	2	2	2	2	2	2	2	2	2	2
	145	153	153	170	176	176	176	177	177	178
EXPENSES										
Operating and Administrative	67	69	77	77	78	78	79	79	81	82
Finance Expense	18	17	21	22	22	22	22	22	22	22
Depreciation and Amortization	28	30	20	21	22	22	23	23	24	25
Capital and Other Taxes	18	19	15	15	16	16	16	17	17	17
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	143	147	144	147	150	151	152	153	156	158
Net Income	2	6	9	23	25	25	25	24	22	20
* Additional Revenue Requirement										
Percent Increase		2.00%	0.00%	4.11%	1.39%	0.00%	0.00%	0.00%	0.00%	0.00%
Cumulative Percent Increase		2.00%	2.00%	6.19%	7.67%	7.67%	7.67%	7.67%	7.67%	7.67%
Financial Ratios										
Equity Ratio (PUB Approved Methodology)	34%	33%	27%	24%	28%	31%	35%	39%	41%	44%
Interest Coverage	1.09	1.32	1.43	2.04	2.13	2.13	2.11	2.07	1.99	1.90
Capital Coverage	1.23	0.07	1.02	1.00	1.00	1.26	1.23	1.19	1.13	1.07

GAS OPERATIONS (CGM12)
PROJECTED BALANCE SHEET
Capital Coverage Ratio Greater than 1.0 for 2015 and beyond
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS										
Plant in Service	656	679	705	735	767	788	811	835	860	886
Accumulated Depreciation	(232)	(240)	(245)	(252)	(260)	(269)	(278)	(288)	(299)	(310)
Net Plant in Service	424	439	460	483	507	520	533	546	561	576
Construction in Progress	2	2	2	2	2	4	6	8	8	8
Current and Other Assets	73	68	68	68	68	70	76	81	85	86
Goodwill and Intangible Assets	9	8	6	5	4	3	3	3	3	3
Regulated Assets	79	78	-	-	-	-	-	-	-	-
	586	594	536	557	580	597	618	639	657	674
LIABILITIES AND EQUITY										
Long-Term Debt	295	290	330	330	330	330	330	330	330	310
Current and Other Liabilities	99	96	67	65	64	54	51	49	47	65
Contributions in Aid of Construction	35	45	45	45	44	45	44	43	42	41
Share Capital	121	121	121	121	121	121	121	121	121	121
Retained Earnings	36	41	(27)	(4)	21	47	72	95	117	136
	586	594	536	557	580	597	618	639	657	674

GAS OPERATIONS (CGM12)
PROJECTED CASH FLOW STATEMENT
Capital Coverage Ratio Greater than 1.0 for 2015 and beyond
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES										
Cash Receipts from Customers	355	357	401	406	411	411	411	411	412	413
Cash Paid to Suppliers and Employees	(291)	(335)	(347)	(348)	(349)	(349)	(350)	(351)	(353)	(355)
Interest Paid	(19)	(19)	(20)	(21)	(22)	(22)	(21)	(21)	(21)	(21)
	45	3	33	37	40	41	40	39	38	37
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	60	30	40	-	-	-	-	-	-	-
Retirement of Long-Term Debt	(63)	-	(35)	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	(3)	30	5	-	-	-	-	-	-	-
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(37)	(39)	(33)	(37)	(40)	(32)	(33)	(33)	(34)	(34)
Other	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
	(37)	(39)	(33)	(38)	(41)	(34)	(34)	(34)	(34)	(35)
Net Increase (Decrease) in Cash	5	(7)	5	(1)	(1)	7	6	5	4	2
Cash at Beginning of Year	(13)	(9)	(15)	(10)	(11)	(11)	(5)	2	7	11
Cash at End of Year	(9)	(15)	(10)	(11)	(11)	(5)	2	7	11	12

<u>PUB/CENTRA II-144</u>

Reference: PUB/Centra I-11

a) Please file the 2009/10 & 2010/11 GRA Compliance Filing of February 19, 2010 in response to Order 128/09.

<u>ANSWER</u>:

Please see the Attachment 1 to this response. Subsequent to the Compliance Filing of February 19, 2010, the PUB issued Order 41/10 which included direction with respect to non-gas costs flowing from the 2009/10 & 2010/11 GRA. As directed by this Order, Centra filed revised schedules for revenue requirement, forecast gas costs, and cost allocation, base and billed rates, and customer bill impacts that reflect the Order 41/10 directives. Please see Attachment 2 to this response for Centra's April 29, 2010 Compliance Filing. Subsequently, a revision was made to the cost allocation schedules to reflect a minor change in working capital. Please see Attachment 3 to this response for Centra's April 30, 2010 filing.

Manitoba Hydro
PO Box 815 • Winnipeg Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 22rd floor – 360 Portage Avenue
Telephone / N° de téléphone : (204) 360-3468 • Fax / N° de télécopieur : (204) 360-6147
mmurphy@hydro.mb.ca

February 19, 2010

THE PUBLIC UTILITIES BOARD OF MANITOBA
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

ATTENTION: Mr. G. Gaudreau, Executive Director

Dear Mr. Gaudreau:

Re: CENTRA GAS MANITOBA INC. ("Centra")
2009/10 & 2010/11 General Rate Application
Revised Rate Base, Revenue Requirement, Rate and Customer Bill Impact Schedules Flowing from Order 128/09

On September 16, 2009 the Manitoba Public Utilities Board ("PUB") issued Order 128/09 with respect to Centra's 2009/10 & 2010/11 General Rate Application. In that Order, the PUB directed Centra to file revised calculations and schedules for Rate Base, Revenue Requirement, Rates, and customer class bill impacts that reflect the directives of the Order. Centra has prepared the schedules and is seeking approval of the attached schedules in order to implement new Sales and Transportation Rates on May 1, 2010. The revised Rate Base and Revenue Requirement schedules are found in Attachment "A" and the revised Cost Allocation, Rate Schedules and Bill Impacts are found in Attachment "B" to this letter.

On December 18, 2009, Centra filed its 2010/11 Cost of Gas Application with the PUB, which seeks approval of rates related to changes to non-Primary Gas costs for the 2009/10 gas year. In that Application, Centra is seeking approval to change Supplemental Gas, Transportation (to Centra) and Distribution (to Customers) rates (the latter to reflect changes in Unaccounted-for-Gas) and to have those changes implemented in the form of new Sales and Transportation Rates for all gas delivered on and after May 1, 2010.

Centra's proposed Sales and Transportation Rates for May 1, 2010 as filed in Centra's 2010/11 Cost of Gas Application, incorporate the non-gas rate changes flowing from Order 128/09 as described in this letter in addition to the revised non-Primary Gas rates requested in that Application.

Revenue Requirement

Centra has adjusted its Revenue Requirement for both the 2009/10 and 2010/11 Test Years as directed by the PUB in Order 128/09. The revised Rate Base and Revenue Requirement Schedules are found in Attachment "A" to this letter. Schedule 3.1.0 provides the summary of the revised Revenue Requirement for both Test Years.

The revised Revenue Requirement for the 2009/10 Test Year, as shown at Columns 2 and 3 on Schedule 3.1.0 reflect the impact of the directives on page 135 of the Order:

- A reduction in Finance Expense of $1.1 million to reflect an adjustment to short term and long term interest rates, as per Directive 3(a);
- An increase to Revenue Requirement to include the $3.8 million Furnace Replacement Program as per Directive 3(b), and;
- A reduction in Amortization Expense of $3.5 million to reflect a 10 year amortization of DSM expenditures, as per Directive 3(d).

The revised Revenue Requirement for the 2010/11 Test Year, as shown at Columns 5 and 6 on Schedule 3.1.0, reflects the impact of the directives on page 135 of the Order:

- A reduction in Finance Expense of $1.8 million to reflect an adjustment to short term and long term interest rates, as per Directive 3(a);
- An increase to Revenue Requirement to include the $3.8 million Furnace Replacement Program as per Directive 3(b);
- The removal of the $5.0 million accounting provision for IFRS which results in a $3.0 million Net Income, as per Directive 3(c), and;
- A reduction in Amortization Expense of $4.9 million to reflect a 10 year amortization of DSM expenditures, as per Directive 3(d).

Revised Schedule 4.0.0 provided in Attachment "A" to this letter indicates that the total Revenue Requirement for the 2009/10 Test Year is $462.3 million. Of that amount, $318.8 million is related to an estimate of the gas costs as of April 1, 2009 for the 2009/10 Fiscal Year, and $143.6 million is related to the non-gas cost Revenue Requirement. The Revenue Requirement for the 2010/11 Test Year is shown on Schedule 4.0.0 as $478.5 million. Of that amount, $331.4 million is related to an estimate of gas costs as of April 1, 2009 for the 2010/11 Fiscal Year, and $147.0 million is related to non-gas cost amounts in Revenue Requirement.

Cost Allocation and Rate Matters

As noted at the 2009/10 & 2010/11 General Rate Application, Centra applied to transition the management of its gas deferral accounts from a Fiscal Year to a Gas Year period. Consequently, in the Cost Allocation section, found at Tab 9 of the Application, Centra provided tables that reconciled the removal of the 2010/11 Fiscal Year Gas Costs and the inclusion of the 2008/09 Gas Year Costs.

Flowing from Order 128/09, Centra's 2010/11 Revenue Requirement is $478.5 million, which includes gas costs of $331.4 million on a Fiscal Year basis. The following table depicts the reconciliation of the removal of the Fiscal Year gas cost estimate of $331.4 million and the inclusion of the 2008/09 Gas Year cost estimate of $395.9 million. An additional reconciliation was made regarding net income, which is described in the section below this table. As a result, Centra is allocating a Revenue Requirement for the 2010/11 Test Year of $543.6 million for rate setting purposes.

Centra notes the PUB's comments made in Order 128/09 with respect to the adjustment of rates for 2009/10 and 2010/11. On Page 4 of the Order, the PUB states:

> *"And, as to 2010, the only change to non-Primary gas rates for Centra's SGS and LGS customer classes (the former include most residential and commercial customers, the latter primarily commercial, institutional and industrial customers) to arise out of the recent GRA hearing is to occur on May 1, 2010, when the basic monthly charges (BMC) for these classes are to increase."*

With regard to the large volume customer classes, on Page 5 of the Order, the PUB states:

> *"Rates for customers in higher volume classes (High Volume Firm, Mainline, Interruptible, Power Station and Special Contract classes) will, likewise, only change on May 1, 2010, and with those changes being in accordance with the results of Centra's previously approved cost allocation model and rate design methodology."*

In order to appropriately calculate the rates for the higher volume customer classes, Centra must allocate the adjusted Revenue Requirement which incorporates a full $3 million of Net Income. This allocation would also produce new Transportation and Distribution rates for the SGS and LGS customer classes, however, the PUB has only approved changes to the level of the BMC for those customer classes, and has ordered that the Transportation and Distribution rates be unchanged.

Centra has incorporated in rates a total Revenue Requirement of $543.6 million as shown in the table below, including $3.0 million of Net Income. It is expected that Centra will only recover approximately $2.4 million of Net Income in the 2010/11 Test Year because Centra has capped its Transportation and Distribution Rates for the SGS and LGS Classes to those approved on August 1, 2009, consistent with the PUB's direction in Order 128/09 which limits recovery of Revenue Requirement increases from the SGS and LGS Classes to an increase to the BMC.

By capping the Transportation and Distribution Rates for the SGS and LGS classes, Centra's rates for these classes are no longer at unity (that is, the revenues generated by rates for those classes do not reflect the allocation of costs for each class). Consequently, the overall revenues that are generated by these rates are expected to result in $2.4 million of Net Income as shown in line 23, column 5 on revised Schedule 3.0.0.

	2010/11 TY Per B/O 128/09 Sch 4.0.0	2010/11 TY Per B/O 128/09 Cost Allocation
Cost of Gas	331,442	395,868
Other Income	(2,026)	(2,026)
Operating & Administrative	60,343	60,343
Depreciation & Amortization	27,367	27,367
Furnace Replacement Program	3,800	3,800
Capital & Other Taxes	23,940	23,940
Finance Expense	19,257	19,257
Corporate Allocation	12,000	12,000
Net Income (Loss)	2,353	3,000
Total Cost of Service	478,476	543,550
Total Non-Gas Costs	147,035	147,682

2010/11 Total Cost of Service (Sch. 4.0.0)	478,476
Less 2010/11 Fiscal Year Cost of Gas	(331,442)
Add 2008/09 Gas Year Cost of Gas	395,868
Less Net Income per Sch 4.0.0	(2,353)
Add Net Income per Cost Allocation	3,000
2010/11 Cost Allocation (Sch. 9.2.0)	543,550

In accordance with Order 128/09, Centra has reflected the following directives in the preparation of the Schedules attached to this submission:

- The costs associated with the Furnace Replacement Program have been entirely allocated to the SGS class;
- The Basic Monthly Charge for SGS customers has been increased from $13 to $14 per month;
- The Basic Monthly Charge for LGS customers has been increased from $70 to $77 per month on May 1, 2010, as per Directive 3(e);
- The Primary Gas overhead rate of $\$1.64/10^3m^3$ will be applied as per Directive 3(f). The revised Primary Gas overhead rate was applied in the calculation of Primary Gas Rates for November 1, 2009 as approved in Order 147/09, and will be applied in the calculation of Centra's February 1, 2010 and May 1, 2010 Quarterly Primary Gas Rate Applications; and
- The Program Cost Rate for Fixed-Rate Primary Gas Service Offerings of $\$0.0262/m^3$, as per Directive 8. This Program Cost Rate was used in Centra's October 9, 2009 Fixed-Rate Primary Gas offering and will be applied to each of Centra's future Fixed-Rate Primary Gas offerings until further order of the PUB.

Rate Schedules

Centra has included revised rate schedules for May 1, 2010 as shown on Schedule 10.2.1, pages 1 to 4. Centra has not provided revised rate schedules for the 2009/10 Test Year, as there were no non-gas rate changes approved for the 2009/10 Fiscal Year period, as noted previously in this correspondence. The PUB approved changes to Transportation and Distribution Rates reflective of non-Primary Gas cost changes in Order 116/09 effective August 1, 2009.

The attached rate schedules reflect the increase in the Basic Monthly Charge for SGS and LGS classes in addition to maintaining the August 1, 2009 PUB approved Transportation and Distribution Rates. The rates for the HVF, Mainline, Co-op, Special Contract, Power Station and Interruptible classes reflect their fully allocated costs as determined by the Cost of Service Study.

Bill Impacts – May 1, 2010

All adjustments to rates made in accordance with Order 128/09 have been reflected in Bill Impact Schedule 10.1.1. included in Attachment "B". The impact to the typical residential customer as a result of Order 128/09 is an increase of approximately 1.1% or $12 on an annual gas bill. The impacts to lower volume residential customers will be greater than those experienced by the typical residential customer because of the increase in the BMC. An increase in the level of the BMC will shift costs from customers with higher consumption to customers with lower consumption within the class. The combined impacts for larger volume customers range from an increase of 0.4% to a decrease of 1.2%. The Special Contract and Power Station classes will have increases of 6.0% and 14.7% respectively, as shown in the table below.

2010/11 Test Year			Annual Impacts Billed Rates	
Customer Class	Consumption (10^3M^3)	Load Factor	$ Impact	% Change
SGS	11.3		$12	0.3%
	2.5		$12	1.1%
	1.0		$12	2.4%
LGS	679.9		$84	0.0%
	11.3		$84	2.0%
HVF	2,833	40%	($3,588)	-0.4%
	850	75%	($172)	-0.1%
Mainline	28,328	40%	($95,952)	-1.2%
	2,833	75%	$2,882	0.4%
Special Contract	451,570	94%	$103,010	6.0%
Power Stations	12,117	4%	$106,139	14.7%
Interruptible	850	25%	($2,219)	-0.9%
	850	75%	($1,467)	-0.6%

Copies of this letter have been provided to the PUB advisors and all registered interveners from Centra's 2009/10 & 2010 General Rate Application. If you have any questions with respect to this submission, or require a paper copy, please contact the writer at 360-3468 or Greg Barnlund at 360-5243.

Yours truly,
MANITOBA HYDRO LAW DEPARTMENT
Per:

M Murphy

Marla D. Murphy
Barrister & Solicitor
Att.

cc Mr. B. Peters, Fillmore Riley
Mr. R. Cathcart, Cathcart Advisors Inc.
Mr. B. Ryall, Energy Consultants Inc.
Registered Intervenors

Centra Gas Manitoba Inc.
Reflecting Order 128/09
Tab 3 - Schedule Index

CENTRA GAS MANITOBA INC.
Summary of Additional Revenue Requested

Schedule 3.0.0
Reflecting Order 128/09

2009/10 and 2010/11 Test Year

($000'S)
Feb 19, '10

Line		2008/09 Approved	2009/10 Test Year	Net Change	2008/09 Approved	2010/11 Test Year	Net Change
5		[1]	[2]	[3]	[4]	[5]	[6]
7	Cost of Gas	407,142	318,785	(88,357)	407,142	331,442	(75,700)
9	Other Income	(2,115)	(2,026)	89	(2,115)	(2,026)	89
11	Operating & Administrative	58,000	59,160	1,160	58,000	60,343	2,343
13	Depreciation & Amortization	23,072	25,047	1,975	23,072	27,367	4,295
15	Furnace Replacement Program	3,855	3,800	(55)	3,855	3,800	(55)
17	Capital & Other Taxes	23,063	23,703	640	23,063	23,940	877
19	Finance Expense	22,154	19,893	(2,261)	22,154	19,257	(2,897)
21	Corporate Allocation	12,000	12,000	-	12,000	12,000	-
23	Net Income (Loss)	3,000	1,979	(1,021)	3,000	2,353	(647)
25	Revenue Requirement	550,171	462,341	(87,830)	550,171	478,476	(71,694)

CENTRA GAS MANITOBA INC.
Summary of Revenue Requirement
Cost of Service Methodology

Schedule 3.1.0
Reflecting Order 128/09

($000'S)

2009/10 and 2010/11 Test Year

Feb 19, '10

	2009/10 Applied[1]	2009/10 Test Year	Net Change	2010/11 Applied[1]	2010/11 Test Year	Net Change
	[1]	[2]	[3]	[4]	[5]	[6]
Cost of Gas	318,785	318,785	-	331,442	331,442	-
Other Income	(2,026)	(2,026)	-	(2,026)	(2,026)	-
Operating & Administrative	59,160	59,160	-	60,343	60,343	-
Depreciation & Amortization	28,545	25,047	(3,498)	32,285	27,367	(4,918)
Capital & Other Taxes	23,701	23,703	2	23,934	23,940	6
Finance Expense	20,992	19,893	(1,099)	21,017	19,257	(1,760)
Furnace Replacement Program	-	3,800	3,800	-	3,800	3,800
Provision for Accounting & Other Changes	-	-	-	5,000	-	(5,000)
Corporate Allocation	12,000	12,000	-	12,000	12,000	-
Net Income (Loss)	2,869	1,979	(890)	2,814	2,353	(461)
Revenue Requirement	464,026	462,341	(1,685)	486,808	478,476	(8,332)

[1] This is based on the May 29th, 2009 Update Filing

CENTRA GAS MANITOBA INC. — **Schedule 3.1.1**
Summary of Revenue Requirement & Rate Base — **Reflecting Order 128/09**
Rate Base Rate of Return Methodology
($000'S)
2009/10 and 2010/11 Test Year — **Feb 19, '10**

	2009/10 Applied(1)	2009/10 Test Year	Net Change	2010/11 Applied(1)	2010/11 Test Year	Net Change
	[1]	[2]	[3]	[4]	[5]	[6]
Cost of Gas	318,785	318,785	-	331,442	331,442	-
Other Income	(2,026)	(2,026)	-	(2,026)	(2,026)	-
Operating & Administrative	59,160	59,160	-	60,343	60,343	-
Depreciation & Amortization	28,545	25,047	(3,498)	32,285	27,367	(4,918)
Capital & Other Taxes	23,701	23,703	2	23,934	23,940	6
Furnace Replacement Program	-	3,800	3,800	-	3,800	3,800
Provision for Accounting & Other Changes	-	-	-	5,000	-	(5,000)
Corporate Allocation	12,000	12,000	-	12,000	12,000	-
Return on Rate Base	33,334	32,929	(405)	34,180	32,399	(1,781)
Revenue Requirement	473,501	473,398	(101)	497,158	489,266	(7,893)
Gas Plant in Service	611,116	611,116	-	634,052	634,052	-
Accumulated Depreciation	(216,739)	(216,739)	-	(229,807)	(229,807)	-
Net Plant	394,377	394,377	-	404,245	404,245	-
Contributions in Aid of Construction	(48,857)	(48,857)	-	(50,956)	(50,956)	-
Working Capital Allowance	117,939	117,955	16	133,315	132,556	(759)
Rate Base	463,459	463,475	16	486,603	485,844	(759)

(1) This is based on the May 29th, 2009 Update Filing

Centra Gas Manitoba Inc.
Reflecting Order 128/09
Tab 4 - Schedule Index

CENTRA GAS MANITOBA INC.
Summary of Cost of Service

2009/10 and 2010/11 Test Year

Schedule 4.0.0
Reflecting Order 128/09
($000'S)
Feb 19, '10

	2006/07 Actual	2007/08 Actual	2008/09 Forecast	2009/10 Test Year	2010/11 Test Year
	[1]	[2]	[3]	[4]	[5]
Cost of Gas	378,664	386,490	427,856	318,785	331,442
Other Income	(2,199)	(1,967)	(2,054)	(2,026)	(2,026)
Operating & Administrative	53,505	56,270	58,000	59,160	60,343
Depreciation & Amortization	18,323	23,293	25,413	25,047	27,367
Capital & Other Taxes	22,248	23,021	23,323	23,703	23,940
Finance Expense	22,095	21,711	22,225	19,893	19,257
Furnace Replacement Program	-	-	-	3,800	3,800
Corporate Allocation	12,000	12,000	12,000	12,000	12,000
Net Income (Loss)	1,075	5,899	3,038	1,979	2,353
Total Cost of Service	505,711	526,717	569,801	462,341	478,476
Less Cost of Gas	378,664	386,490	427,856	318,785	331,442
Non-Gas Cost of Service	127,047	140,228	141,945	143,556	147,034
% Change		10.4%	1.2%	1.1%	2.4%

CENTRA GAS MANITOBA INC. **Schedule 4.1.3**
Revenue at Proposed Rates **Reflecting Order 128/09**
($000'S)
2009/10 Test Year **Feb 19, '10**

	System	WTS	T-Service	2009/10 Total
	[1]	[2]	[3]	[4]
SGS Residential	212,267	20,450	-	232,717
SGS Commercial	32,320	1,247	-	33,567
LGS	138,337	6,898	-	145,235
High Volume Firm	29,930	3,022	551	33,503
Mainline Firm	499	1,863	1,268	3,630
Interruptible Sales	24,468	961	369	25,798
Power Stations	-	-	1,018	1,018
Special Contract	-	-	1,732	1,732
Total	437,821	34,440	4,939	477,201
Baseload Increment Charges				154
Total Revenue (1)				477,355
Other:				
Rate Rider Amortization				(15,014)
Total Revenue				462,341

(1) Revenue at April 1, 2009 strip rates

CENTRA GAS MANITOBA INC. **Schedule 4.1.4**
Revenue at Proposed Rates **Reflecting Order 128/09**
($000'S)

2010/11 Test Year **Feb 19, '10**

	System	WTS	T-Service	2010/11 Total
	[1]	[2]	[3]	[4]
SGS Residential	211,251	20,426	-	231,677
SGS Commercial	32,124	1,241	-	33,365
LGS	137,435	6,866	-	144,301
High Volume Firm	30,084	3,059	562	33,705
Mainline Firm	502	1,903	1,302	3,707
Interruptible Sales	25,057	979	376	26,412
Power Stations	-	-	1,018	1,018
Special Contract	-	-	1,732	1,732
Total Revenue	436,453	34,475	4,990	475,918
Baseload Increment Charges				154
Total Revenue [1]				476,072
Other:				
Rate Rider Amortization				(1,061)
Additional Basic Monthly Charge SGS				2,859
Additional Basic Monthly Charge LGS				606
Total Revenue				478,476

[1] Revenue at April 1, 2009 strip rates

CENTRA GAS MANITOBA INC. **Schedule 4.8.3**
Reconciliation of Depreciation and Amortization Expense to Income Statement **Reflecting Order 128/09**
($000'S)
2009/10 Test Year **Feb 19, '10**

	2009/10 Forecast
	[1]
Net Depreciation Expense to Income Statement	
Depreciation Expense per Schedule 4.9.3	17,495
Amortization of Customers' Contributions per Schedule 5.5.3	(996)
Depreciation on Common Assets	4,110
Amortization Expense per Schedule 4.10.3	4,438
Depreciation and Amortization Expense per Financial Statements	25,047

CENTRA GAS MANITOBA INC. **Schedule 4.8.4**
Reconciliation of Depreciation and Amortization Expense to Income Statement **Reflecting Order 128/09**
($000'S)
2010/11 Test Year **Feb 19, '10**

	2010/11 Test Year
	[1]
Net Depreciation Expense to Income Statement	
Depreciation Expense per Schedule 4.9.4	18,144
Amortization of Customers' Contributions per Schedule 5.5.4	(996)
Depreciation on Common Assets	4,251
Amortization Expense per Schedule 4.10.4	5,968
Depreciation and Amortization Expense per Financial Statements	27,367

CENTRA GAS MANITOBA INC. **Schedule 4.10.3**

Amortization Expense **Reflecting Order 128/09**

($000'S)

2009/10 Test Year **Feb 19, '10**

	Balance Mar 31/09	Additions	Amortization	Balance Mar 31/10
	[1]	[2]	[3]	[4]
Gas Supply Portfolio Optimization	128	-	96	32
General Rate Applications	-	846	423	423
Shoal Lake Expansion	49	-	19	30
Gas Deferred Site Clean-up	2,048	-	165	1,883
Competitive Landscape Proceedings	474	-	119	355
Gas Supply Acquisition Contracting	54	-	21	33
Fixed Rate Primary Gas Service	478	-	96	382
Deferred Charges	3,231	846	939	3,138
Investment in Demand Side Management	28,144	14,193	3,499	38,838
Total	31,375	15,039	4,438	41,976

CENTRA GAS MANITOBA INC. **Schedule 4.10.4**

Amortization Expense **Reflecting Order 128/09**

($000'S)

2010/11 Test Year **Feb 19, '10**

	Balance Mar 31/10	Additions	Amortization	Balance Mar 31/11
	[1]	[2]	[3]	[4]
Gas Supply Portfolio Optimization	32	-	32	-
Cost of Gas Hearings	-	527	176	351
General Rate Applications	423	-	423	-
Shoal Lake Expansion	30	-	20	10
Gas Deferred Site Clean-up	1,883	-	165	1,718
Competitive Landscape Proceedings	355	-	117	238
Gas Supply Acquisition Contracting	33	-	21	12
Fixed Rate Primary Gas Service	382	-	96	286
Deferred Charges	3,138	527	1,050	2,615
Investment in Demand Side Management	38,838	13,312	4,918	47,232
Total	41,976	13,839	5,968	49,847

CENTRA GAS MANITOBA INC.
Capital and Other Taxes - 2006/07 to 2010/11

Schedule 4.11.0
Reflecting Order 128/09
($000'S)
Feb 19, '10

	2006/07 Actual	2007/08 Actual	2008/09 Forecast	2009/10 Test Year	2010/11 Test Year
	[1]	[2]	[3]	[4]	[5]
Municipal Taxes	14,223	15,024	15,355	15,357	15,665
Payroll Tax	616	653	716	770	781
Taxes on Common Assets	(97)	(79)	(1)	209	218
Corporation Capital Tax	2,414	2,477	2,453	2,713	2,769
Capital & Other Taxes	17,156	18,075	18,523	19,049	19,432
Income Taxes[(1)]	5,092	4,946	4,800	4,654	4,508
Total Taxes	22,248	23,021	23,323	23,703	23,940

[(1)] Calculation of Income Taxes

	2006/07 Actual	2007/08 Actual	2008/09 Forecast	2009/10 Test Year	2010/11 Test Year
Opening Balance	41,497	39,693	37,888	36,084	34,280
Ending Balance	39,693	37,888	36,084	34,280	32,476
Average Balance	40,595	38,791	36,986	35,182	33,378
Amortizatior	1,804	1,804	1,804	1,804	1,804
Carrying Costs on Average Balance	3,288	3,142	2,996	2,850	2,704
Income Taxes	5,092	4,946	4,800	4,654	4,508

CENTRA GAS MANITOBA INC.
Finance Expense - 2006/07 to 2010/11

Schedule 4.12.0
Reflecting Order 128/09
($000'S)
Feb 19, '10

	2006/07 Actual	2007/08 Actual	2008/09 Forecast	2009/10 Test Year	2010/11 Test Year
	[1]	[2]	[3]	[4]	[5]
Interest on Long Term Debt/Advances	13,762	13,547	13,760	14,928	14,404
Provincial Guarantee Fee on Long Term Debt	2,476	2,403	2,380	2,657	2,977
Amortization of Debt Discounts	1,692	1,253	1,256	1,262	298
Interest on Short Term Debt	3,349	4,665	4,384	511	879
Provincial Guarantee Fee on Short Term Debt	603	815	902	628	669
Interest on Common Assets	2,138	2,244	2,562	2,677	2,839
Interest on Inventory	24	32	24	25	27
Interest Capitalized	(1,958)	(3,270)	(3,101)	(2,826)	(2,843)
Other	9	22	58	31	7
Total Financing Expenses	22,095	21,711	22,225	19,893	19,257

Centra Gas Manitoba Inc.
Reflecting Order 128/09
Tab 5 - Schedule Index

CENTRA GAS MANITOBA INC.
Summary of Rate Base Rate of Return
Revenue Requirement & Rate Base

Schedule 5.0.0
Reflecting Order 128/09
($000'S)
Feb 19, '10

	2006/07 Actual	2007/08 Actual	2008/09 Forecast	2009/10 Test Year	2010/11 Test Year
	[1]	[2]	[3]	[4]	[5]
Cost of Gas	378,664	386,490	427,856	318,785	331,442
Other Income	(2,199)	(1,967)	(2,054)	(2,026)	(2,026)
Operating & Administrative	53,505	56,270	58,000	59,160	60,343
Depreciation & Amortization	18,323	23,293	25,413	25,047	27,367
Capital & Other Taxes	22,248	23,021	23,323	23,703	23,940
Furnace Replacement Program	-	-	-	3,800	3,800
Corporate Allocation	12,000	12,000	12,000	12,000	12,000
Return on Rate Base	34,757	33,039	34,704	32,929	32,399
Revenue Requirement from Gas Rates	517,298	532,146	579,242	473,398	489,266

Gas Plant in Service	545,841	565,585	586,411	611,116	634,052
Accumulated Depreciation	(186,170)	(195,010)	(205,391)	(216,739)	(229,807)
Net Plant	359,671	370,575	381,020	394,377	404,245
Contributions in Aid of Construction	(46,639)	(46,974)	(46,450)	(48,857)	(50,956)
Working Capital Allowance	118,603	107,195	123,012	117,955	132,556
Rate Base	431,635	430,796	457,582	463,475	485,844

CENTRA GAS MANITOBA INC. **Schedule 5.6.3**
Working Capital Allowance **Reflecting Order 128/09**
($000'S)
2009/10 Test Year **Feb 19, '10**

	2009/10 Test Year	Daily Amounts (Col 1 / 365)	Lead (Lag) Days	Working Capital Required (Col 2 * Col 3)
	[1]	[2]	[3]	[4]
Cash Working Capital Requirement:				
Revenues	475,424	1,303	47.8	62,209
Cost of Gas	318,785	873	(39.2)	(34,263)
Operating and Administrative Expenses	56,554	155	(15.2)	(2,355)
Payroll Taxes	770	2	(15.2)	(32)
Capital and Other Taxes	18,279	50	(17.7)	(885)
Financing Expenses:				
Cost of Long Term Debt	19,740	54	(91.3)	(4,935)
Cost of Short Term Debt	1,195	3	(16.5)	(54)
Corporate Allocation	12,000	33	(15.2)	(500)
Cash Revenue Requirement Items	427,324	1,171	16.4	19,184
Reconciling Revenue Requirement Items:				
Bad Debt Expense	2,606			
Depreciation and Amortization Expense	25,047			
Furnace Replacement Program	3,800			
Income Taxes	4,654			
Return on Equity	11,993			
Total Revenue Requirement	475,424			
Non Cost of Service Tax Collections	48,815	134	1.0	132
Cash Working Capital Requirement				19,317
Other Working Capital Requirements:				
Gas in Storage				68,033
Security Deposits				(500)
Investment in DSM				31,105
Total Working Capital Allowance				117,955

CENTRA GAS MANITOBA INC. **Schedule 5.6.4**

Working Capital Allowance **Reflecting Order 128/09**

($000'S)

2010/11 Test Year **Feb 19, '10**

	2010/11 Test Year	Daily Amounts (Col 1 / 365)	Lead (Lag) Days	Working Capital Required (Col 2 * Col 3)
	[1]	[2]	[3]	[4]
Cash Working Capital Requirement:				
Revenues	491,291	1,346	47.8	64,285
Cost of Gas	331,442	908	(39.2)	(35,623)
Operating and Administrative Expenses	57,685	158	(15.2)	(2,402)
Payroll Taxes	781	2	(15.2)	(33)
Capital and Other Taxes	18,651	51	(17.7)	(903)
Financing Expenses:				
Cost of Long Term Debt	18,822	52	(91.3)	(4,705)
Cost of Short Term Debt	1,440	4	(16.5)	(65)
Corporate Allocation	12,000	33	(15.2)	(500)
Cash Revenue Requirement Items	440,821	1,208	16.6	20,053
Reconciling Revenue Requirement Items:				
Bad Debt Expense	2,658			
Depreciation and Amortization Expense	27,367			
Furnace Replacement Program	3,800			
Income Taxes	4,508			
Return on Equity	12,137			
Total Revenue Requirement	491,291			
Non Cost of Service Tax Collections	50,321	138	1.0	136
Cash Working Capital Requirement				20,190
Other Working Capital Requirements:				
Gas in Storage				75,808
Security Deposits				(500)
Investment in DSM				37,058
Total Working Capital Allowance				132,556

CENTRA GAS MANITOBA INC.
Overall Rate of Return

Schedule 5.7.3
Reflecting Order 128/09
($000'S)

2009/10 Test Year

Feb 19, '10

	Capital Structure	Weight	Cost Rate	Weighted Cost of Capital
	[1]	[2]	[3]	[4]
Long Term Debt	265,835	51.9%	7.09%	3.68%
Short Term Debt	88,156	17.2%	1.50%	0.26%
Equity	158,688	31.0%	8.36%	2.59%
	512,680	100.0%		6.52%

CENTRA GAS MANITOBA INC.
Overall Rate of Return

2010/11 Test Year

Schedule 5.7.4
Reflecting Order 128/09
($000'S)
Feb 19, '10

		Capital Structure	Weight	Cost Rate	Weighted Cost of Capital
1					
4		[1]	[2]	[3]	[4]
5					
6					
7					
8	Long Term Debt	297,671	55.3%	5.94%	3.28%
9					
10	Short Term Debt	79,768	14.8%	2.00%	0.30%
11					
12	Equity	160,854	29.9%	8.36%	2.50%
13					
14		538,293	100.0%		6.08%

CENTRA GAS MANITOBA INC.
13 Month Average Debt Financing

2009/10 Test Year

Schedule 5.8.3
Reflecting Order 128/09
($000'S)
Feb 19, '10

Line	Principal Balances	Principal at	Principal at	30	31	30	31	31	30	31	30	31	31	28	31	365
3	Debt Code	Start of Year	End of Year	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Monthly Average
4		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
6	CG 1	62,671	62,671	1,880,118	1,942,789	1,880,118	1,942,789	1,942,789	1,880,118	1,942,789	1,880,118	1,942,789	1,942,789	1,754,777	1,942,789	62,671
7	CG 4	18,077	0	542,316	560,393	542,316	560,393	560,393	542,316	560,393	542,316	560,393	560,393	506,162	542,316	18,028
8	CG 5 (EM 3 & 4)	75,000	0	2,250,000	2,325,000	2,250,000	2,325,000	2,325,000	2,250,000	2,325,000	2,250,000	2,325,000	2,325,000	1,575,000	0	67,192
9	CG 7 - (Refinance CG 3)	50,000	50,000	1,500,000	1,550,000	1,500,000	1,550,000	1,550,000	1,500,000	1,550,000	1,500,000	1,550,000	1,550,000	1,400,000	1,550,000	50,000
10	CG 8 - (CG 6 Extension)	30,000	30,000	900,000	930,000	900,000	930,000	930,000	900,000	930,000	900,000	930,000	930,000	840,000	930,000	30,000
11	New Issue March 2009	30,000	30,000	900,000	930,000	900,000	930,000	930,000	900,000	930,000	900,000	930,000	930,000	840,000	930,000	30,000
12	New Issue March 2010	0	30,000	0	0	0	0	0	0	0	0	0	0	0	30,000	82
13	New Issue (Refinance CG 5)	0	75,000	0	0	0	0	0	0	0	0	0	0	525,000	2,325,000	7,808
14	New Issue (Refinance CG 4)	0	20,000	0	0	0	0	0	0	0	0	0	0	0	20,000	55
16	Balances at April 1 and March 31	265,748	297,671													
18	Monthly Debt Balances Weighted by Day			7,972,434	7,308,182	7,072,434	7,308,182	7,308,182	7,072,434	7,308,182	7,072,434	7,308,182	7,308,182	6,075,938	4,965,105	
20	Average Monthly Debt Balance			265,748	265,748	265,748	265,748	265,748	265,748	265,748	265,748	265,748	265,748	265,748	266,778	265,835

Line		Interest Expense	
25	Financing Costs on Debt	Long Term	Short Term
27	CG 1	3,792	
28	CG 4	997	
29	CG 5 (EM 3 & 4)	4,212	
30	CG 7 - (Refinance CG 3)	2,253	
31	CG 8 - (CG 6 Extension)	1,890	
32	New Issue March 2009	1,470	
33	New Issue March 2010	0	
34	New Issue (Refinance CG 5)	312	
35	New Issue (Refinance CG 4)	3	
37	Provincial Guarantee Fee	2,657	
39	Sub-total of Debt Financing Cost	17,585	
41	Amortization of Redemption Premium	1,262	
43	Net Cost of Debt Financing	18,847	
45	Embedded Cost of Long Term and Short Term Debt	7.09%	1.50%

CENTRA GAS MANITOBA INC.
13 Month Average Debt Financing

2010/11 Test Year

Schedule 5.8.4
Reflecting Order 128/09
($000'S)
Feb 19, '10

Principal Balances	Principal at	Principal at	30	31	30	31	31	30	31	30	31	31	28	31	365
Debt Code	Start of Year	End of Year	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Monthly Average
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
CG 1	62,671	62,671	1,880,118	1,942,789	1,880,118	1,942,789	1,942,789	1,880,118	1,942,789	1,880,118	1,942,789	1,942,789	1,754,777	1,942,789	62,671
CG 7 - (Refinance CG 3)	50,000	50,000	1,500,000	1,550,000	1,500,000	1,550,000	1,550,000	1,500,000	1,550,000	1,500,000	1,550,000	1,550,000	1,400,000	1,550,000	50,000
CG 8 - (CG 6 Extension)	30,000	30,000	900,000	930,000	900,000	930,000	930,000	900,000	930,000	900,000	930,000	930,000	840,000	930,000	30,000
New Issue March 2009	30,000	30,000	900,000	930,000	900,000	930,000	930,000	900,000	930,000	900,000	930,000	930,000	840,000	930,000	30,000
New Issue March 2010	30,000	30,000	900,000	930,000	900,000	930,000	930,000	900,000	930,000	900,000	930,000	930,000	840,000	930,000	30,000
New Issue (Refinance CG 5)	75,000	75,000	2,250,000	2,325,000	2,250,000	2,325,000	2,325,000	2,250,000	2,325,000	2,250,000	2,325,000	2,325,000	2,100,000	2,325,000	75,000
New Issue (Refinance CG 4)	20,000	20,000	600,000	620,000	600,000	620,000	620,000	600,000	620,000	600,000	620,000	620,000	560,000	620,000	20,000
Balances at April 1 and March 31	297,671	297,671													
Monthly Debt Balances Weighted by Day			8,930,118	9,227,789	8,930,118	9,227,789	9,227,789	8,930,118	9,227,789	8,930,118	9,227,789	9,227,789	8,334,777	9,227,789	
Average Monthly Debt Balance			297,671	297,671	297,671	297,671	297,671	297,671	297,671	297,671	297,671	297,671	297,671	297,671	297,671

	Interest Expense	
Financing Costs on Debt	Long Term	Short Term
CG 1	3,792	
CG 7 - (Refinance CG 3)	2,253	
CG 8 - (CG 6 Extension)	1,890	
New Issue March 2009	1,470	
New Issue March 2010	1,200	
New Issue (Refinance CG 5)	3,000	
New Issue (Refinance CG 4)	800	
Provincial Guarantee Fee	2,977	
Sub-total of Debt Financing Cost	17,381	
Amortization of Redemption Premium	298	
Net Cost of Debt Financing	17,678	
Embedded Cost of Long Term and Short Term Debt	5.94%	2.00%

CENTRA GAS MANITOBA INC. **Schedule 5.9.3**
Return on Rate Base **Reflecting Order 128/09**
($000'S)
2009/10 Test Year **Feb 19, '10**

Line		Rate Base	Weight	Cost Rate	Return
4		[1]	[2]	[3]	[4]
8	Long Term Debt	463,475	51.9%	7.09%	17,038
10	Short Term Debt	463,475	17.2%	1.50%	1,195
12	Equity	463,475	31.0%	8.36%	11,993
14			100.0%		30,227
16	Interest on Common Assets and Inventory				2,702
18	Total Return on Rate Base				32,929

CENTRA GAS MANITOBA INC. **Schedule 5.9.4**
Return on Rate Base **Reflecting Order 128/09**
($000'S)
2010/11 Test Year **Feb 19, '10**

	Rate Base	Weight	Cost Rate	Return
	[1]	[2]	[3]	[4]
Long Term Debt	485,844	55.3%	5.94%	15,956
Short Term Debt	485,844	14.8%	2.00%	1,440
Equity	485,844	29.9%	8.36%	12,137
		100.0%		29,533
Interest on Common Assets and Inventory				2,866
Total Return on Rate Base				32,399

Centra Gas Manitoba Inc.
Reflecting Order 128/09
Tab 9 - Schedule Index

Centra Gas Manitoba Inc.
2010/11 Test Year
Summary of Allocated Costs by Customer Class
Rates Reflecting Order 128/09

Schedule 9.2.0

Cost of Service Elements

SGS

	Demand	Energy	Customer	Total
Cost of Gas	17,006,199	5,198,805	0	22,205,004
Other Income	0	0	-2,002,948	-2,002,948
Operating & Maintenance Expenses	5,322,287	87,282	40,660,495	46,070,064
Depreciation & Amortization	3,394,926	8,040	21,017,604	24,420,570
Capital & Other Taxes	4,062,767	559,185	11,576,719	16,198,671
Finance Expense	2,435,553	1,433,931	8,879,179	12,748,663
Corporate Allocation	1,517,685	893,536	5,532,952	7,944,173
Net Income	379,421	223,384	1,383,238	1,986,043
Total Cost of Service	34,118,838	8,404,163	87,047,239	129,570,240

LGS

	Demand	Energy	Customer	Total
Cost of Gas	11,828,276	3,710,898	0	15,539,174
Other Income	0	0	-19,185	-19,185
Operating & Maintenance Expenses	3,703,770	62,194	5,405,461	9,171,425
Depreciation & Amortization	2,045,187	5,727	3,249,123	5,300,038
Capital & Other Taxes	2,826,674	401,859	1,955,916	5,184,449
Finance Expense	1,693,264	1,030,513	1,592,381	4,316,158
Corporate Allocation	1,055,137	642,152	992,273	2,689,561
Net Income	263,784	160,538	248,068	672,390
Total Cost of Service	23,416,092	6,013,882	13,424,037	42,854,011

HVF

	Demand	Energy	Customer	Total
Cost of Gas	2,642,130	981,724	0	3,623,854
Other Income	0	0	-1,899	-1,899
Operating & Maintenance Expenses	962,546	14,184	829,621	1,806,352
Depreciation & Amortization	478,097	1,279	217,064	696,440
Capital & Other Taxes	745,481	105,613	108,834	959,927
Finance Expense	445,741	270,901	85,250	801,892
Corporate Allocation	277,758	168,809	53,122	499,689
Net Income	69,439	42,202	13,281	124,922
Total Cost of Service	5,621,193	1,584,712	1,305,272	8,511,177

Cooperative

	Demand	Energy	Customer	Total
Cost of Gas	6,532	734	0	7,266
Other Income	0	0	-5	-5
Operating & Maintenance Expenses	1,526	22	1,792	3,340
Depreciation & Amortization	500	2	649	1,152
Capital & Other Taxes	782	220	407	1,408
Finance Expense	406	564	256	1,226
Corporate Allocation	253	351	160	764
Net Income	63	88	40	191
Total Cost of Service	10,061	1,980	3,299	15,341

Main Line

	Demand	Energy	Customer	Total
Cost of Gas	553,585	520,631	0	1,074,216
Other Income	0	0	-331	-331
Operating & Maintenance Expenses	460,185	3,330	100,583	564,099
Depreciation & Amortization	175,434	245	68,680	244,359
Capital & Other Taxes	261,724	26,608	17,386	305,719
Finance Expense	134,347	68,260	22,796	225,402
Corporate Allocation	83,717	42,535	14,205	140,457
Net Income	20,929	10,634	3,551	35,114
Total Cost of Service	1,689,921	672,243	226,871	2,589,035

Special Contract

	Demand	Energy	Customer	Total
Cost of Gas	29,768	161,111	0	190,878
Other Income	0	0	-175	-175
Operating & Maintenance Expenses	576,384	149	73,871	650,404
Depreciation & Amortization	-13,654	-15	20,704	7,035
Capital & Other Taxes	502,547	73	12,001	514,621
Finance Expense	235,701	183	7,579	243,463
Corporate Allocation	146,874	114	4,723	151,711
Net Income	36,719	28	1,181	37,928
Total Cost of Service	1,514,339	161,642	119,885	1,795,866

Power Station

	Demand	Energy	Customer	Total
Cost of Gas	7,322	316,467	0	323,789
Other Income	0	0	-407	-407
Operating & Maintenance Expenses	141,776	293	62,031	204,099
Depreciation & Amortization	-62,372	-30	83,406	21,004
Capital & Other Taxes	123,506	144	62,686	186,335
Finance Expense	57,698	359	40,214	98,272
Corporate Allocation	35,954	224	25,059	61,237
Net Income	8,988	56	6,265	15,309
Total Cost of Service	312,873	317,512	279,253	909,638

Interruptible

	Demand	Energy	Customer	Total
Cost of Gas	891,364	928,176	0	1,819,540
Other Income	0	0	-840	-840
Operating & Maintenance Expenses	359,549	11,200	377,398	748,146
Depreciation & Amortization	176,400	981	82,562	259,943
Capital & Other Taxes	280,136	82,988	53,166	416,290
Finance Expense	166,847	212,866	36,435	416,148
Corporate Allocation	103,969	132,645	22,704	259,318
Net Income	25,992	33,161	5,676	64,829
Total Cost of Service	2,004,257	1,402,016	577,100	3,983,374

Primary Gas

	Demand	Energy	Customer	Total
Cost of Gas	0	333,046,453	0	333,046,453
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	804,522	0	804,522
Depreciation & Amortization	0	77,874	0	77,874
Capital & Other Taxes	0	159,290	0	159,290
Finance Expense	0	382,549	0	382,549
Corporate Allocation	0	238,380	0	238,380
Net Income	0	59,595	0	59,595
Total Cost of Service	0	334,768,662	0	334,768,662

Supplemental Gas - Firm

	Demand	Energy	Customer	Total
Cost of Gas	0	4,221,998	0	4,221,998
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	9,551	0	9,551
Depreciation & Amortization	0	925	0	925
Capital & Other Taxes	0	2,009	0	2,009
Finance Expense	0	4,844	0	4,844
Corporate Allocation	0	3,018	0	3,018
Net Income	0	755	0	755
Total Cost of Service	0	4,243,099	0	4,243,099

Supplemental Gas - Interruptible

	Demand	Energy	Customer	Total
Cost of Gas	0	7,978,629	0	7,978,629
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	18,050	0	18,050
Depreciation & Amortization	0	1,747	0	1,747
Capital & Other Taxes	0	3,796	0	3,796
Finance Expense	0	9,154	0	9,154
Corporate Allocation	0	5,704	0	5,704
Net Income	0	1,426	0	1,426
Total Cost of Service	0	8,018,507	0	8,018,507

Fixed Price Offering

	Demand	Energy	Customer	Total
Cost of Gas	0	5,837,350	0	5,837,350
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	293,421	0	293,421
Depreciation & Amortization	0	136,402	0	136,402
Capital & Other Taxes	0	7,536	0	7,536
Finance Expense	0	9,609	0	9,609
Corporate Allocation	0	5,988	0	5,988
Net Income	0	1,497	0	1,497
Total Cost of Service	0	6,291,802	0	6,291,802

Unassigned

	Demand	Energy	Customer	Total
Cost of Gas	0	0	0	0
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	0	0	0
Depreciation & Amortization	0	0	0	0
Capital & Other Taxes	0	0	0	0
Finance Expense	0	0	0	0
Corporate Allocation	0	0	0	0
Net Income	0	0	0	0
Total Cost of Service	0	0	0	0

Total

	Demand	Energy	Customer	Total
Cost of Gas	32,965,175	362,902,976	0	395,868,151
Other Income	0	0	-2,025,790	-2,025,790
Operating & Maintenance Expenses	11,528,024	1,304,197	47,511,252	60,343,473
Depreciation & Amortization	6,194,518	233,176	24,739,792	31,167,487
Capital & Other Taxes	8,803,617	1,349,321	13,787,115	23,940,053
Finance Expense	5,169,557	3,423,732	10,664,090	19,257,379
Corporate Allocation	3,221,346	2,133,457	6,645,197	12,000,000
Net Income	805,336	533,364	1,661,299	3,000,000
Total Cost of Service	68,687,574	371,880,223	102,982,956	543,550,753

Centra Gas Manitoba Inc.
2010/11 Test Year
Unit Cost Component Summary
Rates Reflecting Order 128/09

Schedule 9.2.1

		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 FPO
1	REVENUE REQUIREMENTS													
2	Upstream Demand ($)	34,031,243	17,582,035	12,228,718	2,729,242	6,753	564,485	0	0	920,010	0	0	0	0
3	Upstream Commodity ($)	366,107,279	6,187,353	4,426,322	1,076,693	1,980	250,818	0	0	842,041	334,768,662	4,243,099	8,018,507	6,291,802
4	Upstream Customer ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Upstream Total ($)	400,138,522	23,769,388	16,655,041	3,805,935	8,733	815,303	0	0	1,762,051	334,768,662	4,243,099	8,018,507	6,291,802
6														
7	Downstream Demand ($)	34,656,331	16,536,803	11,187,374	2,891,951	3,308	1,125,436	1,514,339	312,873	1,084,247	0	0	0	0
8	Downstream Commodity ($)	5,772,944	2,216,810	1,587,560	508,019	0	421,425	161,642	317,512	559,976	0	0	0	0
9	Downstream Customer ($)	102,982,956	87,047,239	13,424,037	1,305,272	3,299	226,871	119,885	279,253	577,100	0	0	0	0
10	Downstream Total ($)	143,412,231	105,800,853	26,198,970	4,705,242	6,608	1,773,731	1,795,866	909,638	2,221,323	0	0	0	0
11														
12	Total (incl. gas costs)	543,550,753	129,570,240	42,854,011	8,511,177	15,341	2,589,035	1,795,866	909,638	3,983,374	334,768,662	4,243,099	8,018,507	6,291,802
13														0
14														
15	MONTHLY BILLING DETERMINANTS													
16	Upstream Demand (10^3m^3-day)	132,932	66,997	45,752	10,656	25	1,907	0	0	7,595	0	0	0	0
17	Upstream Commodity (10^3m^3)	1,440,669	684,811	492,165	129,386	270	32,455	0	0	101,583	1,104,846	26,782	30,475	16,755
18	Upstream Customer (customers)	3,176,415	3,081,798	92,937	1,128	12	36	0	0	504	0	0	0	38,004
19														
20	Downstream Demand (10^3m^3-day)	166,909	66,997	45,752	12,429	25	7,102	14,633	10,900	9,071	0	0	0	0
21	Downstream Commodity (10^3m^3)	2,064,111	684,811	492,165	156,797	270	136,184	451,570	12,117	130,196	0	0	0	0
22	Downstream Customer (customers)	3,214,599	3,118,230	94,509	1,164	12	96	12	24	552	0	0	0	0
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)	256.004	0.000	0.000	166.476	266.274	295.989	0.000	0.000	78.737	0.000	0.000	0.000	0.000
28	Upstream Commodity ($/$10^3m^3$)	254.123	34.709	33.840	15.704	7.334	7.728	0.000	0.000	11.459	303.000	158.433	263.120	375.518
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)	207.636	0.000	0.000	151.236	130.439	158.465	103.490	28.704	77.695	0.000	0.000	0.000	0.000
32	Downstream Commodity ($/$10^3m^3$)	2.797	27.385	25.957	9.695	0.000	3.095	0.358	26.204	7.216	0.000	0.000	0.000	0.000
33	Downstream Customer ($/customer)	32.036	27.916	142.040	1,121.368	274.949	2,363.235	9,990.436	11,635.540	1,045.472	0.000	0.000	0.000	0.000

Centra Gas Manitoba Inc.
2010/11 Test Year
Comparison of Gas Costs vs. Non-Gas Costs
Rates Reflecting Order 128/09

Schedule 9.2.2

	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 FPO
1	REVENUE REQUIREMENTS													
2	Upstream Demand ($)													
3	Gas Costs	32,766,731	16,928,732	11,774,331	2,627,830	6,502	543,510	0	0	885,825	0	0	0	0
4	Non-gas Costs	1,264,512	653,302	454,387	101,411	251	20,975	0	0	34,185	0	0	0	0
5	Total	34,031,243	17,582,035	12,228,718	2,729,242	6,753	564,485	0	0	920,010	0	0	0	0
6		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Upstream Commodity ($)													
8	Gas Costs	357,149,029	2,989,289	2,128,563	475,377	734	100,593	0	0	370,043	333,046,453	4,221,998	7,978,629	5,837,350
9	Non-gas Costs	8,958,250	3,198,064	2,297,759	601,316	1,246	150,225	0	0	471,998	1,722,210	21,102	39,877	454,452
10	Total	366,107,279	6,187,353	4,426,322	1,076,693	1,980	250,818	0	0	842,041	334,768,662	4,243,099	8,018,507	6,291,802
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	389,915,760	19,918,021	13,902,894	3,103,207	7,236	644,103	0	0	1,255,868	333,046,453	4,221,998	7,978,629	5,837,350
19	Total Non-gas Costs	10,222,762	3,851,366	2,752,147	702,727	1,497	171,200	0	0	506,183	1,722,210	21,102	39,877	454,452
20	Total Upstream Costs	400,138,522	23,769,388	16,655,041	3,805,935	8,733	815,303	0	0	1,762,051	334,768,662	4,243,099	8,018,507	6,291,802
21		0	0	0	0	0	0	0	0	0	0	0	0	0
22	Downstream Demand ($)													
23	Gas Costs	198,444	77,467	53,945	14,300	30	10,074	29,768	7,322	5,539	0	0	0	0
24	Non-gas Costs	34,457,887	16,459,337	11,133,429	2,877,651	3,278	1,115,362	1,484,571	305,551	1,078,708	0	0	0	0
25	Total	34,656,331	16,536,803	11,187,374	2,891,951	3,308	1,125,436	1,514,339	312,873	1,084,247	0	0	0	0
26														
27	Downstream Commodity ($)													
28	Gas Costs	5,753,947	2,209,516	1,582,335	506,347	0	420,038	161,111	316,467	558,133	0	0	0	0
29	Non-gas Costs	18,997	7,295	5,224	1,672	0	1,387	532	1,045	1,843	0	0	0	0
30	Total	5,772,944	2,216,810	1,587,560	508,019	0	421,425	161,642	317,512	559,976	0	0	0	0
31														
32	Downstream Customer ($)													
33	Gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Non-gas Costs	102,982,956	87,047,239	13,424,037	1,305,272	3,299	226,871	119,885	279,253	577,100	0	0	0	0
35	Total	102,982,956	87,047,239	13,424,037	1,305,272	3,299	226,871	119,885	279,253	577,100	0	0	0	0
36														
37	Downstream Total ($)													
38	Total Gas Costs	5,952,391	2,286,982	1,636,280	520,647	30	430,112	190,878	323,789	563,672	0	0	0	0
39	Total Non-gas Costs	137,459,840	103,513,871	24,562,690	4,184,595	6,578	1,343,619	1,604,988	585,849	1,657,651	0	0	0	0
40	Total Downstream Costs	143,412,231	105,800,853	26,198,970	4,705,242	6,608	1,773,731	1,795,866	909,638	2,221,323	0	0	0	0
41														
42	Grand Total Gas Costs	395,868,151	22,205,004	15,539,174	3,623,854	7,266	1,074,216	190,878	323,789	1,819,540	333,046,453	4,221,998	7,978,629	5,837,350
43	Grand Total Non-gas Costs	147,682,602	107,365,237	27,314,837	4,887,323	8,075	1,514,819	1,604,988	585,849	2,163,834	1,722,210	21,102	39,877	454,452
44	Grand Total	543,550,753	129,570,240	42,854,011	8,511,177	15,341	2,589,035	1,795,866	909,638	3,983,374	334,768,662	4,243,099	8,018,507	6,291,802
45														
46														

47 Calculation of the Primary Gas Overhead Rate: 1,722,210 (line 9, PG column)
48 1,104,846 (10^3m^3 (Schedule 9.2.1, line 17, PG column)
49 1.56 10^3m^3

Calculation of the Fixed Rate Primary Gas P 454,452 (line 9, FPO column)
16,755 (10^3m^3 (Schedule 9.2.1, line 17, FPO column)
27.12 per 10^3m^3

Centra Gas Manitoba Inc.
2010/11 Test Year
Total Functionalization By Customer Class
Rates Reflecting Order 128/09

Schedule 9.2.3

		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	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Energy	353,322,071	0	0	0	0	0	0	0	0	0	0	334,768,662	4,243,099	8,018,507	6,291,802
4	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Total	353,322,071	0	0	0	0	0	0	0	0	0	0	334,768,662	4,243,099	8,018,507	6,291,802
6																
7	PIPELINE															
8	Demand	15,537,438	6,899,142	1,128,180	8,027,323	5,583,191	1,246,073	3,083	257,724	0	0	420,043	0	0	0	0
9	Energy	1,007,509	415,665	63,247	478,912	344,187	90,484	189	22,697	0	0	71,040	0	0	0	0
10	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Total	16,544,947	7,314,807	1,191,428	8,506,235	5,927,379	1,336,557	3,272	280,420	0	0	491,084	0	0	0	0
12																
13	STORAGE															
14	Demand	18,493,806	8,211,869	1,342,844	9,554,712	6,645,527	1,483,168	3,670	306,762	0	0	499,967	0	0	0	0
15	Energy	11,777,699	4,937,411	771,030	5,708,441	4,082,135	986,209	1,791	228,121	0	0	771,001	0	0	0	0
16	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Total	30,271,504	13,149,279	2,113,874	15,263,153	10,727,662	2,469,378	5,461	534,883	0	0	1,270,967	0	0	0	0
18																
19	TRANSMISSION															
20	Demand	11,839,145	4,335,316	771,080	5,106,396	3,235,211	796,923	1,632	564,990	1,514,339	312,873	306,782	0	0	0	0
21	Energy	5,772,944	1,924,048	292,762	2,216,810	1,587,560	508,019	0	421,425	161,642	317,512	559,976	0	0	0	0
22	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Total	17,612,089	6,259,364	1,063,843	7,323,207	4,822,770	1,304,942	1,632	986,415	1,675,981	630,385	866,757	0	0	0	0
24																
25	DISTRIBUTION															
26	Demand	22,817,186	9,824,698	1,605,710	11,430,407	7,952,163	2,095,028	1,676	560,446	0	0	777,465	0	0	0	0
27	Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Customer	9,345,465	8,460,779	604,905	9,065,684	274,768	3,384	2	18	0	4	1,605	0	0	0	0
29	Total	32,162,651	18,285,476	2,210,615	20,496,091	8,226,931	2,098,412	1,679	560,464	0	4	779,070	0	0	0	0
30																
31	ONSITE															
32	Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Customer	93,637,491	69,811,875	8,169,680	77,981,555	13,149,269	1,301,888	3,297	226,853	119,885	279,248	575,495	0	0	0	0
35	Total	93,637,491	69,811,875	8,169,680	77,981,555	13,149,269	1,301,888	3,297	226,853	119,885	279,248	575,495	0	0	0	0
36																
37	TOTAL SERVICE															
38	Demand	68,687,574	29,271,024	4,847,814	34,118,838	23,416,092	5,621,193	10,061	1,689,921	1,514,339	312,873	2,004,257	0	0	0	0
39	Energy	371,880,223	7,277,123	1,127,040	8,404,163	6,013,882	1,584,712	1,980	672,243	161,642	317,512	1,402,016	334,768,662	4,243,099	8,018,507	6,291,802
40	Customer	102,982,956	78,272,654	8,774,585	87,047,239	13,424,037	1,305,272	3,299	226,871	119,885	279,253	577,100	0	0	0	0
41	Total	543,550,753	114,820,802	14,749,439	129,570,240	42,854,011	8,511,177	15,341	2,589,035	1,795,866	909,638	3,983,374	334,768,662	4,243,099	8,018,507	6,291,802

Centra Gas Manitoba Inc.
2010/11 Test Year
Allocation Results of Rate Base
Rates Reflecting Order 128/09

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	37,735		0	37,735		22,527	3,166	25,693	8,115	1,492
Other Intangible Plant	402	0		0	0		0	0	0	0	0
Sub-total	401-402	37,735		0	37,735		22,527	3,166	25,693	8,115	1,492
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	1,232,659		0	1,232,659		413,712	67,481	481,193	335,083	88,823
Land Rights	461	2,970,404		0	2,970,404		996,945	162,613	1,159,558	807,468	214,042
Structures & Improvments	463	1,002,537		0	1,002,537		336,477	54,883	391,361	272,527	72,241
Mains	465	92,081,965		0	92,081,965		30,905,099	5,040,962	35,946,061	25,031,353	6,635,272
Measuring & Reg. Equipment	467	7,082,830		0	7,082,830		2,377,182	387,745	2,764,926	1,925,380	510,377
Other Transmission Equipment	469	5,150		0	5,150		1,729	282	2,010	1,400	371
Sub-total	460-469	104,375,545		0	104,375,545		35,031,144	5,713,965	40,745,109	28,373,212	7,521,127
E. DISTRIBUTION PLANT											
Land	470	819,308		0	819,308		533,496	73,690	607,186	166,552	26,883
Land Rights	471	651,504		0	651,504		424,230	58,597	482,827	132,440	21,377
Structures & Improvements	472	1,342,407		0	1,342,407		592,816	96,913	689,729	479,786	126,298
Structures & Improvements: M & R	472.1	4,089,032		0	4,089,032		1,692,243	276,455	1,968,698	1,369,907	361,387
Services	473	207,117,471		0	207,117,471		165,254,164	22,535,596	187,789,761	18,223,849	656,294
Regulators	474	46,752,083		0	46,752,083		25,112,557	4,483,636	29,596,194	15,569,819	977,970
Regulators & Meters Installations	474.1	0		0	0		0	0	0	0	0
Mains	475	162,291,074		0	162,291,074		96,755,311	11,312,470	108,067,782	40,259,879	10,198,816
Measuring & Reg. Equipment	477	35,383,327		0	35,383,327		13,768,615	2,249,323	16,017,938	11,145,986	2,940,359
Telemetry Equipment	477.1	4,046,235		0	4,046,235		1,674,531	273,561	1,948,093	1,355,569	357,605
Meters	478	41,092,142		0	41,092,142		22,072,359	3,940,835	26,013,194	13,684,892	859,574
AMR/ERT Modules	479	89,085		0	89,085		89,085	0	89,085	0	0
Other Distribution Equipment	-	0		0	0		0	0	0	0	0
Sub-total	470-479	503,673,669		0	503,673,669		327,969,409	45,301,077	373,270,486	102,388,679	16,526,562
F. GENERAL PLANT											
Land	480	137,935		0	137,935		96,214	9,095	105,308	20,964	4,129
Structures & Improvements	482	9,212,364		0	9,212,364		6,425,884	607,423	7,033,308	1,400,160	275,768
Leasehold Improvements	482.1	1,036,790		0	1,036,790		723,190	68,361	791,552	157,579	31,036
Office Furniture & Equipment	483	988,280		0	988,280		689,353	65,163	754,516	150,206	29,584
Computer Equipment: Hardware	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	9,701,325		0	9,701,325		6,766,948	639,663	7,406,612	1,474,476	290,404
Transportation Equipment	484	1,239,187		0	1,239,187		864,368	81,707	946,075	188,340	37,094
Vehicle Conversion Kits	484.1	0		0	0		0	0	0	0	0
Heavy Work Equipment	485	678,212		0	678,212		396,279	55,648	451,927	148,943	28,573
Tools & Work Equipment	486	2,928,013		0	2,928,013		1,710,834	240,247	1,951,081	643,024	123,356
Rental Equipment: Conv. Bur.	487	0		0	0		0	0	0	0	0
Communication Equipment	488	43,106		0	43,106		30,068	2,842	32,910	6,552	1,290
Other General Equipment	489	0		0	0		0	0	0	0	0
Sub-total	480-490	25,965,213		0	25,965,213		17,703,138	1,770,151	19,473,288	4,190,244	821,233
Sub-total Plant-in-Service		634,052,162		0	634,052,162		380,726,218	52,788,359	433,514,577	134,960,249	24,870,414
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		**634,052,162**		**0**	**634,052,162**		**380,726,218**	**52,788,359**	**433,514,577**	**134,960,249**	**24,870,414**
II. ACCUMULATED DEPRECIATION											
Intangible Plant		-22,482		0	-22,482		-13,402	-1,885	-15,287	-4,812	-893
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.
2010/11 Test Year
Allocation Results of Rate Base
Rates Reflecting Order 128/09

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	37,735	2	506	991	350	585	0	0	0	0
Other Intangible Plant	402	0	0	0	0	0	0	0	0	0	0
Sub-total	401-402	37,735	2	506	991	350	585	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	1,232,659	185	62,578	184,907	45,482	34,407	0	0	0	0
Land Rights	461	2,970,404	446	150,797	445,580	109,602	82,912	0	0	0	0
Structures & Improvments	463	1,002,537	150	50,895	150,387	36,991	27,984	0	0	0	0
Mains	465	92,081,965	13,820	4,674,678	13,812,888	3,397,627	2,570,266	0	0	0	0
Measuring & Reg. Equipment	467	7,082,830	1,063	359,570	1,062,470	261,341	197,702	0	0	0	0
Other Transmission Equipment	469	5,150	1	261	773	190	144	0	0	0	0
Sub-total	460-469	104,375,545	15,665	5,298,780	15,657,004	3,851,234	2,913,414	0	0	0	0
E. DISTRIBUTION PLANT											
Land	470	819,308	30	4,633	511	2,919	10,593	0	0	0	0
Land Rights	471	651,504	24	3,684	406	2,321	8,423	0	0	0	0
Structures & Improvements	472	1,342,407	0	0	0	0	46,594	0	0	0	0
Structures & Improvements: M & R	472.1	4,089,032	756	252,900	0	0	135,385	0	0	0	0
Services	473	207,117,471	0	77,958	0	0	369,610	0	0	0	0
Regulators	474	46,752,083	0	107,084	0	0	501,016	0	0	0	0
Regulators & Meters Installations	474.1	0	0	0	0	0	0	0	0	0	0
Mains	475	162,291,074	0	0	0	0	3,764,598	0	0	0	0
Measuring & Reg. Equipment	477	35,383,327	17,155	2,057,671	313,332	1,789,355	1,101,532	0	0	0	0
Telemetry Equipment	477.1	4,046,235	749	250,253	0	0	133,968	0	0	0	0
Meters	478	41,092,142	0	94,120	0	0	440,361	0	0	0	0
AMR/ERT Modules	479	89,085	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	503,673,669	18,714	2,848,304	314,250	1,794,596	6,512,079	0	0	0	0
F. GENERAL PLANT											
Land	480	137,935	8	1,289	1,487	467	1,710	1,839	22	41	671
Structures & Improvements	482	9,212,364	510	86,118	99,294	31,159	114,216	122,823	1,458	2,756	44,795
Leasehold Improvements	482.1	1,036,790	57	9,692	11,175	3,507	12,854	13,823	164	310	5,041
Office Furniture & Equipment	483	988,280	55	9,239	10,652	3,343	12,253	13,176	156	296	4,806
Computer Equipment: Hardware	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	9,701,325	537	90,689	104,564	32,813	120,278	129,342	1,536	2,902	47,173
Transportation Equipment	484	1,239,187	69	11,584	13,356	4,191	15,364	16,521	196	371	6,026
Vehicle Conversion Kits	484.1	0	0	0	0	0	0	0	0	0	0
Heavy Work Equipment	485	678,212	40	10,135	20,621	6,826	11,148	0	0	0	0
Tools & Work Equipment	486	2,928,013	175	43,754	89,024	29,470	48,129	0	0	0	0
Rental Equipment: Conv. Bur.	487	0	0	0	0	0	0	0	0	0	0
Communication Equipment	488	43,106	2	403	465	146	534	575	7	13	210
Other General Equipment	489	0	0	0	0	0	0	0	0	0	0
Sub-total	480-490	25,965,213	1,453	262,904	350,638	111,920	336,486	298,098	3,539	6,688	108,721
Sub-total Plant-in-Service		634,052,162	35,834	8,410,494	16,322,883	5,758,100	9,762,564	298,098	3,539	6,688	108,721
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		**634,052,162**	**35,834**	**8,410,494**	**16,322,883**	**5,758,100**	**9,762,564**	**298,098**	**3,539**	**6,688**	**108,721**
II. ACCUMULATED DEPRECIATION											
Intangible Plant		-22,482	-1	-325	-593	-220	-350	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.
2010/11 Test Year
Allocation Results of Rate Base
Rates Reflecting Order 128/09

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		-26,418,532		0	-26,418,532		-8,866,743	-1,446,259	-10,313,001	-7,181,558	-1,903,695
Distribution Plant		-185,658,131		0	-185,658,131		-120,863,470	-16,725,568	-137,589,038	-37,401,711	-6,071,604
General Plant		-17,708,350		0	-17,708,350		-11,926,696	-1,216,791	-13,143,486	-2,969,566	-588,989
Retirement Work in Progress		0		0	0		0	0	0	0	0
Sub-total		-229,807,496		0	-229,807,496		-141,670,310	-19,390,503	-161,060,813	-47,557,647	-8,565,182
Plant Held For Future Use		0		0	0		0	0	0	0	0
Total Accumulated Depreciation		**-229,807,496**		**0**	**-229,807,496**		**-141,670,310**	**-19,390,503**	**-161,060,813**	**-47,557,647**	**-8,565,182**
III. OTHER RATE BASE											
Contributions in Aid of Construction		-50,956,494		0	-50,956,494		-19,273,546	-3,099,097	-22,372,642	-14,068,091	-3,599,740
Cash Working Capital		20,194,413		0	20,194,413		6,640,271	777,939	7,418,210	1,936,253	354,672
Security Deposits		-500,000		0	-500,000		-401,313	-28,692	-430,005	-57,350	-7,913
Gas in Storage		75,807,923		0	75,807,923		31,275,820	4,758,916	36,034,735	25,897,672	6,808,266
Investment in DSM		37,058,080		0	37,058,080		22,234,848	6,299,874	28,534,721	7,782,197	370,581
Total Other Rate Base		**81,603,922**		**0**	**81,603,922**		**40,476,079**	**8,708,940**	**49,185,019**	**21,490,680**	**3,925,865**
TOTAL RATE BASE		**485,848,588**		**0**	**485,848,588**		**279,531,987**	**42,106,796**	**321,638,783**	**108,893,283**	**20,231,098**

Centra Gas Manitoba Inc.
2010/11 Test Year
Allocation Results of Rate Base
Rates Reflecting Order 128/09

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		-26,418,532	-3,965	-1,341,204	-3,962,799	-974,810	-737,501	0	0	0	0
Distribution Plant		-185,658,131	-8,334	-1,274,219	-137,362	-784,441	-2,391,422	0	0	0	0
General Plant		-17,708,350	-936	-162,607	-247,028	-78,942	-239,726	-198,045	-2,351	-4,443	-72,230
Retirement Work in Progress		0	0	0	0	0	0	0	0	0	0
Sub-total		-229,807,496	-13,236	-2,778,355	-4,347,782	-1,838,413	-3,368,998	-198,045	-2,351	-4,443	-72,230
Plant Held For Future Use		0	0	0	0	0	0	0	0	0	0
Total Accumulated Depreciation		**-229,807,496**	**-13,236**	**-2,778,355**	**-4,347,782**	**-1,838,413**	**-3,368,998**	**-198,045**	**-2,351**	**-4,443**	**-72,230**
III. OTHER RATE BASE											
Contributions in Aid of Construction		-50,956,494	-6,447	-2,136,779	-5,911,318	-1,475,197	-1,386,279	0	0	0	0
Cash Working Capital		20,194,413	644	113,664	78,689	34,990	150,286	9,551,347	121,022	228,704	205,933
Security Deposits		-500,000	-82	-653	-82	-163	-3,753	0	0	0	0
Gas in Storage		75,807,923	14,207	1,707,774	0	0	5,345,268	0	0	0	0
Investment in DSM		37,058,080	0	370,581	0	0	0	0	0	0	0
Total Other Rate Base		**81,603,922**	**8,322**	**54,587**	**-5,832,711**	**-1,440,370**	**4,105,523**	**9,551,347**	**121,022**	**228,704**	**205,933**
TOTAL RATE BASE		**485,848,588**	**30,921**	**5,686,726**	**6,142,390**	**2,479,317**	**10,499,088**	**9,651,400**	**122,210**	**230,949**	**242,424**

Centra Gas Manitoba Inc.
2010/11 Test Year
Allocation Results of Cost of Service Elements
Rates Reflecting Order 128/09

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											
TCPL FS Demand - Sask Zone		220,729		0	220,729		98,011	16,027	114,038	79,316	17,702
TCPL STS Demand		1,591,290		0	1,591,290		706,586	115,544	822,130	571,811	127,618
TCPL FS Demand - SSDA (Welwyn)		9,859,237		0	9,859,237		4,377,831	715,884	5,093,715	3,542,798	790,692
TCPL FS Demand - SSDA (Welwyn) to Man Zone		7,865,053		0	7,865,053		3,492,347	571,085	4,063,432	2,826,212	630,762
TCPL FS Demand - Man Zone		1,738,049		0	1,738,049		771,752	126,201	897,952	624,547	139,388
Storage Capacity Charge		6,065,784		0	6,065,784		2,693,411	440,439	3,133,850	2,179,666	486,464
Storage Deliverability Charge		4,805,100		0	4,805,100		2,133,625	348,901	2,482,526	1,726,655	385,360
ANR Oklahoma Demand		522,334		0	522,334		231,934	37,927	269,861	187,695	41,890
ANR Louisiana Demand		1,523,565		0	1,523,565		676,514	110,627	787,140	547,475	122,187
ANR Crystal Falls to Storage Demand		1,777,913		0	1,777,913		789,453	129,095	918,548	638,872	142,585
GLGT Emerson to Crystal Falls Demand		2,160,818		0	2,160,818		959,475	156,898	1,116,373	776,464	173,294
GLGT Backhaul Demand		1,054,553		0	1,054,553		468,257	76,572	544,828	378,941	84,573
Forecast Capacity Management Revenues		-6,800,000		0	-6,800,000		-3,019,428	-493,751	-3,513,179	-2,443,498	-545,347
Sub-total		32,384,424		0	32,384,424		14,379,768	2,351,448	16,731,215	11,636,953	2,597,170
B. VARIABLE TRANSPORTATION											
TCPL FS - Sask Zone		7,690		0	7,690		3,173	483	3,655	2,627	691
TCPL FS - Flowing directly to Man Zone		41,200		0	41,200		16,998	2,586	19,584	14,075	3,700
TCPL FS - SSDA (Welwyn)		566,137		0	566,137		233,569	35,540	269,109	193,405	50,844
TCPL FS - SSDA (Welwyn) to Man Zone		348,338		0	348,338		143,713	21,867	165,580	119,000	31,284
ANR Oklahoma to Crystall Falls		20,769		0	20,769		8,877	1,429	10,306	7,326	1,583
ANR Storage Transportation		80,548		0	80,548		34,429	5,541	39,970	28,413	6,140
Storage Withdrawl Chg.		125,410		0	125,410		53,605	8,627	62,232	44,238	9,560
Storage Gas - Transportation & Delivery Cost		4,265,858		0	4,265,858		1,823,382	293,444	2,116,826	1,504,778	325,179
Compressor Fuel: TCPL SSDA		16,130		0	16,130		0	0	0	0	0
Compressor Fuel: TCPL MDA		267,265		0	267,265		0	0	0	0	0
Compressor Fuel: TCPL to SSDA (Welwyn)		943,271		0	943,271		0	0	0	0	0
Compressor Fuel: TCPL SSDA (Welwyn) to MDA		444,216		0	444,216		0	0	0	0	0
Compressor Fuel: Oklahoma		149,278		0	149,278		63,807	10,269	74,075	52,658	11,379
Compressor Fuel: Storage		459,370		0	459,370		196,351	31,600	227,951	162,043	35,017
Sub-total		7,735,482		0	7,735,482		2,577,904	411,385	2,989,289	2,128,563	475,377
C. COMMODITY COST											
Primary Direct to System		265,213,668		0	265,213,668		1,440,162	219,134	1,659,296	1,188,298	380,255
Storage Gas: Primary to System		71,650,375		0	71,650,375		389,076	59,202	448,277	321,032	102,730
Oklahoma Supply		4,140,315		0	4,140,315		18,830	2,865	21,695	15,537	4,972
Storage Gas: Supplemental Supply		0		0	0		0	0	0	0	0
Seasonal Delivered Service		8,216,051		0	8,216,051		37,367	5,686	43,052	30,832	9,866
Delivered Service		13,052		0	13,052		59	9	68	49	16
Fixed Price Offering		5,934,032		0	5,934,032		32,223	4,903	37,126	26,588	8,508
Sub-total		355,167,494		0	355,167,494		1,917,717	291,799	2,209,516	1,582,335	506,347
D. OTHER GAS COSTS											
Minell Charges		198,444		0	198,444		66,603	10,864	77,467	53,945	14,300
Load Balancing Charges		228,000		0	228,000		101,240	16,555	117,795	81,929	18,285
Baseload Volume Price Increment Charges		154,307		0	154,307		68,518	11,204	79,722	55,449	12,375
Sub-total		580,751		0	580,751		236,360	38,623	274,983	191,322	44,960
Total Cost of Gas		**395,868,151**		**0**	**395,868,151**		**19,111,748**	**3,093,255**	**22,205,004**	**15,539,174**	**3,623,854**
II. OTHER REVENUE											
Rental Income		-39,786		0	-39,786		-37,131	-2,655	-39,786	0	0
Late Payment Charge		-1,849,388		0	-1,849,388		-1,725,988	-123,400	-1,849,388	0	0
Broker Revenue		-136,616		0	-136,616		-101,855	-11,919	-113,774	-19,185	-1,899
Other		0		0	0		0	0	0	0	0
Total Other Revenue		**-2,025,790**		**0**	**-2,025,790**		**-1,864,974**	**-137,974**	**-2,002,948**	**-19,185**	**-1,899**

Centra Gas Manitoba Inc.
2010/11 Test Year
Allocation Results of Cost of Service Elements
Rates Reflecting Order 128/09

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		220,729	44	3,661	0	0	5,967	0	0	0	0
TCPL STS Demand		1,591,290	316	26,395	0	0	43,019	0	0	0	0
TCPL FS Demand - SSDA (Welwyn)		9,859,237	1,956	163,538	0	0	266,537	0	0	0	0
TCPL FS Demand - SSDA (Welwyn) to Man Zone		7,865,053	1,561	130,460	0	0	212,626	0	0	0	0
TCPL FS Demand - Man Zone		1,738,049	345	28,829	0	0	46,987	0	0	0	0
Storage Capacity Charge		6,065,784	1,204	100,615	0	0	163,984	0	0	0	0
Storage Deliverability Charge		4,805,100	954	79,703	0	0	129,902	0	0	0	0
ANR Oklahoma Demand		522,334	104	8,664	0	0	14,121	0	0	0	0
ANR Louisiana Demand		1,523,565	302	25,272	0	0	41,188	0	0	0	0
ANR Crystal Falls to Storage Demand		1,777,913	353	29,491	0	0	48,065	0	0	0	0
GLGT Emerson to Crystal Falls Demand		2,160,818	429	35,842	0	0	58,416	0	0	0	0
GLGT Backhaul Demand		1,054,553	209	17,492	0	0	28,509	0	0	0	0
Forecast Capacity Management Revenues		-6,800,000	-1,349	-112,793	0	0	-183,833	0	0	0	0
Sub-total		32,384,424	6,426	537,169	0	0	875,489	0	0	0	0
B. VARIABLE TRANSPORTATION											
TCPL FS - Sask Zone		7,690	1	173	0	0	542	0	0	0	0
TCPL FS - Flowing directly to Man Zone		41,200	8	928	0	0	2,905	0	0	0	0
TCPL FS - SSDA (Welwyn)		566,137	106	12,754	0	0	39,919	0	0	0	0
TCPL FS - SSDA (Welwyn) to Man Zone		348,338	65	7,847	0	0	24,562	0	0	0	0
ANR Oklahoma to Crystall Falls		20,769	2	321	0	0	1,230	0	0	0	0
ANR Storage Transportation		80,548	9	1,246	0	0	4,770	0	0	0	0
Storage Withdrawl Chg.		125,410	14	1,939	0	0	7,427	0	0	0	0
Storage Gas - Transportation & Delivery Cost		4,265,858	463	65,972	0	0	252,641	0	0	0	0
Compressor Fuel: TCPL SSDA		16,130	0	0	0	0	0	16,130	0	0	0
Compressor Fuel: TCPL MDA		267,265	0	0	0	0	0	267,265	0	0	0
Compressor Fuel: TCPL to SSDA (Welwyn)		943,271	0	0	0	0	0	943,271	0	0	0
Compressor Fuel: TCPL SSDA (Welwyn) to MDA		444,216	0	0	0	0	0	444,216	0	0	0
Compressor Fuel: Oklahoma		149,278	16	2,309	0	0	8,841	0	0	0	0
Compressor Fuel: Storage		459,370	50	7,104	0	0	27,206	0	0	0	0
Sub-total		7,735,482	734	100,593	0	0	370,043	1,670,883	0	0	0
C. COMMODITY COST											
Primary Direct to System		265,213,668	0	315,439	120,990	237,660	419,145	260,892,583	0	0	0
Storage Gas: Primary to System		71,650,375	0	85,219	32,687	64,206	113,237	70,482,987	0	0	0
Oklahoma Supply		4,140,315	0	4,124	1,582	3,107	5,480	0	1,410,374	2,673,443	0
Storage Gas: Supplemental Supply		0	0	0	0	0	0	0	0	0	0
Seasonal Delivered Service		8,216,051	0	8,184	3,139	6,166	10,875	0	2,798,749	5,305,187	0
Delivered Service		13,052	0	13	5	10	17	0	12,874	0	0
Fixed Price Offering		5,934,032	0	7,058	2,707	5,318	9,378	0	0	0	5,837,350
Sub-total		355,167,494	0	420,038	161,111	316,467	558,133	331,375,570	4,221,998	7,978,629	5,837,350
D. OTHER GAS COSTS											
Minell Charges		198,444	30	10,074	29,768	7,322	5,539	0	0	0	0
Load Balancing Charges		228,000	45	3,782	0	0	6,164	0	0	0	0
Baseload Volume Price Increment Charges		154,307	31	2,560	0	0	4,172	0	0	0	0
Sub-total		580,751	106	16,416	29,768	7,322	15,875	0	0	0	0
Total Cost of Gas		**395,868,151**	**7,266**	**1,074,216**	**190,878**	**323,789**	**1,819,540**	**333,046,453**	**4,221,998**	**7,978,629**	**5,837,350**
II. OTHER REVENUE											
Rental Income		-39,786	0	0	0	0	0	0	0	0	0
Late Payment Charge		-1,849,388	0	0	0	0	0	0	0	0	0
Broker Revenue		-136,616	-5	-331	-175	-407	-840	0	0	0	0
Other		0	0	0	0	0	0	0	0	0	0
Total Other Revenue		**-2,025,790**	**-5**	**-331**	**-175**	**-407**	**-840**	**0**	**0**	**0**	**0**

Centra Gas Manitoba Inc.
2010/11 Test Year
Allocation Results of Cost of Service Elements
Rates Reflecting Order 128/09

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		234,000		0	234,000		163,457	15,468	178,925	35,755	7,053
Insurance		62,000		0	62,000		43,309	4,098	47,407	9,473	1,869
Public Affairs		801,000		0	801,000		559,525	52,947	612,473	122,391	24,143
Sub-total		1,097,000		0	1,097,000		766,291	72,514	838,804	167,619	33,065
B. FINANCE & ADMINISTRATION											
Customer Billing		3,560,000		6,000	3,554,000		3,217,570	230,041	3,447,611	104,492	1,287
Banner System		1,108,000		0	1,108,000		1,003,114	71,718	1,074,832	32,577	401
Gas IT		325,000		0	325,000		226,697	21,429	248,126	49,396	9,729
Gas Accounting		405,000		8,000	397,000		19,166	3,102	22,268	15,584	3,634
Gas Regulatory		2,761,000		33,000	2,728,000		1,902,857	179,873	2,082,730	414,621	81,661
Gas Supply		2,985,473		93,416	2,892,057		935,636	152,506	1,088,142	758,704	181,971
Treasury		336,000		0	336,000		234,369	22,154	256,524	51,068	10,058
Sub-total		11,480,473		140,416	11,340,057		7,539,410	680,822	8,220,232	1,426,440	288,741
C. TRANSMISSION & DISTRIBUTION											
Property Taxes		67,000		0	67,000		39,998	5,621	45,620	14,408	2,650
Research & Development		60,000		0	60,000		33,837	4,213	38,051	16,252	4,161
Station Maintenance		4,967,000		580,210	4,386,790		2,699,656	332,035	3,031,692	1,263,534	323,636
System Integrity		1,665,000		0	1,665,000		835,602	107,041	942,643	427,364	110,188
System Maintenance & Support		616,000		0	616,000		309,148	39,602	348,750	158,112	40,766
System Support & Communication Systems		258,000		0	258,000		43,894	7,169	51,063	35,537	102,012
Sub-total		7,633,000		580,210	7,052,790		3,962,136	495,682	4,457,818	1,915,207	583,413
D. POWER SUPPLY											
Health, Safety, Environment		232,000		0	232,000		116,432	14,915	131,347	59,549	15,353
Sub-total		232,000		0	232,000		116,432	14,915	131,347	59,549	15,353
E. CUSTOMER SERVICE & MARKETING											
Billing Inquiries & Collections		11,071,000		2,978,947	8,092,053		8,992,153	758,149	9,750,302	1,075,056	128,067
Customer Inspections		10,799,000		2,908,865	7,890,135		9,532,309	699,361	10,231,671	367,196	44,403
Customer Relations		6,420,000		165,000	6,255,000		3,426,958	352,534	3,779,492	1,490,398	527,176
Customer Safety		2,660,000		0	2,660,000		1,699,477	121,504	1,820,981	822,999	10,026
Work Coordination		2,914,000		0	2,914,000		2,416,873	210,864	2,627,737	277,301	5,208
Distribution Maintenance		8,744,000		0	8,744,000		5,265,737	764,951	6,030,688	1,834,852	348,015
Emergency		107,000		0	107,000		85,881	6,140	92,021	12,273	1,693
Load Forecast		225,000		13,000	212,000		115,220	8,238	123,458	4,289	53,068
Meter Reading		1,873,000		0	1,873,000		1,423,338	179,900	1,603,237	254,127	9,454
Metering		4,696,000		0	4,696,000		3,450,912	246,724	3,697,636	924,413	46,280
Sub-total		49,509,000		6,065,812	43,443,188		36,408,859	3,348,364	39,757,223	7,062,902	1,173,390
F. ADJUSTMENTS TO INCOME											
Corporate Alloc. & Adj.		-713,000		0	-713,000		-497,338	-47,012	-544,350	-108,367	-21,343
Depreciation, Interest, Taxes		-8,895,000		0	-8,895,000		-6,204,514	-586,498	-6,791,012	-1,351,925	-266,267
Sub-total		-9,608,000		0	-9,608,000		-6,701,851	-633,510	-7,335,361	-1,460,291	-287,611
Total Operating & Maintenance Expenses		**60,343,473**		**6,786,439**	**53,557,034**		**42,091,276**	**3,978,788**	**46,070,064**	**9,171,425**	**1,806,352**

Centra Gas Manitoba Inc.
2010/11 Test Year
Allocation Results of Cost of Service Elements
Rates Reflecting Order 128/09

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											
Audit		234,000	11	1,663	2,522	791	2,915	3,120	37	70	1,138
Insurance		62,000	3	441	668	210	772	827	10	19	301
Public Affairs		801,000	39	5,694	8,633	2,709	9,977	10,679	127	240	3,895
Sub-total		1,097,000	53	7,798	11,824	3,710	13,664	14,626	174	328	5,334
B. FINANCE & ADMINISTRATION											
Customer Billing		3,560,000	0	0	0	0	610	0	0	0	6,000
Banner System		1,108,000	0	0	0	0	190	0	0	0	0
Gas IT		325,000	18	3,038	3,503	1,099	4,029	4,333	51	97	1,580
Gas Accounting		405,000	7	1,077	191	325	1,825	333,999	4,234	8,001	13,854
Gas Regulatory		2,761,000	151	25,502	29,403	9,227	33,822	36,371	432	816	46,265
Gas Supply		2,985,473	407	77,004	164,196	40,388	71,670	538,811	6,128	11,580	46,473
Treasury		336,000	19	3,141	3,622	1,136	4,166	4,480	53	101	1,634
Sub-total		11,480,473	601	109,762	200,915	52,175	116,313	917,993	10,898	20,596	115,806
C. TRANSMISSION & DISTRIBUTION											
Property Taxes		67,000	4	898	1,760	622	1,039	0	0	0	0
Research & Development		60,000	0	0	0	0	1,536	0	0	0	0
Station Maintenance		4,967,000	679	226,167	0	4	121,289	0	0	0	0
System Integrity		1,665,000	90	30,598	90,412	22,239	41,465	0	0	0	0
System Maintenance & Support		616,000	33	11,320	33,450	8,228	15,341	0	0	0	0
System Support & Communication Systems		258,000	20	14,215	4,825	2,862	47,466	0	0	0	0
Sub-total		7,633,000	826	283,198	130,447	33,955	228,135	0	0	0	0
D. POWER SUPPLY											
Health, Safety, Environment		232,000	13	4,264	12,598	3,099	5,778	0	0	0	0
Sub-total		232,000	13	4,264	12,598	3,099	5,778	0	0	0	0
E. CUSTOMER SERVICE & MARKETING											
Billing Inquiries & Collections		11,071,000	1,320	10,562	1,320	2,641	60,733	0	0	0	41,000
Customer Inspections		10,799,000	110	29,648	87,088	21,461	17,424	0	0	0	0
Customer Relations		6,420,000	0	80,485	76,541	59,962	240,944	0	0	0	165,000
Customer Safety		2,660,000	103	827	103	207	4,754	0	0	0	0
Work Coordination		2,914,000	0	61	0	0	3,692	0	0	0	0
Distribution Maintenance		8,744,000	350	117,996	231,961	57,057	123,081	0	0	0	0
Emergency		107,000	17	140	17	35	803	0	0	0	0
Load Forecast		225,000	0	4,377	547	1,094	25,166	0	0	0	13,000
Meter Reading		1,873,000	0	982	123	245	4,832	0	0	0	0
Metering		4,696,000	477	3,817	477	954	21,947	0	0	0	0
Sub-total		49,509,000	2,378	248,894	398,179	143,656	503,377	0	0	0	219,000
F. ADJUSTMENTS TO INCOME											
Corporate Alloc. & Adj.		-713,000	-39	-6,665	-7,685	-2,412	-8,840	-9,506	-113	-213	-3,467
Depreciation, Interest, Taxes		-8,895,000	-492	-83,152	-95,874	-30,085	-110,281	-118,591	-1,408	-2,661	-43,252
Sub-total		-9,608,000	-532	-89,817	-103,559	-32,497	-119,121	-128,097	-1,521	-2,874	-46,719
Total Operating & Maintenance Expenses		**60,343,473**	**3,340**	**564,099**	**650,404**	**204,099**	**748,146**	**804,522**	**9,551**	**18,050**	**293,421**

Centra Gas Manitoba Inc.
2010/11 Test Year
Allocation Results of Cost of Service Elements
Rates Reflecting Order 128/09

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
IV. DEPRECIATION & AMORTIZATION											
Depreciation Expense		18,144,318		0	18,144,318		11,369,829	1,571,142	12,940,971	3,647,998	603,193
Amortization of Cust. Contributions		-996,299		0	-996,299		-58,690	64,220	5,530	-229,517	-120,456
Depreciation: Common Assets		4,251,000		0	4,251,000		2,965,193	280,293	3,245,485	646,097	127,252
Amortization Expense (Deferreds)		1,050,416		108,000	942,416		562,615	79,068	641,683	202,668	37,272
Demand Side Management Amortization Expense (Deferred)		4,918,053		0	4,918,053		2,950,832	836,069	3,786,901	1,032,791	49,181
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		**31,167,487**		**108,000**	**31,059,487**		**21,589,778**	**2,830,792**	**24,420,570**	**5,300,038**	**696,440**
V. CAPITAL & OTHER TAXES											
Municipal Taxes		15,664,700		0	15,664,700		9,351,702	1,314,261	10,665,962	3,368,717	619,522
Payroll Tax		780,780		0	780,780		544,616	51,481	596,097	118,668	23,372
Taxes on Common Assets		218,000		0	218,000		124,692	18,903	143,595	49,364	9,222
Corporate Capital Tax		2,768,746		0	2,768,746		1,583,666	240,083	1,823,750	626,952	117,123
Business Taxes		0		0	0		0	0	0	0	0
Other		0		0	0		0	0	0	0	0
Income Taxes		4,507,827		0	4,507,827		2,578,385	390,882	2,969,267	1,020,748	190,689
Total Taxes		**23,940,053**		**0**	**23,940,053**		**14,183,060**	**2,015,611**	**16,198,671**	**5,184,449**	**959,927**
VI. FINANCE EXPENSE		**19,257,379**		**0**	**19,257,379**		**11,079,693**	**1,668,970**	**12,748,663**	**4,316,158**	**801,892**
VII. CORPORATE ALLOCATION		**12,000,000**		**0**	**12,000,000**		**6,904,175**	**1,039,998**	**7,944,173**	**2,689,561**	**499,689**
VIII. NET INCOME (LOSS)		**3,000,000**		**0**	**3,000,000**		**1,726,044**	**259,999**	**1,986,043**	**672,390**	**124,922**
COST OF SERVICE SUMMARY											
COST OF GAS		395,868,151		0	395,868,151		19,111,748	3,093,255	22,205,004	15,539,174	3,623,854
OTHER REVENUE		-2,025,790		0	-2,025,790		-1,864,974	-137,974	-2,002,948	-19,185	-1,899
OPERATING EXPENSES											
President & CEO		1,097,000		0	1,097,000		766,291	72,514	838,804	167,619	33,065
Finance & Administration		11,480,473		140,416	11,340,057		7,539,410	680,822	8,220,232	1,426,440	288,741
Transmission & Distribution		7,633,000		580,210	7,052,790		3,962,136	495,682	4,457,818	1,915,207	583,413
Power Supply		232,000		0	232,000		116,432	14,915	131,347	59,549	15,353
Customer Service & Marketing		49,509,000		6,065,812	43,443,188		36,408,859	3,348,364	39,757,223	7,062,902	1,173,390
Adjustments to Income		-9,608,000		0	-9,608,000		-6,701,851	-633,510	-7,335,361	-1,460,291	-287,611
Sub-total		60,343,473		6,786,439	53,557,034		42,091,276	3,978,788	46,070,064	9,171,425	1,806,352
DEPRECIATION & AMORTIZATION		31,167,487		108,000	31,059,487		21,589,778	2,830,792	24,420,570	5,300,038	696,440
CAPITAL & OTHER TAXES		23,940,053		0	23,940,053		14,183,060	2,015,611	16,198,671	5,184,449	959,927
FINANCE EXPENSE		19,257,379		0	19,257,379		11,079,693	1,668,970	12,748,663	4,316,158	801,892
CORPORATE ALLOCATION		12,000,000		0	12,000,000		6,904,175	1,039,998	7,944,173	2,689,561	499,689
NET INCOME		3,000,000		0	3,000,000		1,726,044	259,999	1,986,043	672,390	124,922
COST OF SERVICE		543,550,753		6,894,439	536,656,314		114,820,802	14,749,439	129,570,240	42,854,011	8,511,177

Centra Gas Manitoba Inc.
2010/11 Test Year
Allocation Results of Cost of Service Elements
Rates Reflecting Order 128/09

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		18,144,318	1,130	220,449	310,796	149,017	241,108	21,198	252	476	7,731
Amortization of Cust. Contributions		-996,299	-267	-77,637	-374,334	-151,141	-48,478	0	0	0	0
Depreciation: Common Assets		4,251,000	235	39,739	45,819	14,378	52,704	56,676	673	1,272	20,671
Amortization Expense (Deferreds)		1,050,416	53	12,627	24,754	8,750	14,609	0	0	0	108,000
Demand Side Management Amortization Expense (Deferred)		4,918,053	0	49,181	0	0	0	0	0	0	0
Furnace Replacement Program		3,800,000	0	0	0	0	0	0	0	0	0
Ex-Franchise Depreciation & Amortization		0	0	0	0	0	0	0	0	0	0
Total Depreciation & Amortization Expenses		**31,167,487**	**1,152**	**244,359**	**7,035**	**21,004**	**259,943**	**77,874**	**925**	**1,747**	**136,402**
V. CAPITAL & OTHER TAXES											
Municipal Taxes		15,664,700	886	209,887	411,455	145,449	242,822	0	0	0	0
Payroll Tax		780,780	43	7,299	8,416	2,641	9,680	10,410	124	234	3,797
Taxes on Common Assets		218,000	14	2,575	2,756	1,112	4,764	4,331	55	104	109
Corporate Capital Tax		2,768,746	177	32,707	35,004	14,129	60,509	55,001	696	1,316	1,382
Business Taxes		0	0	0	0	0	0	0	0	0	0
Other		0	0	0	0	0	0	0	0	0	0
Income Taxes		4,507,827	288	53,251	56,991	23,004	98,515	89,548	1,134	2,143	2,249
Total Taxes		**23,940,053**	**1,408**	**305,719**	**514,621**	**186,335**	**416,290**	**159,290**	**2,009**	**3,796**	**7,536**
VI. FINANCE EXPENSE		**19,257,379**	**1,226**	**225,402**	**243,463**	**98,272**	**416,148**	**382,549**	**4,844**	**9,154**	**9,609**
VII. CORPORATE ALLOCATION		**12,000,000**	**764**	**140,457**	**151,711**	**61,237**	**259,318**	**238,380**	**3,018**	**5,704**	**5,988**
VIII. NET INCOME (LOSS)		**3,000,000**	**191**	**35,114**	**37,928**	**15,309**	**64,829**	**59,595**	**755**	**1,426**	**1,497**
COST OF SERVICE SUMMARY											
COST OF GAS		395,868,151	7,266	1,074,216	190,878	323,789	1,819,540	333,046,453	4,221,998	7,978,629	5,837,350
OTHER REVENUE		-2,025,790	-5	-331	-175	-407	-840	0	0	0	0
OPERATING EXPENSES											
President & CEO		1,097,000	53	7,798	11,824	3,710	13,664	14,626	174	328	5,334
Finance & Administration		11,480,473	601	109,762	200,915	52,175	116,313	917,993	10,898	20,596	115,806
Transmission & Distribution		7,633,000	826	283,198	130,447	33,955	228,135	0	0	0	0
Power Supply		232,000	13	4,264	12,598	3,099	5,778	0	0	0	0
Customer Service & Marketing		49,509,000	2,378	248,894	398,179	143,656	503,377	0	0	0	219,000
Adjustments to Income		-9,608,000	-532	-89,817	-103,559	-32,497	-119,121	-128,097	-1,521	-2,874	-46,719
Sub-total		60,343,473	3,340	564,099	650,404	204,099	748,146	804,522	9,551	18,050	293,421
DEPRECIATION & AMORTIZATION		31,167,487	1,152	244,359	7,035	21,004	259,943	77,874	925	1,747	136,402
CAPITAL & OTHER TAXES		23,940,053	1,408	305,719	514,621	186,335	416,290	159,290	2,009	3,796	7,536
FINANCE EXPENSE		19,257,379	1,226	225,402	243,463	98,272	416,148	382,549	4,844	9,154	9,609
CORPORATE ALLOCATION		12,000,000	764	140,457	151,711	61,237	259,318	238,380	3,018	5,704	5,988
NET INCOME		3,000,000	191	35,114	37,928	15,309	64,829	59,595	755	1,426	1,497
COST OF SERVICE		543,550,753	15,341	2,589,035	1,795,866	909,638	3,983,374	334,768,662	4,243,099	8,018,507	6,291,802

Centra Gas Manitoba Inc.
Reflecting Order 128/09
Tab 10 - Schedule Index

Centra Gas Manitoba Inc.
2010/11 Test Year
Bill Impact Comparison
Rates Reflecting Order 128/09

1	**BILLED VS. BILLED**													
2														
3					**Nov 1/09 BILLED RATES**				**2010/11 TY BILLED RATES**				**BILL IMPACTS**	
4														
5		Load	Annual Use		Basic Chg	Demand	Commodity	Annual	Basic Chg	Demand	Commodity	Annual	$	%
6		Factor	10^3m^3	Mcf										
7														
8	Small General Service		1.00	35	$156	$0	$354	$510	$168	$0	$354	$522	$12	2.35%
9			1.98	70	$156	$0	$702	$858	$168	$0	$702	$870	$12	1.40%
10	*(Typical Residential Customer)*		2.53	89	$156	$0	$896	$1,052	$168	$0	$896	$1,064	$12	1.14%
11			2.80	99	$156	$0	$992	$1,148	$168	$0	$992	$1,160	$12	1.05%
12			3.20	113	$156	$0	$1,133	$1,289	$168	$0	$1,133	$1,301	$12	0.93%
13			3.68	130	$156	$0	$1,303	$1,459	$168	$0	$1,303	$1,471	$12	0.82%
14			11.33	400	$156	$0	$4,009	$4,165	$168	$0	$4,009	$4,177	$12	0.29%
15														
16	Large General Service		11.33	400	$840	$0	$3,407	$4,247	$924	$0	$3,407	$4,331	$84	1.98%
17			59.49	2,100	$840	$0	$17,885	$18,725	$924	$0	$17,885	$18,809	$84	0.45%
18			679.87	24,000	$840	$0	$204,398	$205,238	$924	$0	$204,398	$205,322	$84	0.04%
19														
20	High Volume Firm	25%	850	30,000	$12,486	$48,565	$207,033	$268,084	$13,456	$47,792	$206,148	$267,397	($687)	-0.26%
21		40%	1,416	50,000	$12,486	$50,588	$345,055	$408,129	$13,456	$49,784	$343,580	$406,820	($1,309)	-0.32%
22		40%	2,833	100,000	$12,486	$101,177	$690,109	$803,772	$13,456	$99,568	$687,160	$800,184	($3,588)	-0.45%
23		75%	850	30,000	$12,486	$16,188	$207,033	$235,707	$13,456	$15,931	$206,148	$235,535	($172)	-0.07%
24		75%	1,416	50,000	$12,486	$26,981	$345,055	$384,521	$13,456	$26,551	$343,580	$383,588	($933)	-0.24%
25		75%	2,833	100,000	$12,486	$53,961	$690,109	$756,556	$13,456	$53,103	$687,160	$753,719	($2,837)	-0.37%
26														
27	Cooperative	35%	250	8,825	$3,603	$9,360	$57,531	$70,494	$3,299	$9,316	$57,175	$69,790	($704)	-1.00%
28		35%	350	12,355	$3,603	$13,105	$80,543	$97,250	$3,299	$13,042	$80,045	$96,387	($864)	-0.89%
29		35%	500	17,650	$3,603	$18,721	$115,061	$137,385	$3,299	$18,632	$114,350	$136,281	($1,104)	-0.80%
30														
31	Mainline Firm	40%	2,833	100,000	$17,943	$129,054	$666,738	$813,734	$28,359	$122,405	$662,750	$813,514	($221)	-0.03%
32		40%	14,164	500,000	$17,943	$645,270	$3,333,690	$3,996,902	$28,359	$612,027	$3,313,749	$3,954,134	($42,768)	-1.07%
33		40%	28,328	1,000,000	$17,943	$1,290,540	$6,667,379	$7,975,862	$28,359	$1,224,053	$6,627,498	$7,879,910	($95,952)	-1.20%
34		75%	2,833	100,000	$17,943	$68,829	$666,738	$753,509	$28,359	$65,283	$662,750	$756,391	$2,882	0.38%
35		75%	14,164	500,000	$17,943	$344,144	$3,333,690	$3,695,776	$28,359	$326,414	$3,313,749	$3,668,522	($27,254)	-0.74%
36		75%	28,328	1,000,000	$17,943	$688,288	$6,667,379	$7,373,610	$28,359	$652,828	$6,627,498	$7,308,685	($64,925)	-0.88%
37														
38	Special Contract	94%	451,570	15,940,855	$1,550,079	$0	$161,762	$1,711,841	$1,634,224	$0	$180,628	$1,814,852	$103,010	6.02%
39														
40	Power Stations	4%	12,117	427,742	$304,393	$147,562	$272,116	$724,071	$279,253	$280,272	$270,686	$830,210	$106,139	14.66%
41														
42	Interruptible Sales	25%	850	30,000	$12,346	$27,185	$205,259	$244,790	$12,546	$26,057	$203,969	$242,571	($2,219)	-0.91%
43		40%	2,833	100,000	$12,346	$56,635	$684,197	$753,178	$12,546	$54,285	$679,895	$746,726	($6,452)	-0.86%
44		40%	14,164	500,000	$12,346	$283,177	$3,420,984	$3,716,508	$12,546	$271,427	$3,399,477	$3,683,450	($33,058)	-0.89%
45		75%	850	30,000	$12,346	$9,062	$205,259	$226,667	$12,546	$8,686	$203,969	$225,200	($1,467)	-0.65%
46		75%	2,833	100,000	$12,346	$30,206	$684,197	$726,749	$12,546	$28,952	$679,895	$721,393	($5,355)	-0.74%
47		75%	14,164	500,000	$12,346	$151,028	$3,420,984	$3,584,358	$12,546	$144,761	$3,399,477	$3,556,784	($27,574)	-0.77%

Centra Gas Manitoba Inc.
2010/11 Test Year
Bill Impact Comparison
Rates Reflecting Order 128/09

Line	BASE VS. BASE	Load Factor	Annual Use 10³m³	Mcf	Nov 1/09 BASE RATES Basic Chg	Demand	Commodity	Annual	2010/11 TY BASE RATES Basic Chg	Demand	Commodity	Annual	BASE IMPACTS $	%
8	Small General Service		1.00	35	$156	$0	$339	$495	$168	$0	$339	$507	$12	2.43%
9			1.98	70	$156	$0	$670	$826	$168	$0	$670	$838	$12	1.45%
10	*(Typical Residential Customer)*		2.53	89	$156	$0	$858	$1,014	$168	$0	$858	$1,026	$12	1.18%
11			2.80	99	$156	$0	$949	$1,105	$168	$0	$949	$1,117	$12	1.09%
12			3.20	113	$156	$0	$1,084	$1,240	$168	$0	$1,084	$1,252	$12	0.97%
13			3.68	130	$156	$0	$1,247	$1,403	$168	$0	$1,247	$1,415	$12	0.86%
14			11.33	400	$156	$0	$3,836	$3,992	$168	$0	$3,836	$4,004	$12	0.30%
16	Large General Service		11.33	400	$840	$0	$3,251	$4,091	$924	$0	$3,251	$4,175	$84	2.05%
17			59.49	2,100	$840	$0	$17,067	$17,907	$924	$0	$17,067	$17,991	$84	0.47%
18			679.87	24,000	$840	$0	$195,049	$195,889	$924	$0	$195,049	$195,973	$84	0.04%
20	High Volume Firm	25%	850	30,000	$12,486	$36,278	$204,250	$253,015	$13,456	$35,506	$203,366	$252,328	($687)	-0.27%
21		40%	1,416	50,000	$12,486	$37,790	$340,417	$390,693	$13,456	$36,985	$338,943	$389,384	($1,309)	-0.34%
22		40%	2,833	100,000	$12,486	$75,580	$680,834	$768,900	$13,456	$73,971	$677,885	$765,312	($3,588)	-0.47%
23		75%	850	30,000	$12,486	$12,093	$204,250	$228,829	$13,456	$11,835	$203,366	$228,657	($172)	-0.08%
24		75%	1,416	50,000	$12,486	$20,155	$340,417	$373,058	$13,456	$19,725	$338,943	$372,125	($933)	-0.25%
25		75%	2,833	100,000	$12,486	$40,309	$680,834	$733,630	$13,456	$39,451	$677,885	$730,793	($2,837)	-0.39%
27	Cooperative	35%	250	8,825	$3,603	$9,360	$55,681	$68,644	$3,299	$9,316	$55,325	$67,940	($704)	-1.02%
28		35%	350	12,355	$3,603	$13,105	$77,953	$94,660	$3,299	$13,042	$77,455	$93,797	($864)	-0.91%
29		35%	500	17,650	$3,603	$18,721	$111,361	$133,685	$3,299	$18,632	$110,650	$132,581	($1,104)	-0.83%
31	Mainline Firm	40%	2,833	100,000	$17,943	$112,471	$640,515	$770,928	$28,359	$105,822	$636,527	$770,707	($221)	-0.03%
32		40%	14,164	500,000	$17,943	$562,353	$3,202,573	$3,782,869	$28,359	$529,110	$3,182,633	$3,740,101	($42,768)	-1.13%
33		40%	28,328	1,000,000	$17,943	$1,124,707	$6,405,147	$7,547,796	$28,359	$1,058,219	$6,365,266	$7,451,844	($95,952)	-1.27%
34		75%	2,833	100,000	$17,943	$59,984	$640,515	$718,442	$28,359	$56,438	$636,527	$721,324	$2,882	0.40%
35		75%	14,164	500,000	$17,943	$299,922	$3,202,573	$3,520,438	$28,359	$282,192	$3,182,633	$3,493,183	($27,254)	-0.77%
36		75%	28,328	1,000,000	$17,943	$599,844	$6,405,147	$7,022,933	$28,359	$564,384	$6,365,266	$6,958,008	($64,925)	-0.92%
38	Special Contract	94%	451,570	15,940,860	$1,550,079	$0	$161,762	$1,711,841	$1,634,224	$0	$180,628	$1,814,852	$103,010	6.02%
40	Power Stations	4%	12,117	427,743	$304,393	$153,119	$318,897	$776,409	$279,253	$285,829	$317,466	$882,548	$106,139	13.67%
42	Interruptible Sales	25%	850	30,000	$12,346	$18,607	$198,962	$229,915	$12,546	$17,479	$197,672	$227,696	($2,219)	-0.97%
43		40%	2,833	100,000	$12,346	$38,765	$663,207	$714,318	$12,546	$36,415	$658,906	$707,866	($6,452)	-0.90%
44		40%	14,164	500,000	$12,346	$193,824	$3,316,035	$3,522,205	$12,546	$182,074	$3,294,528	$3,489,148	($33,058)	-0.94%
45		75%	850	30,000	$12,346	$6,202	$198,962	$217,511	$12,546	$5,826	$197,672	$216,044	($1,467)	-0.67%
46		75%	2,833	100,000	$12,346	$20,675	$663,207	$696,228	$12,546	$19,421	$658,906	$690,872	($5,355)	-0.77%
47		75%	14,164	500,000	$12,346	$103,373	$3,316,035	$3,431,754	$12,546	$97,106	$3,294,528	$3,404,180	($27,574)	-0.80%

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES - NO RIDERS)

Territory:	Entire natural gas service area of Company, including all zones
Availability:	
SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m3.
HVF:	For gas delivered through one meter at annual volumes greater than 680,000 m3.
CO-OP:	For gas delivered to natual gas distribution cooperatives.
MLC:	For gas delivered through one meter to consumers served from the Transmission system.
Special Contract:	For gas delivered under the terms of a Special Contract with the Company.
Power Station:	For gas delivered under the terms of a Special Contract with the Company.

Rates:		**Distribution to Customers**			
	Transportation to Centra	**Sales Service**	**T-Service**	**Primary Gas Supply**	**Supplemental Gas Supply[1]**
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$13.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$70.00	$70.00	N/A	N/A
High Volume Firm (HVF)	N/A	$1,040.53	$1,040.53	N/A	N/A
Cooperative (CO-OP)	N/A	$300.23	$300.23	N/A	N/A
Main Line Class (MLC)	N/A	$1,495.21	$1,495.21	N/A	N/A
Special Contract	N/A	N/A	$129,173.28	N/A	N/A
Power Station	N/A	N/A	$12,683.06	N/A	N/A
Monthly Demand Charge ($/m^3/month)					
High Volume Firm Class (HVF)	$0.1716	$0.1531	$0.1531	N/A	N/A
Cooperative (CO-OP)	$0.2671	$0.1315	$0.1315	N/A	N/A
Main Line Class (MLC)	$0.3090	$0.1740	$0.1740	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0154	N/A	N/A
Commodity Volumetric Charge: ($/m^3)					
Small General Class (SGC)	$0.0361	$0.0885	N/A	$0.2139	$0.1578
Large General Class (LGC)	$0.0352	$0.0378	$0.0378	$0.2139	$0.1578
High Volume Firm (HVF)	$0.0170	$0.0094	$0.0094	$0.2139	$0.1578
Cooperative (CO-OP)	$0.0087	$0.0001	$0.0001	$0.2139	$0.1578
Main Line Class (MLC)	$0.0091	$0.0031	$0.0031	$0.2139	$0.1578
Special Contract	N/A	N/A	$0.0004	N/A	N/A
Power Station	N/A	N/A	$0.0263	N/A	N/A

¹ Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill:	Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.
Effective:	Rates to be charged for all billings based on gas consumed on and after February 1, 2008.

* Including Firm Mainline Delivery combined with Interruptible Supply

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES - NO RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability: For any consumer at one location whose annual natural gas requirements equal or exceed 680,000 m³ and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:

	Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply1
Basic Monthly Charge: ($/month)					
Interruptible Service	N/A	$1,028.85	$1,028.85	N/A	N/A
Mainline Interruptible (with firm delivery)	N/A	$1,495.21	$1,495.21	N/A	N/A
Monthly Demand Charge ($/m³ /month)					
Interruptible Service	$0.0804	$0.0861	$0.0861	N/A	N/A
Mainline Interruptible (with firm delivery)	$0.1237	$0.1740	$0.1740	N/A	N/A
Commodity Volumetric Charge: ($/m³)					
Interruptible Service	$0.0128	$0.0074	$0.0074	$0.2139	$0.2682
Mainline Interruptible (with firm delivery)	$0.0096	$0.0031	$0.0031	$0.2139	$0.2682

Alternate Supply Service:	Negotiated
Gas Supply (Interruptible Sales and Mainline Interruptible)	Cost of Gas
Delivery - Interruptible Class	$0.0102
Delivery - Mainline Interruptible Class	$0.0088

¹ Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to Basic Monthly Charge as described above, plus Demand charges as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after February 1, 2008.

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES PLUS RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability:

SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m3.
HVF:	For gas delivered through one meter at annual volumes greater than 680,000 m3.
CO-OP:	For gas delivered to natual gas distribution cooperatives.
MLC:	For gas delivered through one meter to consumers served from the Transmission system.
Special Contract:	For gas delivered under the terms of a Special Contract with the Company.
Power Station:	For gas delivered under the terms of a Special Contract with the Company.

Rates:

		Distribution to Customers			
	Transportation to Centra	Sales Service	T-Service	Primary Gas Supply	Supplemental Gas Supply1
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$13.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$70.00	$70.00	N/A	N/A
High Volume Firm (HVF)	N/A	$1,040.53	$1,040.53	N/A	N/A
Cooperative (CO-OP)	N/A	$300.23	$300.23	N/A	N/A
Main Line Class (MLC)	N/A	$1,495.21	$1,495.21	N/A	N/A
Special Contract	N/A	N/A	$129,173.28	N/A	N/A
Power Station	N/A	N/A	$12,683.06	N/A	N/A
Monthly Demand Charge ($/m^3/month)					
High Volume Firm Class (HVF)	$0.2805	$0.1541	$0.1541	N/A	N/A
Cooperative (CO-OP)	$0.2671	$0.1315	$0.1315	N/A	N/A
Main Line Class (MLC)	$0.3784	$0.1759	$0.1759	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0148	N/A	N/A
Commodity Volumetric Charge: ($/m^3)					
Small General Class (SGC)	$0.0429	$0.0896	N/A	$0.2213	$0.1578
Large General Class (LGC)	$0.0404	$0.0390	$0.0371	$0.2213	$0.1578
High Volume Firm (HVF)	$0.0117	$0.0106	$0.0087	$0.2213	$0.1578
Cooperative (CO-OP)	$0.0087	$0.0001	$0.0001	$0.2213	$0.1578
Main Line Class (MLC)	$0.0099	$0.0042	$0.0023	$0.2213	$0.1578
Special Contract	N/A	N/A	$0.0004	N/A	N/A
Power Station	N/A	N/A	$0.0225	N/A	N/A

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after February 1, 2008.

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES PLUS RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability: For any consumer at one location whose annual natural gas requirements equal or exceed 680,000 m³ and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:

		Distribution to Customers			
	Transportation to Centra	**Sales Service**	**T-Service**	**Primary Gas Supply**	**Supplemental Gas Supply1**
Basic Monthly Charge: ($/month)					
Interruptible Service	N/A	$1,028.85	$1,028.85	N/A	N/A
Mainline Interruptible (with firm delivery)	N/A	$1,495.21	$1,495.21	N/A	N/A
Monthly Demand Charge ($/m^3 /month)					
Interruptible Service	$0.1565	$0.0868	$0.0868	N/A	N/A
Mainline Interruptible (with firm delivery)	$0.2408	$0.1759	$0.1759	N/A	N/A
Commodity Volumetric Charge: ($/m^3)					
Interruptible Service	$0.0113	$0.0089	$0.0068	$0.2213	$0.2682
Mainline Interruptible (with firm delivery)	$0.0063	$0.0042	$0.0023	$0.2213	$0.2682

Alternate Supply Service:	Negotiated
Gas Supply (Interruptible Sales and Mainline Interruptible)	Cost of Gas
Delivery - Interruptible Class	$0.0117
Delivery - Mainline Interruptible Class	$0.0088

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.
[2] Supplemental Refund Rider; refunded over total annual volumes

Minimum Monthly Bill: Equal to Basic Monthly Charge as described above, plus Demand charges as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after February 1, 2008.

CENTRA GAS MANITOBA INC. **Schedule 10.2.2**
Appendix A- Schedule of Sales and Transportation Services and Rates **Page 1 of 4**
Rates Reflecting B/O 128/09

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability:

SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m³
HVF:	For gas delivered through one meter at annual volumes greater than 680,000 m³
CO-OP:	For gas delivered to natural gas distribution cooperatives
MLC:	For gas delivered through one meter to customers served from the Transmission system
Special Contract:	For gas delivered under the terms of a Special Contract with the Company
Power Station:	For gas delivered under the terms of a Special Contract with the Company

Rates:

		Distribution to Customers			
	Transportation to Centra	**Sales Service**	**T-Service**	**Primary Gas Supply**	**Supplemental Gas Supply[1]**
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm (HVF)	N/A	$1,121.37	$1,121.37	N/A	N/A
Cooperative (CO-OP)	N/A	$274.95	$274.95	N/A	N/A
Main Line Class (MLC)	N/A	$2,363.23	$2,363.23	N/A	N/A
Special Contract	N/A	N/A	$136,185.32	N/A	N/A
Power Station	N/A	N/A	$11,635.54	N/A	N/A
Monthly Demand Charge ($/m^3/month)					
High Volume Firm Class (HVF)	$0.1665	$0.1512	$0.1512	N/A	N/A
Cooperative (CO-OP)	$0.2663	$0.1304	$0.1304	N/A	N/A
Main Line Class (MLC)	$0.2960	$0.1585	$0.1585	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0287	N/A	N/A
Commodity Volumetric Charge: ($/m^3)					
Small General Class (SGC)	$0.0361	$0.0885	N/A	$0.2139	$0.1584
Large General Class (LGC)	$0.0352	$0.0378	$0.0378	$0.2139	$0.1584
High Volume Firm (HVF)	$0.0157	$0.0097	$0.0097	$0.2139	$0.1584
Cooperative (CO-OP)	$0.0073	$0.0001	$0.0001	$0.2139	$0.1584
Main Line Class (MLC)	$0.0077	$0.0031	$0.0031	$0.2139	$0.1584
Special Contract	N/A	N/A	$0.0004	N/A	N/A
Power Station	N/A	N/A	$0.0262	N/A	N/A

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after May 1, 2010

Approved by Board Order: 128/09
Effective from: May 1, 2010
Date Implemented: May 1, 2010

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability: For any consumer at one location whose annual natural gas requirements equal or exceed 680,000 m³ and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:

		Distribution to Customers			
	Transportation to Centra	Sales Service	T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Interruptible Service	N/A	$1,045.47	$1,045.47	N/A	N/A
Mainline Interruptible (with firm delivery)	N/A	$2,363.23	$2,363.23	N/A	N/A
Monthly Demand Charge ($/m^3/month)					
Interruptible Service	$0.0787	$0.0777	$0.0777	N/A	N/A
Mainline Interruptible (with firm delivery)	$0.1211	$0.1585	$0.1585	N/A	N/A
Commodity Volumetric Charge: ($/m^3)					
Interruptible Service	$0.0115	$0.0072	$0.0072	$0.2139	$0.2631
Mainline Interruptible (with firm delivery)	$0.0083	$0.0031	$0.0031	$0.2139	$0.2631

Alternate Supply Service:	Negotiated
Gas Supply (Interruptible Sales and Mainline Interruptible)	Cost of Gas
Delivery - Interruptible Class	$0.0098
Delivery - Mainline Interruptible Class	$0.0083

¹ Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to Basic Monthly Charge as described above, plus Demand charges as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after May 1, 2010

Approved by Board Order: 128/09
Effective from: May 1, 2010
Date Implemented: May 1, 2010

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES PLUS RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability:

SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m³
HVF:	For gas delivered to natural gas distribution cooperatives
CO-OP:	For gas delivered through one meter at annual volumes greater than 680,000 m³
MLC:	For gas delivered through one meter to customers served from the Transmission system
Special Contract:	For gas delivered under the terms of a Special Contract with the Company
Power Station:	For gas delivered under the terms of a Special Contract with the Company

Rates:

		Distribution to Customers			
	Transportation to Centra	**Sales Service**	**T-Service**	**Primary Gas Supply**	**Supplemental Gas Supply[1]**
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm (HVF)	N/A	$1,121.37	$1,121.37	N/A	N/A
Cooperative (CO-OP)	N/A	$274.95	$274.95	N/A	N/A
Main Line Class (MLC)	N/A	$2,363.23	$2,363.23	N/A	N/A
Special Contract	N/A	N/A	$136,185.32	N/A	N/A
Power Station	N/A	N/A	$11,635.54	N/A	N/A
Monthly Demand Charge ($/m^3/month)					
High Volume Firm Class (HVF)	$0.2754	$0.1522	$0.1522	N/A	N/A
Cooperative (CO-OP)	$0.2663	$0.1304	$0.1304	N/A	N/A
Main Line Class (MLC)	$0.3654	$0.1604	$0.1604	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0281	N/A	N/A
Commodity Volumetric Charge: ($/m^3)					
Small General Class (SGC)	$0.0429	$0.0896	N/A	$0.2213	$0.1584
Large General Class (LGC)	$0.0404	$0.0390	$0.0371	$0.2213	$0.1584
High Volume Firm (HVF)	$0.0103	$0.0109	$0.0091	$0.2213	$0.1584
Cooperative (CO-OP)	$0.0073	$0.0003	$0.0001	$0.2213	$0.1584
Main Line Class (MLC)	$0.0085	$0.0041	$0.0023	$0.2213	$0.1584
Special Contract	N/A	N/A	$0.0004	N/A	N/A
Power Station	N/A	N/A	$0.0223	N/A	N/A

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after May 1, 2010

Approved by Board Order: 128/09
Effective from: May 1, 2010
Date Implemented: May 1, 2010

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES PLUS RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability: For any consumer at one location whose annual natural gas requirements equal or exceed 680,000 m³ and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:

		Distribution to Customers			
	Transportation to Centra	**Sales Service**	**T-Service**	**Primary Gss Supply**	**Supplemental Gas Supply[1]**
Basic Monthly Charge: ($/month)					
Interruptible Service	N/A	$1,045.47	$1,045.47	N/A	N/A
Mainline Interruptible (with firm delivery)	N/A	$2,363.23	$2,363.23	N/A	N/A
Monthly Demand Charge ($/m^3/month)					
Interruptible Service	$0.1548	$0.0784	$0.0784	N/A	N/A
Mainline Interruptible (with firm delivery)	$0.2381	$0.1604	$0.1604	N/A	N/A
Commodity Volumetric Charge: ($/m^3)					
Interruptible Service	$0.0100	$0.0087	$0.0066	$0.2213	$0.2631
Mainline Interruptible (with firm delivery)	$0.0048	$0.0041	$0.0023	$0.2213	$0.2631

Alternate Supply Service:	Negotiated
Gas Supply (Interruptible Sales and Mainline Interruptible)	Cost of Gas
Delivery - Interruptible Class	$0.0113
Delivery - Mainline Interruptible Class	$0.0094

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to Basic Monthly Charge as described above, plus Demand charges as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after May 1, 2010

Approved by Board Order: 128/09
Effective from: May 1, 2010
Date Implemented: May 1, 2010

Manitoba Hydro
PO Box 815 • Winnipeg Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 22nd floor 360 Portage Ave
Telephone / N° de téléphone : (204) 360-3468 • Fax / N° de télécopieur : (204) 360-6147
mmurphy@hydro.mb.ca

April 29, 2010

PUBLIC UTILITIES BOARD OF MANITOBA
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

ATTENTION: Mr. G. Gaudreau, Executive Director

Dear Mr. Gaudreau:

Re: Centra Gas Manitoba Inc. ("Centra")
2009/10 & 2010/11 General Rate Application
2010/11 Cost of Gas Application
Revised Schedules Flowing from Board Order 41/10

On April 27, 2010 the Manitoba Public Utilities Board ("PUB") issued Order 41/10 arising from Centra's 2010/11 Cost of Gas Application and included direction with respect to non-gas costs flowing from Centra's 2009/10 & 2010/11 General Rate Application. The PUB directed Centra to file revised schedules for revenue requirement, forecast gas costs, cost allocation, base and billed rates, and customer bill impacts that reflect the directives of Order 41/10.

Centra is enclosing herewith the requested revisions and seeks approval of the revised rate schedules in order to implement new Sales and Transportation Rates on May 1, 2010. In addition, Centra is seeking approval of the bill insert that has been revised to reflect the annual bill impacts flowing from these schedules.

In accordance with Order 41/10, Centra has made the following adjustments to non-gas costs and rates flowing from Centra's 2009/10 & 2010/11 General Rate Application:

- An adjustment to revenue requirement for the interest charged on common assets and inventory for 2009/10 and 2010/11 utilizing forecasted interest rates consistent with those directed in 128/09; and
- A recalculation of the 2010/11 Sales and Transportation rates for all customer classes other than the SGS and LGS classes by incorporating a net income of $2.4 million in the Cost Allocation Model.

Centra notes that the adjustment to revenue requirement associated with the change in interest charged on common assets and inventories results in a level of net income of $2.505 million. For rate setting purposes, Centra has allocated a net income of $2.353 million, as is shown on the reconciliation Schedule 9.0.0 attached.

Centra has also made an adjustment to non-Primary Gas costs flowing from Order 41/10, to apply the actual CAD/USD exchange rate experienced year-to-date and a forecast of $1.02 CAD/USD to October 31, 2010. The revised exchange rate results in a reduction in the forecast of non-primary gas costs of approximately $1.6 million.

Centra's proposed Sales and Transportation rates for May 1, 2010, as attached in Schedule 8.2.0, incorporate the non-gas rate changes and the revised non-Primary Gas rate changes flowing from Order 41/10 as described above. The resulting bill impacts from these rates are shown on Schedule 8.1.0. As shown on page 1 of Schedule 8.1.0, the billed rate impact for the typical residential customer consuming 2,530 cubic metres annually is a decrease of approximately $66 or 6.4%.

The combined annual bill impacts of rates flowing from Board Order 41/10 are summarized in the following table:

Summary of Annual Bill Impacts (May 1, 2010)

				Combined Annual Impacts (Order 41/10)	
Customer Class	**Consumption**		**Load Factor**	**$ Impact**	**% Change**
SGS	1.0	10^3M^3		($19)	-3.7%
	2.5	10^3M^3		($66)	-6.4%
	11.3	10^3M^3		($335)	-8.2%
LGS	11.3	10^3M^3		($247)	-6.0%
	679.9	10^3M^3		($19,751)	-9.9%
HVF	850	10^3M^3	25%	($19,002)	-7.3%
	12,600	10^3M^3	75%	($286,895)	-9.0%
Mainline	2,833	10^3M^3	40%	($61,758)	-7.8%
	41,000	10^3M^3	75%	($990,000)	-9.6%
Special Contract	451,570	10^3M^3	94%	($101,235)	-5.9%
Power Stations	12,117	10^3M^3	5%	($311,407)	-44.5%
Interruptible	850	10^3M^3	25%	($44,817)	-17.6%
	14,164	10^3M^3	75%	($701,819)	-18.8%

In order to implement the billing for new rates on May 1, 2010, Centra respectfully requests approval of these schedules and the bill insert by the end of business on Friday, April 30, 2010.

Copies of this letter have been provided to the PUB advisors and all registered interveners from Centra's 2010/11 Cost of Gas Application. If you have any questions with respect to this submission or require a paper copy, please contact the writer at 360-3468, or Greg Barnlund at 360-5243.

Yours truly,
MANITOBA HYDRO LAW DEPARTMENT
Per:

M Murphy

Marla D. Murphy
Barrister and Solicitor
Att.

cc: Mr. B. Peters, Fillmore Riley
Mr. R. Cathcart, Cathcart Advisors Inc.
Mr. B. Ryall, Energy Consultants Inc.
Registered Intervenors

Centra Gas Manitoba Inc.
2009/10 & 2010/11 General Rate Application
Final Schedules
Reflecting Orders 128/09 and 41/10

CENTRA GAS MANITOBA INC.
Summary of Additional Revenue Requested

Schedule 3.0.0
Reflecting Order 128/09 & 41/10

($000'S)

2009/10 and 2010/11 Test Year

Apr 29, '10

	2008/09 Approved	2009/10 Test Year	Net Change	2008/09 Approved	2010/11 Test Year	Net Change
	[1]	[2]	[3]	[4]	[5]	[6]
Cost of Gas	407,142	318,785	(88,357)	407,142	331,442	(75,700)
Other Income	(2,115)	(2,026)	89	(2,115)	(2,026)	89
Operating & Administrative	58,000	59,160	1,160	58,000	60,343	2,343
Depreciation & Amortization	23,072	25,047	1,975	23,072	27,367	4,295
Furnace Replacement Program	3,855	3,800	(55)	3,855	3,800	(55)
Capital & Other Taxes	23,063	23,703	640	23,063	23,940	877
Finance Expense	22,154	19,725	(2,429)	22,154	19,105	(3,049)
Corporate Allocation	12,000	12,000	-	12,000	12,000	-
Net Income (Loss)	3,000	2,147	(853)	3,000	2,505	(495)
Revenue Requirement	550,171	462,341	(87,830)	550,171	478,476	(71,694)

CENTRA GAS MANITOBA INC.
Summary of Revenue Requirement
Cost of Service Methodology

Schedule 3.1.0
Reflecting Order 128/09 & 41/10

($000'S)

2009/10 and 2010/11 Test Year
Apr 29, '10

	2009/10 Applied[1]	2009/10 Test Year	Net Change	2010/11 Applied[1]	2010/11 Test Year	Net Change
	[1]	[2]	[3]	[4]	[5]	[6]
Cost of Gas	318,785	318,785	-	331,442	331,442	-
Other Income	(2,026)	(2,026)	-	(2,026)	(2,026)	-
Operating & Administrative	59,160	59,160	-	60,343	60,343	-
Depreciation & Amortization	28,545	25,047	(3,498)	32,285	27,367	(4,918)
Capital & Other Taxes	23,701	23,703	2	23,934	23,940	6
Finance Expense	20,992	19,725	(1,267)	21,017	19,105	(1,912)
Furnace Replacement Program	-	3,800	3,800	-	3,800	3,800
Provision for Accounting & Other Changes	-	-	-	5,000	-	(5,000)
Corporate Allocation	12,000	12,000	-	12,000	12,000	-
Net Income (Loss)	2,869	2,147	(722)	2,814	2,505	(309)
Revenue Requirement	464,026	462,341	(1,685)	486,808	478,476	(8,332)

[1] This is based on the May 29th, 2009 Update Filing

CENTRA GAS MANITOBA INC.
Summary of Revenue Requirement & Rate Base
Rate Base Rate of Return Methodology

Schedule 3.1.1
Reflecting Order 128/09 & 41/10

($000'S)

2009/10 and 2010/11 Test Year

Apr 29, '10

	2009/10 Applied[1]	2009/10 Test Year	Net Change	2010/11 Applied[1]	2010/11 Test Year	Net Change
	[1]	[2]	[3]	[4]	[5]	[6]
Cost of Gas	318,785	318,785	-	331,442	331,442	-
Other Income	(2,026)	(2,026)	-	(2,026)	(2,026)	-
Operating & Administrative	59,160	59,160	-	60,343	60,343	-
Depreciation & Amortization	28,545	25,047	(3,498)	32,285	27,367	(4,918)
Capital & Other Taxes	23,701	23,703	2	23,934	23,940	6
Furnace Replacement Program	-	3,800	3,800	-	3,800	3,800
Provision for Accounting & Other Changes	-	-	-	5,000	-	(5,000)
Corporate Allocation	12,000	12,000	-	12,000	12,000	-
Return on Rate Base	33,334	32,767	(567)	34,180	32,262	(1,918)
Revenue Requirement	473,501	473,236	(263)	497,158	489,129	(8,030)
Gas Plant in Service	611,116	611,116	-	634,052	634,052	-
Accumulated Depreciation	(216,739)	(216,739)	-	(229,807)	(229,807)	-
Net Plant	394,377	394,377	-	404,245	404,245	-
Contributions in Aid of Construction	(48,857)	(48,857)	-	(50,956)	(50,956)	-
Working Capital Allowance	117,939	117,975	36	133,315	132,576	(739)
Rate Base	463,459	463,496	36	486,603	485,864	(739)

[1] This is based on the May 29th, 2009 Update Filing

CENTRA GAS MANITOBA INC.
Summary of Cost of Service

2009/10 and 2010/11 Test Year

Schedule 4.0.0
Reflecting Order 128/09 & 41/10
($000'S)
Apr 29, '10

	2006/07 Actual	2007/08 Actual	2008/09 Forecast	2009/10 Test Year	2010/11 Test Year
	[1]	[2]	[3]	[4]	[5]
Cost of Gas	378,664	386,490	427,856	318,785	331,442
Other Income	(2,199)	(1,967)	(2,054)	(2,026)	(2,026)
Operating & Administrative	53,505	56,270	58,000	59,160	60,343
Depreciation & Amortization	18,323	23,293	25,413	25,047	27,367
Capital & Other Taxes	22,248	23,021	23,323	23,703	23,940
Finance Expense	22,095	21,711	22,225	19,725	19,105
Furnace Replacement Program	-	-	-	3,800	3,800
Corporate Allocation	12,000	12,000	12,000	12,000	12,000
Net Income (Loss)	1,075	5,899	3,038	2,147	2,505
Total Cost of Service	505,711	526,717	569,801	462,341	478,476
Less Cost of Gas	378,664	386,490	427,856	318,785	331,442
Non-Gas Cost of Service	127,047	140,228	141,945	143,556	147,034
% Change		10.4%	1.2%	1.1%	2.4%

CENTRA GAS MANITOBA INC.
Finance Expense - 2006/07 to 2010/11

Schedule 4.12.0
Reflecting Order 128/09 & 41/10
($000'S)
Apr 29, '10

	2006/07 Actual	2007/08 Actual	2008/09 Forecast	2009/10 Test Year	2010/11 Test Year
	[1]	[2]	[3]	[4]	[5]
Interest on Long Term Debt/Advances	13,762	13,547	13,760	14,928	14,404
Provincial Guarantee Fee on Long Term Debt	2,476	2,403	2,380	2,657	2,977
Amortization of Debt Discounts	1,692	1,253	1,256	1,262	298
Interest on Short Term Debt	3,349	4,665	4,384	511	879
Provincial Guarantee Fee on Short Term Debt	603	815	902	628	669
Interest on Common Assets	2,138	2,244	2,562	2,510	2,688
Interest on Inventory	24	32	24	23	26
Interest Capitalized	(1,958)	(3,270)	(3,101)	(2,826)	(2,843)
Other	9	22	58	31	7
Total Financing Expenses	22,095	21,711	22,225	19,725	19,105

CENTRA GAS MANITOBA INC.
Summary of Rate Base Rate of Return
Revenue Requirement & Rate Base

Schedule 5.0.0
Reflecting Order 128/09 & 41/10
($000'S)
Apr 29, '10

	2006/07 Actual	2007/08 Actual	2008/09 Forecast	2009/10 Test Year	2010/11 Test Year
	[1]	[2]	[3]	[4]	[5]
Cost of Gas	378,664	386,490	427,856	318,785	331,442
Other Income	(2,199)	(1,967)	(2,054)	(2,026)	(2,026)
Operating & Administrative	53,505	56,270	58,000	59,160	60,343
Depreciation & Amortization	18,323	23,293	25,413	25,047	27,367
Capital & Other Taxes	22,248	23,021	23,323	23,703	23,940
Furnace Replacement Program	-	-	-	3,800	3,800
Corporate Allocation	12,000	12,000	12,000	12,000	12,000
Return on Rate Base	34,757	33,039	34,704	32,767	32,262
Revenue Requirement from Gas Rates	517,298	532,146	579,242	473,236	489,129

	2006/07 Actual	2007/08 Actual	2008/09 Forecast	2009/10 Test Year	2010/11 Test Year
Gas Plant in Service	545,841	565,585	586,411	611,116	634,052
Accumulated Depreciation	(186,170)	(195,010)	(205,391)	(216,739)	(229,807)
Net Plant	359,671	370,575	381,020	394,377	404,245
Contributions in Aid of Construction	(46,639)	(46,974)	(46,450)	(48,857)	(50,956)
Working Capital Allowance	118,603	107,195	123,012	117,975	132,576
Rate Base	431,635	430,796	457,582	463,495	485,864

CENTRA GAS MANITOBA INC. **Schedule 5.6.3**

Working Capital Allowance **Reflecting Order 128/09 & 41/10**

($000'S)

2009/10 Test Year **Apr 29, '10**

	2009/10 Test Year	Daily Amounts (Col 1 / 365)	Lead (Lag) Days	Working Capital Required (Col 2 * Col 3)
	[1]	[2]	[3]	[4]
Cash Working Capital Requirement:				
Revenues	475,262	1,302	47.8	62,188
Cost of Gas	318,785	873	(39.2)	(34,263)
Operating and Administrative Expenses	56,554	155	(15.2)	(2,355)
Payroll Taxes	770	2	(15.2)	(32)
Capital and Other Taxes	18,279	50	(17.7)	(885)
Financing Expenses:				
Cost of Long Term Debt	19,573	54	(91.3)	(4,893)
Cost of Short Term Debt	1,194	3	(16.5)	(54)
Corporate Allocation	12,000	33	(15.2)	(500)
Cash Revenue Requirement Items	427,156	1,170	16.4	19,205
Reconciling Revenue Requirement Items:				
Bad Debt Expense	2,606			
Depreciation and Amortization Expense	25,047			
Furnace Replacement Program	3,800			
Income Taxes	4,654			
Return on Equity	12,000			
Total Revenue Requirement	475,262			
Non Cost of Service Tax Collections	48,815	134	1.0	132
Cash Working Capital Requirement				19,337
Other Working Capital Requirements:				
Gas in Storage				68,033
Security Deposits				(500)
Investment in DSM				31,105
Total Working Capital Allowance				117,975

CENTRA GAS MANITOBA INC. **Schedule 5.6.4**

Working Capital Allowance **Reflecting Order 128/09 & 41/10**

($000'S)

2010/11 Test Year **Apr 29, '10**

	2010/11 Test Year	Daily Amounts (Col 1 / 365)	Lead (Lag) Days	Working Capital Required (Col 2 * Col 3)
	[1]	[2]	[3]	[4]
Cash Working Capital Requirement:				
Revenues	491,154	1,346	47.8	64,267
Cost of Gas	331,442	908	(39.2)	(35,623)
Operating and Administrative Expenses	57,685	158	(15.2)	(2,402)
Payroll Taxes	781	2	(15.2)	(33)
Capital and Other Taxes	18,651	51	(17.7)	(903)
Financing Expenses:				
Cost of Long Term Debt	18,670	51	(91.3)	(4,668)
Cost of Short Term Debt	1,436	4	(16.5)	(65)
Corporate Allocation	12,000	33	(15.2)	(500)
Cash Revenue Requirement Items	440,665	1,207	16.6	20,074
Reconciling Revenue Requirement Items:				
Bad Debt Expense	2,658			
Depreciation and Amortization Expense	27,367			
Furnace Replacement Program	3,800			
Income Taxes	4,508			
Return on Equity	12,156			
Total Revenue Requirement	491,154			
Non Cost of Service Tax Collections	50,321	138	1.0	136
Cash Working Capital Requirement				20,210
Other Working Capital Requirements:				
Gas in Storage				75,808
Security Deposits				(500)
Investment in DSM				37,058
Total Working Capital Allowance				132,576

CENTRA GAS MANITOBA INC. **Schedule 5.7.3**
Overall Rate of Return **Reflecting Order 128/09 & 41/10**
($000'S)
2009/10 Test Year **Apr 29, '10**

	Capital Structure	Weight	Cost Rate	Weighted Cost of Capital
	[1]	[2]	[3]	[4]
Long Term Debt	265,835	51.9%	7.09%	3.68%
Short Term Debt	88,072	17.2%	1.50%	0.26%
Equity	158,772	31.0%	8.36%	2.59%
	512,679	100.0%		6.52%

CENTRA GAS MANITOBA INC. **Schedule 5.7.4**
Overall Rate of Return **Reflecting Order 128/09 & 41/10**
($000'S)
2010/11 Test Year **Apr 29, '10**

	Capital Structure	Weight	Cost Rate	Weighted Cost of Capital
	[1]	[2]	[3]	[4]
Long Term Debt	297,671	55.3%	5.94%	3.28%
Short Term Debt	79,521	14.8%	2.00%	0.30%
Equity	161,099	29.9%	8.36%	2.50%
	538,290	100.0%		6.08%

CENTRA GAS MANITOBA INC.
Return on Rate Base

Schedule 5.9.3
Reflecting Order 128/09 & 41/10
($000'S)

2009/10 Test Year
Apr 29, '10

	Rate Base	Weight	Cost Rate	Return
	[1]	[2]	[3]	[4]
Long Term Debt	463,495	51.9%	7.09%	17,039
Short Term Debt	463,495	17.2%	1.50%	1,194
Equity	463,495	31.0%	8.36%	12,000
		100.0%		30,233
Interest on Common Assets and Inventory				2,534
Total Return on Rate Base				32,767

CENTRA GAS MANITOBA INC.
Return on Rate Base

Schedule 5.9.4
Reflecting Order 128/09 & 41/10
($000'S)

2010/11 Test Year
Apr 29, '10

	Rate Base	Weight	Cost Rate	Return
	[1]	[2]	[3]	[4]
Long Term Debt	485,864	55.3%	5.94%	15,956
Short Term Debt	485,864	14.8%	2.00%	1,436
Equity	485,864	29.9%	8.36%	12,156
		100.0%		29,548
Interest on Common Assets and Inventory				2,714
Total Return on Rate Base				32,262

Centra Gas Manitoba Inc. **Sch 9.0.0**
2009/10 & 2010/11 General Rate Application **29-Apr-10**
Cost of Service vs. Cost Allocation Reconciliation
2010/11 Test Year ($000's)

	2010/11 Test Year Cost of Service	2010/11 Test Year Cost Allocation
Cost of Gas	331,442	395,868
Other Income	(2,026)	(2,026)
Operating & Administrative	60,343	60,343
Depreciation & Amortization	31,167	31,167
Capital & Other Taxes	23,940	23,940
Finance Expense	19,105	19,105
Corporate Allocation	12,000	12,000
Net Income (Loss)	2,505	2,353
Total Cost of Service	478,476	542,751

2010/11 Total Cost of Service (Sch. 4.0.0)	478,476
Less 2010/11 Fiscal Year Cost of Gas	(331,442)
Add 2008/09 Gas Year Cost of Gas	395,868
Less Net Income per Schedule 3.1.0	(2,505)
Add Net Income per B/O 41/10	2,353
2010/11 Cost Allocation (Sch. 9.2.0)	542,751

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Summary of Allocated Costs by Customer Class
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

Schedule 9.2.0

Cost of Service Elements

SGS	Demand	Energy	Customer	Total
Cost of Gas	17,006,199	5,198,805	0	22,205,004
Other Income	0	0	-2,002,960	-2,002,960
Operating & Maintenance Expenses	5,322,287	87,282	40,660,495	46,070,064
Depreciation & Amortization	3,394,926	8,040	21,017,604	24,420,570
Capital & Other Taxes	4,062,669	559,099	11,576,285	16,198,053
Finance Expense	2,416,042	1,422,364	8,807,793	12,646,199
Corporate Allocation	1,517,535	893,398	5,532,244	7,943,177
Net Income	297,563	175,180	1,084,781	1,557,525
Total Cost of Service	34,017,222	8,344,167	86,676,241	129,037,630

LGS	Demand	Energy	Customer	Total
Cost of Gas	11,828,276	3,710,898	0	15,539,174
Other Income	0	0	-19,169	-19,169
Operating & Maintenance Expenses	3,703,770	62,194	5,405,461	9,171,425
Depreciation & Amortization	2,045,187	5,727	3,249,123	5,300,038
Capital & Other Taxes	2,826,606	401,797	1,955,831	5,184,233
Finance Expense	1,679,697	1,022,200	1,579,564	4,281,461
Corporate Allocation	1,055,031	642,052	992,136	2,689,219
Net Income	206,874	125,896	194,541	527,311
Total Cost of Service	23,345,441	5,970,764	13,357,487	42,673,693

HVF	Demand	Energy	Customer	Total
Cost of Gas	2,642,130	981,724	0	3,623,854
Other Income	0	0	-1,902	-1,902
Operating & Maintenance Expenses	962,546	14,184	829,621	1,806,352
Depreciation & Amortization	478,097	1,279	217,064	696,440
Capital & Other Taxes	745,462	105,596	108,831	959,888
Finance Expense	442,166	268,716	84,568	795,449
Corporate Allocation	277,728	168,782	53,118	499,628
Net Income	54,458	33,095	10,415	97,969
Total Cost of Service	5,602,586	1,573,377	1,301,715	8,477,678

Cooperative	Demand	Energy	Customer	Total
Cost of Gas	6,532	734	0	7,266
Other Income	0	0	-5	-5
Operating & Maintenance Expenses	1,526	22	1,792	3,340
Depreciation & Amortization	500	2	649	1,152
Capital & Other Taxes	782	220	407	1,408
Finance Expense	403	559	254	1,216
Corporate Allocation	253	351	160	764
Net Income	50	69	31	150
Total Cost of Service	10,045	1,957	3,289	15,290

Main Line	Demand	Energy	Customer	Total
Cost of Gas	553,585	520,631	0	1,074,216
Other Income	0	0	-331	-331
Operating & Maintenance Expenses	460,185	3,330	100,583	564,099
Depreciation & Amortization	175,434	245	68,680	244,359
Capital & Other Taxes	261,719	26,605	17,385	305,708
Finance Expense	133,269	67,711	22,613	223,593
Corporate Allocation	83,707	42,530	14,203	140,440
Net Income	16,414	8,339	2,785	27,538
Total Cost of Service	1,684,313	669,391	225,918	2,579,622

Special Contract	Demand	Energy	Customer	Total
Cost of Gas	29,768	161,111	0	190,878
Other Income	0	0	-175	-175
Operating & Maintenance Expenses	576,384	149	73,871	650,404
Depreciation & Amortization	-13,654	-15	20,704	7,035
Capital & Other Taxes	502,533	74	12,001	514,608
Finance Expense	233,801	182	7,519	241,502
Corporate Allocation	146,852	115	4,723	151,689
Net Income	28,795	22	926	29,744
Total Cost of Service	1,504,479	161,637	119,569	1,785,685

Power Station	Demand	Energy	Customer	Total
Cost of Gas	7,322	316,467	0	323,789
Other Income	0	0	-407	-407
Operating & Maintenance Expenses	141,776	293	62,031	204,099
Depreciation & Amortization	-62,372	-30	83,406	21,004
Capital & Other Taxes	123,502	144	62,684	186,330
Finance Expense	57,233	358	39,890	97,481
Corporate Allocation	35,948	225	25,055	61,229
Net Income	7,049	44	4,913	12,006
Total Cost of Service	310,458	317,502	277,572	905,532

Interruptible	Demand	Energy	Customer	Total
Cost of Gas	891,364	928,176	0	1,819,540
Other Income	0	0	-841	-841
Operating & Maintenance Expenses	359,549	11,200	377,398	748,146
Depreciation & Amortization	176,400	981	82,562	259,943
Capital & Other Taxes	280,128	82,976	53,165	416,269
Finance Expense	165,508	211,150	36,143	412,802
Corporate Allocation	103,957	132,625	22,702	259,284
Net Income	20,384	26,006	4,451	50,841
Total Cost of Service	1,997,291	1,393,112	575,580	3,965,983

Primary Gas	Demand	Energy	Customer	Total
Cost of Gas	0	333,046,453	0	333,046,453
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	804,522	0	804,522
Depreciation & Amortization	0	77,874	0	77,874
Capital & Other Taxes	0	160,165	0	160,165
Finance Expense	0	381,754	0	381,754
Corporate Allocation	0	239,783	0	239,783
Net Income	0	47,017	0	47,017
Total Cost of Service	0	334,757,568	0	334,757,568

Supplemental Gas - Firm	Demand	Energy	Customer	Total
Cost of Gas	0	4,221,998	0	4,221,998
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	9,551	0	9,551
Depreciation & Amortization	0	925	0	925
Capital & Other Taxes	0	2,020	0	2,020
Finance Expense	0	4,834	0	4,834
Corporate Allocation	0	3,036	0	3,036
Net Income	0	595	0	595
Total Cost of Service	0	4,242,959	0	4,242,959

Supplemental Gas - Interruptible	Demand	Energy	Customer	Total
Cost of Gas	0	7,978,629	0	7,978,629
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	18,050	0	18,050
Depreciation & Amortization	0	1,747	0	1,747
Capital & Other Taxes	0	3,817	0	3,817
Finance Expense	0	9,135	0	9,135
Corporate Allocation	0	5,738	0	5,738
Net Income	0	1,125	0	1,125
Total Cost of Service	0	8,018,242	0	8,018,242

Fixed Price Offering	Demand	Energy	Customer	Total
Cost of Gas	0	5,837,350	0	5,837,350
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	293,421	0	293,421
Depreciation & Amortization	0	136,402	0	136,402
Capital & Other Taxes	0	7,552	0	7,552
Finance Expense	0	9,574	0	9,574
Corporate Allocation	0	6,014	0	6,014
Net Income	0	1,179	0	1,179
Total Cost of Service	0	6,291,492	0	6,291,492

Unassigned	Demand	Energy	Customer	Total
Cost of Gas	0	0	0	0
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	0	0	0
Depreciation & Amortization	0	0	0	0
Capital & Other Taxes	0	0	0	0
Finance Expense	0	0	0	0
Corporate Allocation	0	0	0	0
Net Income	0	0	0	0
Total Cost of Service	0	0	0	0

Total	Demand	Energy	Customer	Total
Cost of Gas	32,965,175	362,902,976	0	395,868,151
Other Income	0	0	-2,025,790	-2,025,790
Operating & Maintenance Expenses	11,528,024	1,304,197	47,511,252	60,343,473
Depreciation & Amortization	6,194,518	233,176	24,739,792	31,167,487
Capital & Other Taxes	8,803,400	1,350,065	13,786,588	23,940,053
Finance Expense	5,128,119	3,398,538	10,578,343	19,105,000
Corporate Allocation	3,221,012	2,134,648	6,644,340	12,000,000
Net Income	631,587	418,569	1,302,844	2,353,000
Total Cost of Service	68,471,835	371,742,168	102,537,370	542,751,374

Schedule 9.2.1

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Unit Cost Component Summary
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

		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 FPO
1	REVENUE REQUIREMENTS													
2	Upstream Demand ($)	34,029,819	17,581,299	12,228,206	2,729,128	6,753	564,462	0	0	919,971	0	0	0	0
3	Upstream Commodity ($)	365,969,413	6,127,429	4,383,257	1,065,375	1,957	247,980	0	0	833,155	334,757,568	4,242,959	8,018,242	6,291,492
4	Upstream Customer ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Upstream Total ($)	399,999,232	23,708,728	16,611,463	3,794,502	8,710	812,442	0	0	1,753,127	334,757,568	4,242,959	8,018,242	6,291,492
6														
7	Downstream Demand ($)	34,442,016	16,435,923	11,117,235	2,873,459	3,292	1,119,852	1,504,479	310,458	1,077,319	0	0	0	0
8	Downstream Commodity ($)	5,772,755	2,216,738	1,587,508	508,002	0	421,411	161,637	317,502	559,957	0	0	0	0
9	Downstream Customer ($)	102,537,370	86,676,241	13,357,487	1,301,715	3,289	225,918	119,569	277,572	575,580	0	0	0	0
10	Downstream Total ($)	142,752,142	105,328,902	26,062,229	4,683,176	6,580	1,767,181	1,785,685	905,532	2,212,857	0	0	0	0
11														
12	Total (incl. gas costs)	542,751,374	129,037,630	42,673,693	8,477,678	15,290	2,579,622	1,785,685	905,532	3,965,983	334,757,568	4,242,959	8,018,242	6,291,492
13														0
14														
15	MONTHLY BILLING DETERMINANTS													
16	Upstream Demand (10^3m^3-day)	132,932	66,997	45,752	10,656	25	1,907	0	0	7,595	0	0	0	0
17	Upstream Commodity (10^3m^3)	1,440,669	684,811	492,165	129,386	270	32,455	0	0	101,583	1,104,846	26,782	30,475	16,755
18	Upstream Customer (customers)	3,176,415	3,081,798	92,937	1,128	12	36	0	0	504	0	0	0	38,004
19														
20	Downstream Demand (10^3m^3-day)	166,909	66,997	45,752	12,429	25	7,102	14,633	10,900	9,071	0	0	0	0
21	Downstream Commodity (10^3m^3)	2,064,111	684,811	492,165	156,797	270	136,184	451,570	12,117	130,196	0	0	0	0
22	Downstream Customer (customers)	3,214,599	3,118,230	94,509	1,164	12	96	12	24	552	0	0	0	0
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)	255.994	0.000	0.000	166.470	266.263	295.977	0.000	0.000	78.734	0.000	0.000	0.000	0.000
28	Upstream Commodity ($/$10^3m^3$)	254.027	34.621	33.752	15.617	7.247	7.641	0.000	0.000	11.371	302.990	158.427	263.111	375.499
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)	206.352	0.000	0.000	150.269	129.785	157.679	102.816	28.482	77.198	0.000	0.000	0.000	0.000
32	Downstream Commodity ($/$10^3m^3$)	2.797	27.238	25.814	9.654	0.000	3.094	0.358	26.203	7.197	0.000	0.000	0.000	0.000
33	Downstream Customer ($/customer)	31.897	27.797	141.336	1,118.311	274.058	2,353.314	9,964.080	11,565.492	1,042.717	0.000	0.000	0.000	0.000

Schedule 9.2.2

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Comparison of Gas Costs vs. Non-Gas Costs
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

	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 FPO
1	REVENUE REQUIREMENTS													
2	Upstream Demand ($)													
3	Gas Costs	32,766,731	16,928,732	11,774,331	2,627,830	6,502	543,510	0	0	885,825	0	0	0	0
4	Non-gas Costs	1,263,088	652,567	453,875	101,297	251	20,951	0	0	34,147	0	0	0	0
5	Total	34,029,819	17,581,299	12,228,206	2,729,128	6,753	564,462	0	0	919,971	0	0	0	0
6		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Upstream Commodity ($)													
8	Gas Costs	357,149,029	2,989,289	2,128,563	475,377	734	100,593	0	0	370,043	333,046,453	4,221,998	7,978,629	5,837,350
9	Non-gas Costs	8,820,384	3,138,140	2,254,694	589,998	1,223	147,387	0	0	463,112	1,711,115	20,961	39,612	454,142
10	Total	365,969,413	6,127,429	4,383,257	1,065,375	1,957	247,980	0	0	833,155	334,757,568	4,242,959	8,018,242	6,291,492
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	389,915,760	19,918,021	13,902,894	3,103,207	7,236	644,103	0	0	1,255,868	333,046,453	4,221,998	7,978,629	5,837,350
19	Total Non-gas Costs	10,083,472	3,790,706	2,708,569	691,295	1,473	168,338	0	0	497,259	1,711,115	20,961	39,612	454,142
20	Total Upstream Costs	399,999,232	23,708,728	16,611,463	3,794,502	8,710	812,442	0	0	1,753,127	334,757,568	4,242,959	8,018,242	6,291,492
21		0	0	0	0	0	0	0	0	0	0	0	0	0
22	Downstream Demand ($)													
23	Gas Costs	198,444	77,467	53,945	14,300	30	10,074	29,768	7,322	5,539	0	0	0	0
24	Non-gas Costs	34,243,572	16,358,457	11,063,290	2,859,159	3,262	1,109,777	1,474,711	303,136	1,071,780	0	0	0	0
25	Total	34,442,016	16,435,923	11,117,235	2,873,459	3,292	1,119,852	1,504,479	310,458	1,077,319	0	0	0	0
26														
27	Downstream Commodity ($)													
28	Gas Costs	5,753,947	2,209,516	1,582,335	506,347	0	420,038	161,111	316,467	558,133	0	0	0	0
29	Non-gas Costs	18,809	7,223	5,172	1,655	0	1,373	527	1,034	1,824	0	0	0	0
30	Total	5,772,755	2,216,738	1,587,508	508,002	0	421,411	161,637	317,502	559,957	0	0	0	0
31														
32	Downstream Customer ($)													
33	Gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Non-gas Costs	102,537,370	86,676,241	13,357,487	1,301,715	3,289	225,918	119,569	277,572	575,580	0	0	0	0
35	Total	102,537,370	86,676,241	13,357,487	1,301,715	3,289	225,918	119,569	277,572	575,580	0	0	0	0
36														
37	Downstream Total ($)													
38	Total Gas Costs	5,952,391	2,286,982	1,636,280	520,647	30	430,112	190,878	323,789	563,672	0	0	0	0
39	Total Non-gas Costs	136,799,751	103,041,920	24,425,950	4,162,529	6,551	1,337,069	1,594,806	581,743	1,649,185	0	0	0	0
40	Total Downstream Costs	142,752,142	105,328,902	26,062,229	4,683,176	6,580	1,767,181	1,785,685	905,532	2,212,857	0	0	0	0
41														
42	Grand Total Gas Costs	395,868,151	22,205,004	15,539,174	3,623,854	7,266	1,074,216	190,878	323,789	1,819,540	333,046,453	4,221,998	7,978,629	5,837,350
43	Grand Total Non-gas Costs	146,883,223	106,832,627	27,134,519	4,853,824	8,024	1,505,407	1,594,806	581,743	2,146,444	1,711,115	20,961	39,612	454,142
44	Grand Total	542,751,374	129,037,630	42,673,693	8,477,678	15,290	2,579,622	1,785,685	905,532	3,965,983	334,757,568	4,242,959	8,018,242	6,291,492
45														
46														

47 Calculation of the Primary Gas Overhead Rate: 1,711,115 (line 9, PG column)
48 1,104,846 (10^3m^3 (Schedule 9.2.1, line 17, PG column)
49 1.55 10^3m^3

Calculation of the Fixed Rate Primary Gas PC 454,142 (line 9, FPO column)
16,755 (10^3m^3 (Schedule 9.2.1, line 17, FPO column)
27.10 per 10^3m^3

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Total Functionalization By Customer Class
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

Schedule 9.2.3

		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	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Energy	353,310,261	0	0	0	0	0	0	0	0	0	0	334,757,568	4,242,959	8,018,242	6,291,492
4	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Total	353,310,261	0	0	0	0	0	0	0	0	0	0	334,757,568	4,242,959	8,018,242	6,291,492
6																
7	PIPELINE															
8	Demand	15,536,759	6,898,841	1,128,131	8,026,972	5,582,948	1,246,019	3,083	257,712	0	0	420,025	0	0	0	0
9	Energy	1,007,465	415,646	63,245	478,891	344,172	90,480	189	22,696	0	0	71,037	0	0	0	0
10	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Total	16,544,224	7,314,488	1,191,376	8,505,863	5,927,120	1,336,499	3,272	280,408	0	0	491,062	0	0	0	0
12																
13	STORAGE															
14	Demand	18,493,060	8,211,537	1,342,789	9,554,327	6,645,259	1,483,109	3,670	306,749	0	0	499,946	0	0	0	0
15	Energy	11,651,687	4,885,419	763,119	5,648,538	4,039,084	974,895	1,768	225,284	0	0	762,118	0	0	0	0
16	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Total	30,144,747	13,096,956	2,105,908	15,202,865	10,684,343	2,458,004	5,438	532,033	0	0	1,262,064	0	0	0	0
18																
19	TRANSMISSION															
20	Demand	11,773,099	4,313,084	767,442	5,080,526	3,217,254	792,174	1,622	561,644	1,504,479	310,458	304,943	0	0	0	0
21	Energy	5,772,755	1,923,985	292,753	2,216,738	1,587,508	508,002	0	421,411	161,637	317,502	559,957	0	0	0	0
22	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Total	17,545,855	6,237,069	1,060,195	7,297,264	4,804,762	1,300,176	1,622	983,055	1,666,116	627,960	864,900	0	0	0	0
24																
25	DISTRIBUTION															
26	Demand	22,668,917	9,760,225	1,595,171	11,355,397	7,899,981	2,081,285	1,670	558,208	0	0	772,377	0	0	0	0
27	Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Customer	9,284,503	8,405,587	600,959	9,006,546	272,975	3,362	2	18	0	4	1,594	0	0	0	0
29	Total	31,953,420	18,165,813	2,196,131	20,361,943	8,172,956	2,084,647	1,672	558,226	0	4	773,971	0	0	0	0
30																
31	ONSITE															
32	Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Customer	93,252,868	69,543,608	8,126,087	77,669,695	13,084,512	1,298,353	3,286	225,900	119,569	277,567	573,986	0	0	0	0
35	Total	93,252,868	69,543,608	8,126,087	77,669,695	13,084,512	1,298,353	3,286	225,900	119,569	277,567	573,986	0	0	0	0
36																
37	TOTAL SERVICE															
38	Demand	68,471,835	29,183,688	4,833,534	34,017,222	23,345,441	5,602,586	10,045	1,684,313	1,504,479	310,458	1,997,291	0	0	0	0
39	Energy	371,742,168	7,225,051	1,119,116	8,344,167	5,970,764	1,573,377	1,957	669,391	161,637	317,502	1,393,112	334,757,568	4,242,959	8,018,242	6,291,492
40	Customer	102,537,370	77,949,195	8,727,046	86,676,241	13,357,487	1,301,715	3,289	225,918	119,569	277,572	575,580	0	0	0	0
41	Total	542,751,374	114,357,934	14,679,696	129,037,630	42,673,693	8,477,678	15,290	2,579,622	1,785,685	905,532	3,965,983	334,757,568	4,242,959	8,018,242	6,291,492

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Allocation Results of Rate Base
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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	37,735		0	37,735		22,527	3,166	25,693	8,115	1,492
Other Intangible Plant	402	0		0	0		0	0	0	0	0
Sub-total	401-402	37,735		0	37,735		22,527	3,166	25,693	8,115	1,492
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	1,232,659		0	1,232,659		413,712	67,481	481,193	335,083	88,823
Land Rights	461	2,970,404		0	2,970,404		996,945	162,613	1,159,558	807,468	214,042
Structures & Improvments	463	1,002,537		0	1,002,537		336,477	54,883	391,361	272,527	72,241
Mains	465	92,081,965		0	92,081,965		30,905,099	5,040,962	35,946,061	25,031,353	6,635,272
Measuring & Reg. Equipment	467	7,082,830		0	7,082,830		2,377,182	387,745	2,764,926	1,925,380	510,377
Other Transmission Equipment	469	5,150		0	5,150		1,729	282	2,010	1,400	371
Sub-total	460-469	104,375,545		0	104,375,545		35,031,144	5,713,965	40,745,109	28,373,212	7,521,127
E. DISTRIBUTION PLANT											
Land	470	819,308		0	819,308		533,496	73,690	607,186	166,552	26,883
Land Rights	471	651,504		0	651,504		424,230	58,597	482,827	132,440	21,377
Structures & Improvements	472	1,342,407		0	1,342,407		592,816	96,913	689,729	479,786	126,298
Structures & Improvements: M & R	472.1	4,089,032		0	4,089,032		1,692,243	276,455	1,968,698	1,369,907	361,387
Services	473	207,117,471		0	207,117,471		165,254,164	22,535,596	187,789,761	18,223,849	656,294
Regulators	474	46,752,083		0	46,752,083		25,112,557	4,483,636	29,596,194	15,569,819	977,970
Regulators & Meters Installations	474.1	0		0	0		0	0	0	0	0
Mains	475	162,291,074		0	162,291,074		96,755,311	11,312,470	108,067,782	40,259,879	10,198,816
Measuring & Reg. Equipment	477	35,383,327		0	35,383,327		13,768,615	2,249,323	16,017,938	11,145,986	2,940,359
Telemetry Equipment	477.1	4,046,235		0	4,046,235		1,674,531	273,561	1,948,093	1,355,569	357,605
Meters	478	41,092,142		0	41,092,142		22,072,359	3,940,835	26,013,194	13,684,892	859,574
AMR/ERT Modules	479	89,085		0	89,085		89,085	0	89,085	0	0
Other Distribution Equipment	-	0		0	0		0	0	0	0	0
Sub-total	470-479	503,673,669		0	503,673,669		327,969,409	45,301,077	373,270,486	102,388,679	16,526,562
F. GENERAL PLANT											
Land	480	137,935		0	137,935		96,214	9,095	105,308	20,964	4,129
Structures & Improvements	482	9,212,364		0	9,212,364		6,425,884	607,423	7,033,308	1,400,160	275,768
Leasehold Improvements	482.1	1,036,790		0	1,036,790		723,190	68,361	791,552	157,579	31,036
Office Furniture & Equipment	483	988,280		0	988,280		689,353	65,163	754,516	150,206	29,584
Computer Equipment: Hardware	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	9,701,325		0	9,701,325		6,766,948	639,663	7,406,612	1,474,476	290,404
Transportation Equipment	484	1,239,187		0	1,239,187		864,368	81,707	946,075	188,340	37,094
Vehicle Conversion Kits	484.1	0		0	0		0	0	0	0	0
Heavy Work Equipment	485	678,212		0	678,212		396,279	55,648	451,927	148,943	28,573
Tools & Work Equipment	486	2,928,013		0	2,928,013		1,710,834	240,247	1,951,081	643,024	123,356
Rental Equipment: Conv. Bur.	487	0		0	0		0	0	0	0	0
Communication Equipment	488	43,106		0	43,106		30,068	2,842	32,910	6,552	1,290
Other General Equipment	489	0		0	0		0	0	0	0	0
Sub-total	480-490	25,965,213		0	25,965,213		17,703,138	1,770,151	19,473,288	4,190,244	821,233
Sub-total Plant-in-Service		634,052,162		0	634,052,162		380,726,218	52,788,359	433,514,577	134,960,249	24,870,414
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		**634,052,162**		**0**	**634,052,162**		**380,726,218**	**52,788,359**	**433,514,577**	**134,960,249**	**24,870,414**
II. ACCUMULATED DEPRECIATION											
Intangible Plant		-22,482		0	-22,482		-13,402	-1,885	-15,287	-4,812	-893
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.
2009/10 and 2010/11 General Rate Application
Allocation Results of Rate Base
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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	37,735	2	506	991	350	585	0	0	0	0
Other Intangible Plant	402	0	0	0	0	0	0	0	0	0	0
Sub-total	401-402	37,735	2	506	991	350	585	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	1,232,659	185	62,578	184,907	45,482	34,407	0	0	0	0
Land Rights	461	2,970,404	446	150,797	445,580	109,602	82,912	0	0	0	0
Structures & Improvments	463	1,002,537	150	50,895	150,387	36,991	27,984	0	0	0	0
Mains	465	92,081,965	13,820	4,674,678	13,812,888	3,397,627	2,570,266	0	0	0	0
Measuring & Reg. Equipment	467	7,082,830	1,063	359,570	1,062,470	261,341	197,702	0	0	0	0
Other Transmission Equipment	469	5,150	1	261	773	190	144	0	0	0	0
Sub-total	460-469	104,375,545	15,665	5,298,780	15,657,004	3,851,234	2,913,414	0	0	0	0
E. DISTRIBUTION PLANT											
Land	470	819,308	30	4,633	511	2,919	10,593	0	0	0	0
Land Rights	471	651,504	24	3,684	406	2,321	8,423	0	0	0	0
Structures & Improvements	472	1,342,407	0	0	0	0	46,594	0	0	0	0
Structures & Improvements: M & R	472.1	4,089,032	756	252,900	0	0	135,385	0	0	0	0
Services	473	207,117,471	0	77,958	0	0	369,610	0	0	0	0
Regulators	474	46,752,083	0	107,084	0	0	501,016	0	0	0	0
Regulators & Meters Installations	474.1	0	0	0	0	0	0	0	0	0	0
Mains	475	162,291,074	0	0	0	0	3,764,598	0	0	0	0
Measuring & Reg. Equipment	477	35,383,327	17,155	2,057,671	313,332	1,789,355	1,101,532	0	0	0	0
Telemetry Equipment	477.1	4,046,235	749	250,253	0	0	133,968	0	0	0	0
Meters	478	41,092,142	0	94,120	0	0	440,361	0	0	0	0
AMR/ERT Modules	479	89,085	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	503,673,669	18,714	2,848,304	314,250	1,794,596	6,512,079	0	0	0	0
F. GENERAL PLANT											
Land	480	137,935	8	1,289	1,487	467	1,710	1,839	22	41	671
Structures & Improvements	482	9,212,364	510	86,118	99,294	31,159	114,216	122,823	1,458	2,756	44,795
Leasehold Improvements	482.1	1,036,790	57	9,692	11,175	3,507	12,854	13,823	164	310	5,041
Office Furniture & Equipment	483	988,280	55	9,239	10,652	3,343	12,253	13,176	156	296	4,806
Computer Equipment: Hardware	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	9,701,325	537	90,689	104,564	32,813	120,278	129,342	1,536	2,902	47,173
Transportation Equipment	484	1,239,187	69	11,584	13,356	4,191	15,364	16,521	196	371	6,026
Vehicle Conversion Kits	484.1	0	0	0	0	0	0	0	0	0	0
Heavy Work Equipment	485	678,212	40	10,135	20,621	6,826	11,148	0	0	0	0
Tools & Work Equipment	486	2,928,013	175	43,754	89,024	29,470	48,129	0	0	0	0
Rental Equipment: Conv. Bur.	487	0	0	0	0	0	0	0	0	0	0
Communication Equipment	488	43,106	2	403	465	146	534	575	7	13	210
Other General Equipment	489	0	0	0	0	0	0	0	0	0	0
Sub-total	480-490	25,965,213	1,453	262,904	350,638	111,920	336,486	298,098	3,539	6,688	108,721
Sub-total Plant-in-Service		634,052,162	35,834	8,410,494	16,322,883	5,758,100	9,762,564	298,098	3,539	6,688	108,721
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		**634,052,162**	**35,834**	**8,410,494**	**16,322,883**	**5,758,100**	**9,762,564**	**298,098**	**3,539**	**6,688**	**108,721**
II. ACCUMULATED DEPRECIATION											
Intangible Plant		-22,482	-1	-325	-593	-220	-350	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.
2009/10 and 2010/11 General Rate Application
Allocation Results of Rate Base
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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		-26,418,532		0	-26,418,532		-8,866,743	-1,446,259	-10,313,001	-7,181,558	-1,903,695
Distribution Plant		-185,658,131		0	-185,658,131		-120,863,470	-16,725,568	-137,589,038	-37,401,711	-6,071,604
General Plant		-17,708,350		0	-17,708,350		-11,926,696	-1,216,791	-13,143,486	-2,969,566	-588,989
Retirement Work in Progress		0		0	0		0	0	0	0	0
Sub-total		-229,807,496		0	-229,807,496		-141,670,310	-19,390,503	-161,060,813	-47,557,647	-8,565,182
Plant Held For Future Use		0		0	0		0	0	0	0	0
Total Accumulated Depreciation		**-229,807,496**		**0**	**-229,807,496**		**-141,670,310**	**-19,390,503**	**-161,060,813**	**-47,557,647**	**-8,565,182**
III. OTHER RATE BASE											
Contributions in Aid of Construction		-50,956,494		0	-50,956,494		-19,273,546	-3,099,097	-22,372,642	-14,068,091	-3,599,740
Cash Working Capital		20,194,413		0	20,194,413		6,605,589	772,271	7,377,860	1,922,416	352,197
Security Deposits		-500,000		0	-500,000		-401,313	-28,692	-430,005	-57,350	-7,913
Gas in Storage		75,807,923		0	75,807,923		31,275,820	4,758,916	36,034,735	25,897,672	6,808,266
Investment in DSM		37,058,080		0	37,058,080		22,234,848	6,299,874	28,534,721	7,782,197	370,581
Total Other Rate Base		**81,603,922**		**0**	**81,603,922**		**40,441,397**	**8,703,271**	**49,144,669**	**21,476,844**	**3,923,390**
TOTAL RATE BASE		**485,848,588**		**0**	**485,848,588**		**279,497,305**	**42,101,128**	**321,598,433**	**108,879,446**	**20,228,623**

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Allocation Results of Rate Base
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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		-26,418,532	-3,965	-1,341,204	-3,962,799	-974,810	-737,501	0	0	0	0
Distribution Plant		-185,658,131	-8,334	-1,274,219	-137,362	-784,441	-2,391,422	0	0	0	0
General Plant		-17,708,350	-936	-162,607	-247,028	-78,942	-239,726	-198,045	-2,351	-4,443	-72,230
Retirement Work in Progress		0	0	0	0	0	0	0	0	0	0
Sub-total		-229,807,496	-13,236	-2,778,355	-4,347,782	-1,838,413	-3,368,998	-198,045	-2,351	-4,443	-72,230
Plant Held For Future Use		0	0	0	0	0	0	0	0	0	0
Total Accumulated Depreciation		**-229,807,496**	**-13,236**	**-2,778,355**	**-4,347,782**	**-1,838,413**	**-3,368,998**	**-198,045**	**-2,351**	**-4,443**	**-72,230**
III. OTHER RATE BASE											
Contributions in Aid of Construction		-50,956,494	-6,447	-2,136,779	-5,911,318	-1,475,197	-1,386,279	0	0	0	0
Cash Working Capital		20,194,413	640	113,003	77,799	34,663	148,926	9,608,116	121,742	230,064	206,988
Security Deposits		-500,000	-82	-653	-82	-163	-3,753	0	0	0	0
Gas in Storage		75,807,923	14,207	1,707,774	0	0	5,345,268	0	0	0	0
Investment in DSM		37,058,080	0	370,581	0	0	0	0	0	0	0
Total Other Rate Base		**81,603,922**	**8,319**	**53,926**	**-5,833,600**	**-1,440,697**	**4,104,162**	**9,608,116**	**121,742**	**230,064**	**206,988**
TOTAL RATE BASE		**485,848,588**	**30,917**	**5,686,064**	**6,141,501**	**2,478,990**	**10,497,728**	**9,708,169**	**122,929**	**232,309**	**243,479**

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Allocation Results of Cost of Service Elements
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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											
TCPL FS Demand - Sask Zone		220,729		0	220,729		98,011	16,027	114,038	79,316	17,702
TCPL STS Demand		1,591,290		0	1,591,290		706,586	115,544	822,130	571,811	127,618
TCPL FS Demand - SSDA (Welwyn)		9,859,237		0	9,859,237		4,377,831	715,884	5,093,715	3,542,798	790,692
TCPL FS Demand - SSDA (Welwyn) to Man Zone		7,865,053		0	7,865,053		3,492,347	571,085	4,063,432	2,826,212	630,762
TCPL FS Demand - Man Zone		1,738,049		0	1,738,049		771,752	126,201	897,952	624,547	139,388
Storage Capacity Charge		6,065,784		0	6,065,784		2,693,411	440,439	3,133,850	2,179,666	486,464
Storage Deliverability Charge		4,805,100		0	4,805,100		2,133,625	348,901	2,482,526	1,726,655	385,360
ANR Oklahoma Demand		522,334		0	522,334		231,934	37,927	269,861	187,695	41,890
ANR Louisiana Demand		1,523,565		0	1,523,565		676,514	110,627	787,140	547,475	122,187
ANR Crystal Falls to Storage Demand		1,777,913		0	1,777,913		789,453	129,095	918,548	638,872	142,585
GLGT Emerson to Crystal Falls Demand		2,160,818		0	2,160,818		959,475	156,898	1,116,373	776,464	173,294
GLGT Backhaul Demand		1,054,553		0	1,054,553		468,257	76,572	544,828	378,941	84,573
Forecast Capacity Management Revenues		-6,800,000		0	-6,800,000		-3,019,428	-493,751	-3,513,179	-2,443,498	-545,347
Sub-total		32,384,424		0	32,384,424		14,379,768	2,351,448	16,731,215	11,636,953	2,597,170
B. VARIABLE TRANSPORTATION											
TCPL FS - Sask Zone		7,690		0	7,690		3,173	483	3,655	2,627	691
TCPL FS - Flowing directly to Man Zone		41,200		0	41,200		16,998	2,586	19,584	14,075	3,700
TCPL FS - SSDA (Welwyn)		566,137		0	566,137		233,569	35,540	269,109	193,405	50,844
TCPL FS - SSDA (Welwyn) to Man Zone		348,338		0	348,338		143,713	21,867	165,580	119,000	31,284
ANR Oklahoma to Crystall Falls		20,769		0	20,769		8,877	1,429	10,306	7,326	1,583
ANR Storage Transportation		80,548		0	80,548		34,429	5,541	39,970	28,413	6,140
Storage Withdrawl Chg.		125,410		0	125,410		53,605	8,627	62,232	44,238	9,560
Storage Gas - Transportation & Delivery Cost		4,265,858		0	4,265,858		1,823,382	293,444	2,116,826	1,504,778	325,179
Compressor Fuel: TCPL SSDA		16,130		0	16,130		0	0	0	0	0
Compressor Fuel: TCPL MDA		267,265		0	267,265		0	0	0	0	0
Compressor Fuel: TCPL to SSDA (Welwyn)		943,271		0	943,271		0	0	0	0	0
Compressor Fuel: TCPL SSDA (Welwyn) to MDA		444,216		0	444,216		0	0	0	0	0
Compressor Fuel: Oklahoma		149,278		0	149,278		63,807	10,269	74,075	52,658	11,379
Compressor Fuel: Storage		459,370		0	459,370		196,351	31,600	227,951	162,043	35,017
Sub-total		7,735,482		0	7,735,482		2,577,904	411,385	2,989,289	2,128,563	475,377
C. COMMODITY COST											
Primary Direct to System		265,213,668		0	265,213,668		1,440,162	219,134	1,659,296	1,188,298	380,255
Storage Gas: Primary to System		71,650,375		0	71,650,375		389,076	59,202	448,277	321,032	102,730
Oklahoma Supply		4,140,315		0	4,140,315		18,830	2,865	21,695	15,537	4,972
Storage Gas: Supplemental Supply		0		0	0		0	0	0	0	0
Seasonal Delivered Service		8,216,051		0	8,216,051		37,367	5,686	43,052	30,832	9,866
Delivered Service		13,052		0	13,052		59	9	68	49	16
Fixed Price Offering		5,934,032		0	5,934,032		32,223	4,903	37,126	26,588	8,508
Sub-total		355,167,494		0	355,167,494		1,917,717	291,799	2,209,516	1,582,335	506,347
D. OTHER GAS COSTS											
Minell Charges		198,444		0	198,444		66,603	10,864	77,467	53,945	14,300
Load Balancing Charges		228,000		0	228,000		101,240	16,555	117,795	81,929	18,285
Baseload Volume Price Increment Charges		154,307		0	154,307		68,518	11,204	79,722	55,449	12,375
Sub-total		580,751		0	580,751		236,360	38,623	274,983	191,322	44,960
Total Cost of Gas		**395,868,151**		**0**	**395,868,151**		**19,111,748**	**3,093,255**	**22,205,004**	**15,539,174**	**3,623,854**
II. OTHER REVENUE											
Rental Income		-39,786		0	-39,786		-37,131	-2,655	-39,786	0	0
Late Payment Charge		-1,849,388		0	-1,849,388		-1,725,988	-123,400	-1,849,388	0	0
Broker Revenue		-136,616		0	-136,616		-101,882	-11,905	-113,787	-19,169	-1,902
Other		0		0	0		0	0	0	0	0
Total Other Revenue		**-2,025,790**		**0**	**-2,025,790**		**-1,865,001**	**-137,959**	**-2,002,960**	**-19,169**	**-1,902**

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Allocation Results of Cost of Service Elements
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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		220,729	44	3,661	0	0	5,967	0	0	0	0
TCPL STS Demand		1,591,290	316	26,395	0	0	43,019	0	0	0	0
TCPL FS Demand - SSDA (Welwyn)		9,859,237	1,956	163,538	0	0	266,537	0	0	0	0
TCPL FS Demand - SSDA (Welwyn) to Man Zone		7,865,053	1,561	130,460	0	0	212,626	0	0	0	0
TCPL FS Demand - Man Zone		1,738,049	345	28,829	0	0	46,987	0	0	0	0
Storage Capacity Charge		6,065,784	1,204	100,615	0	0	163,984	0	0	0	0
Storage Deliverability Charge		4,805,100	954	79,703	0	0	129,902	0	0	0	0
ANR Oklahoma Demand		522,334	104	8,664	0	0	14,121	0	0	0	0
ANR Louisiana Demand		1,523,565	302	25,272	0	0	41,188	0	0	0	0
ANR Crystal Falls to Storage Demand		1,777,913	353	29,491	0	0	48,065	0	0	0	0
GLGT Emerson to Crystal Falls Demand		2,160,818	429	35,842	0	0	58,416	0	0	0	0
GLGT Backhaul Demand		1,054,553	209	17,492	0	0	28,509	0	0	0	0
Forecast Capacity Management Revenues		-6,800,000	-1,349	-112,793	0	0	-183,833	0	0	0	0
Sub-total		32,384,424	6,426	537,169	0	0	875,489	0	0	0	0
B. VARIABLE TRANSPORTATION											
TCPL FS - Sask Zone		7,690	1	173	0	0	542	0	0	0	0
TCPL FS - Flowing directly to Man Zone		41,200	8	928	0	0	2,905	0	0	0	0
TCPL FS - SSDA (Welwyn)		566,137	106	12,754	0	0	39,919	0	0	0	0
TCPL FS - SSDA (Welwyn) to Man Zone		348,338	65	7,847	0	0	24,562	0	0	0	0
ANR Oklahoma to Crystall Falls		20,769	2	321	0	0	1,230	0	0	0	0
ANR Storage Transportation		80,548	9	1,246	0	0	4,770	0	0	0	0
Storage Withdrawl Chg.		125,410	14	1,939	0	0	7,427	0	0	0	0
Storage Gas - Transportation & Delivery Cost		4,265,858	463	65,972	0	0	252,641	0	0	0	0
Compressor Fuel: TCPL SSDA		16,130	0	0	0	0	0	16,130	0	0	0
Compressor Fuel: TCPL MDA		267,265	0	0	0	0	0	267,265	0	0	0
Compressor Fuel: TCPL to SSDA (Welwyn)		943,271	0	0	0	0	0	943,271	0	0	0
Compressor Fuel: TCPL SSDA (Welwyn) to MDA		444,216	0	0	0	0	0	444,216	0	0	0
Compressor Fuel: Oklahoma		149,278	16	2,309	0	0	8,841	0	0	0	0
Compressor Fuel: Storage		459,370	50	7,104	0	0	27,206	0	0	0	0
Sub-total		7,735,482	734	100,593	0	0	370,043	1,670,883	0	0	0
C. COMMODITY COST											
Primary Direct to System		265,213,668	0	315,439	120,990	237,660	419,145	260,892,583	0	0	0
Storage Gas: Primary to System		71,650,375	0	85,219	32,687	64,206	113,237	70,482,987	0	0	0
Oklahoma Supply		4,140,315	0	4,124	1,582	3,107	5,480	0	1,410,374	2,673,443	0
Storage Gas: Supplemental Supply		0	0	0	0	0	0	0	0	0	0
Seasonal Delivered Service		8,216,051	0	8,184	3,139	6,166	10,875	0	2,798,749	5,305,187	0
Delivered Service		13,052	0	13	5	10	17	0	12,874	0	0
Fixed Price Offering		5,934,032	0	7,058	2,707	5,318	9,378	0	0	0	5,837,350
Sub-total		355,167,494	0	420,038	161,111	316,467	558,133	331,375,570	4,221,998	7,978,629	5,837,350
D. OTHER GAS COSTS											
Minell Charges		198,444	30	10,074	29,768	7,322	5,539	0	0	0	0
Load Balancing Charges		228,000	45	3,782	0	0	6,164	0	0	0	0
Baseload Volume Price Increment Charges		154,307	31	2,560	0	0	4,172	0	0	0	0
Sub-total		580,751	106	16,416	29,768	7,322	15,875	0	0	0	0
Total Cost of Gas		**395,868,151**	**7,266**	**1,074,216**	**190,878**	**323,789**	**1,819,540**	**333,046,453**	**4,221,998**	**7,978,629**	**5,837,350**
II. OTHER REVENUE											
Rental Income		-39,786	0	0	0	0	0	0	0	0	0
Late Payment Charge		-1,849,388	0	0	0	0	0	0	0	0	0
Broker Revenue		-136,616	-5	-331	-175	-407	-841	0	0	0	0
Other		0	0	0	0	0	0	0	0	0	0
Total Other Revenue		**-2,025,790**	**-5**	**-331**	**-175**	**-407**	**-841**	**0**	**0**	**0**	**0**

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Allocation Results of Cost of Service Elements
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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		234,000		0	234,000		163,457	15,468	178,925	35,755	7,053
Insurance		62,000		0	62,000		43,309	4,098	47,407	9,473	1,869
Public Affairs		801,000		0	801,000		559,525	52,947	612,473	122,391	24,143
Sub-total		1,097,000		0	1,097,000		766,291	72,514	838,804	167,619	33,065
B. FINANCE & ADMINISTRATION											
Customer Billing		3,560,000		6,000	3,554,000		3,217,570	230,041	3,447,611	104,492	1,287
Banner System		1,108,000		0	1,108,000		1,003,114	71,718	1,074,832	32,577	401
Gas IT		325,000		0	325,000		226,697	21,429	248,126	49,396	9,729
Gas Accounting		405,000		8,000	397,000		19,166	3,102	22,268	15,584	3,634
Gas Regulatory		2,761,000		33,000	2,728,000		1,902,857	179,873	2,082,730	414,621	81,661
Gas Supply		2,985,473		93,416	2,892,057		935,636	152,506	1,088,142	758,704	181,971
Treasury		336,000		0	336,000		234,369	22,154	256,524	51,068	10,058
Sub-total		11,480,473		140,416	11,340,057		7,539,410	680,822	8,220,232	1,426,440	288,741
C. TRANSMISSION & DISTRIBUTION											
Property Taxes		67,000		0	67,000		39,998	5,621	45,620	14,408	2,650
Research & Development		60,000		0	60,000		33,837	4,213	38,051	16,252	4,161
Station Maintenance		4,967,000		580,210	4,386,790		2,699,656	332,035	3,031,692	1,263,534	323,636
System Integrity		1,665,000		0	1,665,000		835,602	107,041	942,643	427,364	110,188
System Maintenance & Support		616,000		0	616,000		309,148	39,602	348,750	158,112	40,766
System Support & Communication Systems		258,000		0	258,000		43,894	7,169	51,063	35,537	102,012
Sub-total		7,633,000		580,210	7,052,790		3,962,136	495,682	4,457,818	1,915,207	583,413
D. POWER SUPPLY											
Health, Safety, Environment		232,000		0	232,000		116,432	14,915	131,347	59,549	15,353
Sub-total		232,000		0	232,000		116,432	14,915	131,347	59,549	15,353
E. CUSTOMER SERVICE & MARKETING											
Billing Inquiries & Collections		11,071,000		2,978,947	8,092,053		8,992,153	758,149	9,750,302	1,075,056	128,067
Customer Inspections		10,799,000		2,908,865	7,890,135		9,532,309	699,361	10,231,671	367,196	44,403
Customer Relations		6,420,000		165,000	6,255,000		3,426,958	352,534	3,779,492	1,490,398	527,176
Customer Safety		2,660,000		0	2,660,000		1,699,477	121,504	1,820,981	822,999	10,026
Work Coordination		2,914,000		0	2,914,000		2,416,873	210,864	2,627,737	277,301	5,208
Distribution Maintenance		8,744,000		0	8,744,000		5,265,737	764,951	6,030,688	1,834,852	348,015
Emergency		107,000		0	107,000		85,881	6,140	92,021	12,273	1,693
Load Forecast		225,000		13,000	212,000		115,220	8,238	123,458	4,289	53,068
Meter Reading		1,873,000		0	1,873,000		1,423,338	179,900	1,603,237	254,127	9,454
Metering		4,696,000		0	4,696,000		3,450,912	246,724	3,697,636	924,413	46,280
Sub-total		49,509,000		6,065,812	43,443,188		36,408,859	3,348,364	39,757,223	7,062,902	1,173,390
F. ADJUSTMENTS TO INCOME											
Corporate Alloc. & Adj.		-713,000		0	-713,000		-497,338	-47,012	-544,350	-108,367	-21,343
Depreciation, Interest, Taxes		-8,895,000		0	-8,895,000		-6,204,514	-586,498	-6,791,012	-1,351,925	-266,267
Sub-total		-9,608,000		0	-9,608,000		-6,701,851	-633,510	-7,335,361	-1,460,291	-287,611
Total Operating & Maintenance Expenses		**60,343,473**		**6,786,439**	**53,557,034**		**42,091,276**	**3,978,788**	**46,070,064**	**9,171,425**	**1,806,352**

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Allocation Results of Cost of Service Elements
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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											
Audit		234,000	11	1,663	2,522	791	2,915	3,120	37	70	1,138
Insurance		62,000	3	441	668	210	772	827	10	19	301
Public Affairs		801,000	39	5,694	8,633	2,709	9,977	10,679	127	240	3,895
Sub-total		1,097,000	53	7,798	11,824	3,710	13,664	14,626	174	328	5,334
B. FINANCE & ADMINISTRATION											
Customer Billing		3,560,000	0	0	0	0	610	0	0	0	6,000
Banner System		1,108,000	0	0	0	0	190	0	0	0	0
Gas IT		325,000	18	3,038	3,503	1,099	4,029	4,333	51	97	1,580
Gas Accounting		405,000	7	1,077	191	325	1,825	333,999	4,234	8,001	13,854
Gas Regulatory		2,761,000	151	25,502	29,403	9,227	33,822	36,371	432	816	46,265
Gas Supply		2,985,473	407	77,004	164,196	40,388	71,670	538,811	6,128	11,580	46,473
Treasury		336,000	19	3,141	3,622	1,136	4,166	4,480	53	101	1,634
Sub-total		11,480,473	601	109,762	200,915	52,175	116,313	917,993	10,898	20,596	115,806
C. TRANSMISSION & DISTRIBUTION											
Property Taxes		67,000	4	898	1,760	622	1,039	0	0	0	0
Research & Development		60,000	0	0	0	0	1,536	0	0	0	0
Station Maintenance		4,967,000	679	226,167	0	4	121,289	0	0	0	0
System Integrity		1,665,000	90	30,598	90,412	22,239	41,465	0	0	0	0
System Maintenance & Support		616,000	33	11,320	33,450	8,228	15,341	0	0	0	0
System Support & Communication Systems		258,000	20	14,215	4,825	2,862	47,466	0	0	0	0
Sub-total		7,633,000	826	283,198	130,447	33,955	228,135	0	0	0	0
D. POWER SUPPLY											
Health, Safety, Environment		232,000	13	4,264	12,598	3,099	5,778	0	0	0	0
Sub-total		232,000	13	4,264	12,598	3,099	5,778	0	0	0	0
E. CUSTOMER SERVICE & MARKETING											
Billing Inquiries & Collections		11,071,000	1,320	10,562	1,320	2,641	60,733	0	0	0	41,000
Customer Inspections		10,799,000	110	29,648	87,088	21,461	17,424	0	0	0	0
Customer Relations		6,420,000	0	80,485	76,541	59,962	240,944	0	0	0	165,000
Customer Safety		2,660,000	103	827	103	207	4,754	0	0	0	0
Work Coordination		2,914,000	0	61	0	0	3,692	0	0	0	0
Distribution Maintenance		8,744,000	350	117,996	231,961	57,057	123,081	0	0	0	0
Emergency		107,000	17	140	17	35	803	0	0	0	0
Load Forecast		225,000	0	4,377	547	1,094	25,166	0	0	0	13,000
Meter Reading		1,873,000	0	982	123	245	4,832	0	0	0	0
Metering		4,696,000	477	3,817	477	954	21,947	0	0	0	0
Sub-total		49,509,000	2,378	248,894	398,179	143,656	503,377	0	0	0	219,000
F. ADJUSTMENTS TO INCOME											
Corporate Alloc. & Adj.		-713,000	-39	-6,665	-7,685	-2,412	-8,840	-9,506	-113	-213	-3,467
Depreciation, Interest, Taxes		-8,895,000	-492	-83,152	-95,874	-30,085	-110,281	-118,591	-1,408	-2,661	-43,252
Sub-total		-9,608,000	-532	-89,817	-103,559	-32,497	-119,121	-128,097	-1,521	-2,874	-46,719
Total Operating & Maintenance Expenses		**60,343,473**	**3,340**	**564,099**	**650,404**	**204,099**	**748,146**	**804,522**	**9,551**	**18,050**	**293,421**

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Allocation Results of Cost of Service Elements
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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
IV. DEPRECIATION & AMORTIZATION											
Depreciation Expense		18,144,318		0	18,144,318		11,369,829	1,571,142	12,940,971	3,647,998	603,193
Amortization of Cust. Contributions		-996,299		0	-996,299		-58,690	64,220	5,530	-229,517	-120,456
Depreciation: Common Assets		4,251,000		0	4,251,000		2,965,193	280,293	3,245,485	646,097	127,252
Amortization Expense (Deferreds)		1,050,416		108,000	942,416		562,615	79,068	641,683	202,668	37,272
Demand Side Management Amortization Expense (Deferred)		4,918,053		0	4,918,053		2,950,832	836,069	3,786,901	1,032,791	49,181
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		**31,167,487**		**108,000**	**31,059,487**		**21,589,778**	**2,830,792**	**24,420,570**	**5,300,038**	**696,440**
V. CAPITAL & OTHER TAXES											
Municipal Taxes		15,664,700		0	15,664,700		9,351,702	1,314,261	10,665,962	3,368,717	619,522
Payroll Tax		780,780		0	780,780		544,616	51,481	596,097	118,668	23,372
Taxes on Common Assets		218,000		0	218,000		124,676	18,901	143,577	49,357	9,221
Corporate Capital Tax		2,768,746		0	2,768,746		1,583,470	240,051	1,823,521	626,872	117,108
Business Taxes		0		0	0		0	0	0	0	0
Other		0		0	0		0	0	0	0	0
Income Taxes		4,507,827		0	4,507,827		2,578,065	390,830	2,968,895	1,020,618	190,665
Total Taxes		**23,940,053**		**0**	**23,940,053**		**14,182,529**	**2,015,524**	**16,198,053**	**5,184,233**	**959,888**
VI. FINANCE EXPENSE		**19,105,000**		**0**	**19,105,000**		**10,990,659**	**1,655,541**	**12,646,199**	**4,281,461**	**795,449**
VII. CORPORATE ALLOCATION		**12,000,000**		**0**	**12,000,000**		**6,903,319**	**1,039,858**	**7,943,177**	**2,689,219**	**499,628**
VIII. NET INCOME (LOSS)		**2,353,000**		**0**	**2,353,000**		**1,353,626**	**203,899**	**1,557,525**	**527,311**	**97,969**
COST OF SERVICE SUMMARY											
COST OF GAS		395,868,151		0	395,868,151		19,111,748	3,093,255	22,205,004	15,539,174	3,623,854
OTHER REVENUE		-2,025,790		0	-2,025,790		-1,865,001	-137,959	-2,002,960	-19,169	-1,902
OPERATING EXPENSES											
President & CEO		1,097,000		0	1,097,000		766,291	72,514	838,804	167,619	33,065
Finance & Administration		11,480,473		140,416	11,340,057		7,539,410	680,822	8,220,232	1,426,440	288,741
Transmission & Distribution		7,633,000		580,210	7,052,790		3,962,136	495,682	4,457,818	1,915,207	583,413
Power Supply		232,000		0	232,000		116,432	14,915	131,347	59,549	15,353
Customer Service & Marketing		49,509,000		6,065,812	43,443,188		36,408,859	3,348,364	39,757,223	7,062,902	1,173,390
Adjustments to Income		-9,608,000		0	-9,608,000		-6,701,851	-633,510	-7,335,361	-1,460,291	-287,611
Sub-total		60,343,473		6,786,439	53,557,034		42,091,276	3,978,788	46,070,064	9,171,425	1,806,352
DEPRECIATION & AMORTIZATION		31,167,487		108,000	31,059,487		21,589,778	2,830,792	24,420,570	5,300,038	696,440
CAPITAL & OTHER TAXES		23,940,053		0	23,940,053		14,182,529	2,015,524	16,198,053	5,184,233	959,888
FINANCE EXPENSE		19,105,000		0	19,105,000		10,990,659	1,655,541	12,646,199	4,281,461	795,449
CORPORATE ALLOCATION		12,000,000		0	12,000,000		6,903,319	1,039,858	7,943,177	2,689,219	499,628
NET INCOME		2,353,000		0	2,353,000		1,353,626	203,899	1,557,525	527,311	97,969
COST OF SERVICE		542,751,374		6,894,439	535,856,935		114,357,934	14,679,696	129,037,630	42,673,693	8,477,678

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Allocation Results of Cost of Service Elements
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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		18,144,318	1,130	220,449	310,796	149,017	241,108	21,198	252	476	7,731
Amortization of Cust. Contributions		-996,299	-267	-77,637	-374,334	-151,141	-48,478	0	0	0	0
Depreciation: Common Assets		4,251,000	235	39,739	45,819	14,378	52,704	56,676	673	1,272	20,671
Amortization Expense (Deferreds)		1,050,416	53	12,627	24,754	8,750	14,609	0	0	0	108,000
Demand Side Management Amortization Expense (Deferred)		4,918,053	0	49,181	0	0	0	0	0	0	0
Furnace Replacement Program		3,800,000	0	0	0	0	0	0	0	0	0
Ex-Franchise Depreciation & Amortization		0	0	0	0	0	0	0	0	0	0
Total Depreciation & Amortization Expenses		**31,167,487**	**1,152**	**244,359**	**7,035**	**21,004**	**259,943**	**77,874**	**925**	**1,747**	**136,402**
V. CAPITAL & OTHER TAXES											
Municipal Taxes		15,664,700	886	209,887	411,455	145,449	242,822	0	0	0	0
Payroll Tax		780,780	43	7,299	8,416	2,641	9,680	10,410	124	234	3,797
Taxes on Common Assets		218,000	14	2,575	2,756	1,112	4,764	4,356	55	104	109
Corporate Capital Tax		2,768,746	177	32,703	34,999	14,127	60,501	55,325	701	1,324	1,388
Business Taxes		0	0	0	0	0	0	0	0	0	0
Other		0	0	0	0	0	0	0	0	0	0
Income Taxes		4,507,827	288	53,244	56,982	23,001	98,502	90,075	1,141	2,155	2,259
Total Taxes		**23,940,053**	**1,408**	**305,708**	**514,608**	**186,330**	**416,269**	**160,165**	**2,020**	**3,817**	**7,552**
VI. FINANCE EXPENSE		**19,105,000**	**1,216**	**223,593**	**241,502**	**97,481**	**412,802**	**381,754**	**4,834**	**9,135**	**9,574**
VII. CORPORATE ALLOCATION		**12,000,000**	**764**	**140,440**	**151,689**	**61,229**	**259,284**	**239,783**	**3,036**	**5,738**	**6,014**
VIII. NET INCOME (LOSS)		**2,353,000**	**150**	**27,538**	**29,744**	**12,006**	**50,841**	**47,017**	**595**	**1,125**	**1,179**
COST OF SERVICE SUMMARY											
COST OF GAS		395,868,151	7,266	1,074,216	190,878	323,789	1,819,540	333,046,453	4,221,998	7,978,629	5,837,350
OTHER REVENUE		-2,025,790	-5	-331	-175	-407	-841	0	0	0	0
OPERATING EXPENSES											
President & CEO		1,097,000	53	7,798	11,824	3,710	13,664	14,626	174	328	5,334
Finance & Administration		11,480,473	601	109,762	200,915	52,175	116,313	917,993	10,898	20,596	115,806
Transmission & Distribution		7,633,000	826	283,198	130,447	33,955	228,135	0	0	0	0
Power Supply		232,000	13	4,264	12,598	3,099	5,778	0	0	0	0
Customer Service & Marketing		49,509,000	2,378	248,894	398,179	143,656	503,377	0	0	0	219,000
Adjustments to Income		-9,608,000	-532	-89,817	-103,559	-32,497	-119,121	-128,097	-1,521	-2,874	-46,719
Sub-total		60,343,473	3,340	564,099	650,404	204,099	748,146	804,522	9,551	18,050	293,421
DEPRECIATION & AMORTIZATION		31,167,487	1,152	244,359	7,035	21,004	259,943	77,874	925	1,747	136,402
CAPITAL & OTHER TAXES		23,940,053	1,408	305,708	514,608	186,330	416,269	160,165	2,020	3,817	7,552
FINANCE EXPENSE		19,105,000	1,216	223,593	241,502	97,481	412,802	381,754	4,834	9,135	9,574
CORPORATE ALLOCATION		12,000,000	764	140,440	151,689	61,229	259,284	239,783	3,036	5,738	6,014
NET INCOME		2,353,000	150	27,538	29,744	12,006	50,841	47,017	595	1,125	1,179
COST OF SERVICE		542,751,374	15,290	2,579,622	1,785,685	905,532	3,965,983	334,757,568	4,242,959	8,018,242	6,291,492

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application
Final Schedules
Reflecting Order 41/10

Schedule Number	Schedule Name
5.1.1	Fixed and Variable Transportation Unit Costs, Unit Supply Prices, and Fuel Ratios
5.1.3(a) & (b)	Purchase Cost of Gas Supplied to Load
5.1.4	Difference Between Forecasted Non-Primary Gas Costs
7.1.0	Unit Cost Summary
7.2.0	Unit Cost Summary- Existing Rates as of November 1, 2009
7.3.0	Functionalization of Gas Costs
7.4.0	Classification of Gas Costs
7.5.0	Allocation of Production Capacity Costs
7.5.1	Allocation of Production Commodity Costs
7.5.2	Allocation of Pipeline Capacity Costs
7.5.3	Allocation of Pipeline Commodity Costs
7.5.4	Allocation of Storage Capacity Costs
7.5.5	Allocation of Storage Commodity Costs
7.5.6	Allocation of Transmission Capacity Costs
7.5.7	Allocation of Transmission Commodity Costs
8.1.0	Combined Annual Impacts
8.2.0	Appendix A- Schedule of Sales and Transportation Services Rates Proposed Rates Effective May 1, 2010

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application
Fixed and Variable Transportation Unit Costs, Unit Supply Prices and Fuel Ratios
2009/10 Gas Year
Supply prices for 2009/10 Gas Year (reflecting changes as per Order 41/10)

Schedule 5.1.1
Apr 26, 2010

			Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
1	**Unit Rates for Canadian Transportation**													
2	**Unit Fixed Costs**													
3														
4	TCPL FS Demand - Man Zone	CDN$/mo	$1,851,344	$1,851,344	$2,560,575	$2,562,375	$2,560,575	$2,561,175	$2,560,575	$2,292,600	$2,292,600	$2,292,600	$2,292,600	$2,560,575
5	TCPL FS Demand - Sask Zone	CDN$/mo	$14,652	$14,652	$24,096	$24,096	$24,096	$24,096	$24,096	$24,096	$24,096	$24,096	$24,096	$24,096
6	TCPL STS Demand	CDN$/mo	$126,630	$126,630	$170,955	$170,955	$170,955	$170,955	$170,955	$170,955	$170,955	$170,955	$170,955	$170,955
7														
8														
9	**Unit Transportation Costs - $/GJ**													
10														
11	TCPL FS - Man Zone	CDN$/GJ	$0.02678	$0.02678	$0.01897	$0.01897	$0.01897	$0.01897	$0.01897	$0.01897	$0.01897	$0.01897	$0.01897	$0.01897
12	TCPL FS - Sask Zone	CDN$/GJ	$0.01347	$0.01347	$0.01027	$0.01027	$0.01027	$0.01027	$0.01027	$0.01027	$0.01027	$0.01027	$0.01027	$0.01027
13	TCPL STS Forward Haul	CDN$/GJ	$0.00462	$0.00462	$0.00330	$0.00330	$0.00330	$0.00330	$0.00330	$0.00330	$0.00330	$0.00330	$0.00330	$0.00330
14	TCPL STS Forward Haul Delivery Pressure	CDN$/GJ	$0.00278	$0.00278	$0.00402	$0.00402	$0.00402	$0.00402	$0.00402	$0.00402	$0.00402	$0.00402	$0.00402	$0.00402
15														
16	**Unit Rates for U.S. Transportation and Storage**													
17	**Fixed-Rates**													
18	ANR Storage Capacity Chg.	CDN$/mo	$538,597	$538,597	$538,597	$538,597	$538,597	$518,402	$519,188	$519,188	$519,188	$519,188	$519,188	$519,188
19	ANR Storage Deliverability Chg.	CDN$/mo	$426,011	$426,011	$426,011	$426,011	$426,011	$410,660	$410,660	$410,660	$410,660	$410,660	$410,660	$410,660
20	ANR Oklahoma Demand	CDN$/mo	$46,309	$46,309	$46,309	$46,309	$46,309	$44,640	$44,640	$44,640	$44,640	$44,640	$44,640	$44,640
21	ANR Louisianna Demand	CDN$/mo	$0	$0	$0	$0	$0	$219,705	$219,932	$219,932	$219,932	$219,932	$219,932	$219,932
22	ANR Crystal Falls to Storage Demand	CDN$/mo	$65,836	$65,836	$65,836	$65,836	$65,836	$212,763	$212,763	$212,763	$212,763	$212,763	$212,763	$212,763
23	GLGT Emerson to Crys. Falls Dmd	CDN$/mo	$0	$0	$0	$0	$0	$311,600	$311,600	$311,600	$311,600	$311,600	$311,600	$311,600
24	GLGT Backhaul Demand	CDN$/mo	$229,520	$229,520	$229,520	$229,520	$229,520	$0	$0	$0	$0	$0	$0	$0
25														
26	**Variable Transportation Rates**													
27	ANR Oklahoma to Crystall Falls	CDN$/GJ	$0.01862	$0.01862	$0.01862	$0.01862	$0.01862	$0.01795	$0.01795	$0.01795	$0.01795	$0.01795	$0.01795	$0.01795
28	ANR Louisianna to Storage	CDN$/GJ	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.01491	$0.01491	$0.01491	$0.01491	$0.01491	$0.01491	$0.01491
29	ANR Storage Trans. to and From Crystal Falls	CDN$/GJ	$0.00789	$0.00789	$0.00789	$0.00789	$0.00789	$0.00953	$0.00953	$0.00953	$0.00953	$0.00953	$0.00953	$0.00953
30	ANR Storage Injection/Withdrawal	CDN$/GJ	$0.01284	$0.01284	$0.01284	$0.01284	$0.01284	$0.01237	$0.01237	$0.01237	$0.01237	$0.01237	$0.01237	$0.01237
31	GLGT Emerson to Crystall Falls	CDN$/GJ	$0.00211	$0.00211	$0.00211	$0.00211	$0.00211	$0.00817	$0.00817	$0.00817	$0.00817	$0.00817	$0.00817	$0.00817
32														
33	**Commodity Unit Supply Prices**													
34														
35	Primary Supply Direct to System Supply	CDN$/GJ	$4.78070	$5.04138	$5.10669	$5.16718	$5.15297	$5.12669	$5.13645	$5.15996	$5.22632	$5.30407	$5.37007	$5.54554
36	Storage Gas - Primary Supply to System Supply	CDN$/GJ	$4.17655	$4.17655	$4.17655	$4.17655	$4.17655	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
37	Oklahoma Supply	CDN$/GJ	$4.54497	$4.93845	$5.23356	$5.27038	$5.23671	$4.98512	$5.04597	$5.14232	$5.24881	$5.33501	$5.39890	$5.54799
38	Storage Gas - Supplemental Supply	CDN$/GJ	$4.94079	$4.94079	$4.94079	$4.94079	$4.94079	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
39	Storage Gas - Transportation Costs	CDN$/GJ	$0.20308	$0.20308	$0.20308	$0.20308	$0.20308	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
40	Delivered Service	CDN$/GJ	$4.81851	$5.36454	$5.57022	$5.62282	$5.68122	$5.42121	$5.48206	$5.57841	$5.68490	$5.77110	$5.83499	$5.98408
41	Seasonal Delivered Service	CDN$/GJ	$4.81851	$5.36454	$5.57022									
42														
43	**Fuel Ratios - %**													
44														
45	TCPL FS - Man Zone		0.42%	0.96%	1.04%	1.05%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%	0.89%
46	- Sask Zone		0.20%	0.43%	0.47%	0.47%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%
47	TCPL STS to Emerson		0.48%	1.10%	1.19%	1.20%	1.01%	1.01%	1.01%	1.01%	1.01%	1.01%	1.01%	1.01%
48	GLGT Emerson to Crystall Falls		1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%
49	ANR Crystall Falls to Storage		0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%
50	ANR Oklahoma to Crystal Falls or Storage		2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%	2.24%
51	ANR Louisiana to Storage		2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%
52	Storage Injection		1.31%	1.31%	1.31%	1.31%	1.31%	1.31%	1.31%	1.31%	1.31%	1.31%	1.31%	1.31%
53	Storage Withdrawal		0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application
Purchase Cost of Gas Supplied to Load
2009/10 Gas Year
Supply prices for 2009/10 Gas Year (reflecting changes as per Order 41/10)

Schedule 5.1.3(a)
Apr 26, 2010

			Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total
1	**Fixed Costs**														
2															
3	TCPL Firm Service Demand - Man Zone	CDN $	$1,851,344	$1,851,344	$2,560,575	$2,562,375	$2,560,575	$2,561,175	$2,560,575	$2,292,600	$2,292,600	$2,292,600	$2,292,600	$2,560,575	**$28,238,939**
4	TCPL Firm Service Demand - Sask Zone	CDN $	$14,652	$14,652	$24,096	$24,096	$24,096	$24,096	$24,096	$24,096	$24,096	$24,096	$24,096	$24,096	**$270,261**
5	TCPL STS Demand	CDN $	$126,630	$126,630	$170,955	$170,955	$170,955	$170,955	$170,955	$170,955	$170,955	$170,955	$170,955	$170,955	**$1,962,808**
6	Storage Capacity Chg.	CDN $	$513,074	$507,834	$516,762	$510,745	$492,792	$494,177	$494,927	$494,927	$494,927	$494,927	$494,927	$494,927	**$6,004,946**
7	Storage Deliverability Chg.	CDN $	$405,824	$401,679	$408,741	$403,982	$389,781	$391,470	$391,470	$391,470	$391,470	$391,470	$391,470	$391,470	**$4,750,295**
8	ANR Oklahoma Demand	CDN $	$44,115	$43,664	$44,432	$43,914	$42,371	$42,554	$42,554	$42,554	$42,554	$42,554	$42,554	$42,554	**$516,377**
9	ANR Louisianna Demand	CDN $	$0	$0	$0	$0	$0	$209,439	$209,655	$209,655	$209,655	$209,655	$209,655	$209,655	**$1,467,370**
10	ANR Storage to and From Crystal Falls Demand	CDN $	$62,716	$62,076	$63,167	$62,432	$60,237	$202,821	$202,821	$202,821	$202,821	$202,821	$202,821	$202,821	**$1,730,374**
11	GLGT Emerson to Crys. Falls Dmd	CDN $	$0	$0	$0	$0	$0	$297,040	$297,040	$297,040	$297,040	$297,040	$297,040	$297,040	**$2,079,278**
12	GLGT Backhaul Demand	CDN $	$218,644	$216,411	$220,215	$217,651	$210,001	$0	$0	$0	$0	$0	$0	$0	**$1,082,922**
13															
14	**Total Fixed Costs**	CDN $	**$3,236,999**	**$3,224,290**	**$4,008,942**	**$3,996,150**	**$3,950,807**	**$4,393,726**	**$4,394,092**	**$4,126,117**	**$4,126,117**	**$4,126,117**	**$4,126,117**	**$4,394,092**	**$48,103,569**
15															
16	**Variable Transportation Costs**														
17															
18	TCPL Firm Service - Man Zone	CDN $	$145,533	$166,500	$117,843	$106,548	$114,238	$73,077	$46,691	$26,972	$21,852	$22,323	$29,953	$74,610	**$946,142**
19	TCPL Firm Service - Sask Zone	CDN $	$923	$1,019	$753	$691	$739	$500	$307	$211	$170	$172	$244	$526	**$6,254**
20	ANR Oklahoma to Crystall Falls	CDN $	$4,183	$4,278	$4,354	$3,886	$4,152	$0	$0	$0	$0	$0	$0	$0	**$20,853**
21	ANR Storage Transportation	CDN $	$4,704	$19,503	$25,887	$25,465	$9,554	$0	$0	$0	$0	$0	$0	$0	**$85,112**
22	Storage Withdrawl Chg.	CDN $	$7,651	$31,724	$42,109	$41,423	$15,542	$0	$0	$0	$0	$0	$0	$0	**$138,449**
23	Storage Gas - Transportation & Delivery Cost	CDN $	$127,808	$535,392	$698,374	$695,084	$270,291	$0	$0	$0	$0	$0	$0	$0	**$2,326,948**
24	Compressor Fuel - TCPL to MDA	CDN $	$82,144	$229,395	$251,621	$232,522	$210,047	$132,089	$80,967	$53,201	$43,195	$44,942	$61,726	$145,817	**$1,567,665**
25	- TCPL to SSDA	CDN $	$655	$1,640	$1,759	$1,635	$1,482	$998	$614	$424	$346	$356	$510	$1,135	**$11,555**
26	- Oklahoma	CDN $	$23,393	$25,997	$28,035	$25,203	$26,751	$0	$0	$0	$0	$0	$0	$0	**$129,380**
27	- Storage	CDN $	$15,318	$64,168	$83,701	$83,307	$32,395	$0	$0	$0	$0	$0	$0	$0	**$278,889**
28															
29	**Total Variable Transportation Costs**	CDN $	**$412,313**	**$1,079,617**	**$1,254,436**	**$1,215,766**	**$685,190**	**$206,664**	**$128,578**	**$80,808**	**$65,563**	**$67,793**	**$92,432**	**$222,088**	**$5,511,247**
30															
31	**Supply Costs**														
32															
33	Primary Supply Direct to System Supply Load	CDN $	$19,885,776	$24,276,703	$24,568,608	$22,492,897	$23,971,404	$15,090,969	$9,250,822	$6,083,592	$4,939,916	$5,138,585	$7,062,862	$16,667,737	**$179,429,871**
34	Storage Gas - Primary Supply to System Supply	CDN $	$1,646,432	$7,864,697	$10,300,632	$10,492,100	$4,013,503	$0	$0	$0	$0	$0	$0	$0	**$34,317,364**
35	Oklahoma Supply	CDN $	$1,020,941	$1,134,597	$1,223,537	$1,099,948	$1,167,487	$0	$0	$0	$0	$0	$0	$0	**$5,646,509**
36	Storage Gas - Supplemental Supply	CDN $	$378,197	$1,584,283	$2,066,562	$2,056,828	$799,820	$0	$0	$0	$0	$0	$0	$0	**$6,885,689**
37	Seasonal Delivered Service		$1,691,249	$1,929,275	$2,039,663	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$5,660,187**
38	Delivered Service	CDN $	$0	$0	$0	$0	$0	$216,978	$0	$0	$0	$0	$0	$0	**$216,978**
39															
40	**Total Supply Costs**	CDN $	**$24,622,594**	**$36,789,555**	**$40,199,001**	**$36,141,773**	**$29,952,214**	**$15,307,948**	**$9,250,822**	**$6,083,592**	**$4,939,916**	**$5,138,585**	**$7,062,862**	**$16,667,737**	**$232,156,600**
41															
42	**Other**														
43	Minell Charges	CDN $	$16,537	$16,537	$16,537	$16,537	$16,537	$16,537	$16,537	$16,537	$16,537	$16,537	$16,537	$16,537	**$198,444**
44	Load Balancing Charges	CDN $	$14,000	$11,000	$11,000	$10,000	$15,000	$45,000	$35,000	$7,000	$5,000	$5,000	$15,000	$55,000	**$228,000**
45															
46	**Total Other Costs**	CDN $	**$30,537**	**$27,537**	**$27,537**	**$26,537**	**$31,537**	**$61,537**	**$51,537**	**$23,537**	**$21,537**	**$21,537**	**$31,537**	**$71,537**	**$426,444**
47															
48	**Total Cost of Gas**	CDN $	**$28,302,444**	**$41,120,998**	**$45,489,917**	**$41,380,225**	**$34,619,748**	**$19,969,875**	**$13,825,030**	**$10,314,054**	**$9,153,134**	**$9,354,032**	**$11,312,949**	**$21,355,454**	**$286,197,861**
49	Hedging Impact (System supply)	CDN $	$3,611,245	$7,028,091	$8,818,100	$248,663	$73,600	$0	$0	$0	$0	$0	$0	$0	**$19,779,699**
50	Five Year Average Capacity Management Revenues	CDN $	($580,000)	($580,000)	($580,000)	($580,000)	($580,000)	($580,000)	($580,000)	($580,000)	($580,000)	($580,000)	($580,000)	($580,000)	**($6,960,000)**
51	**Net Cost of Gas**	CDN $	**$31,333,689**	**$47,569,089**	**$53,728,017**	**$41,048,888**	**$34,113,348**	**$19,389,875**	**$13,245,030**	**$9,734,054**	**$8,573,134**	**$8,774,032**	**$10,732,949**	**$20,775,454**	**$299,017,559**

Centra Gas Manitoba Inc. **Schedule 5.1.3(b)**
2010/11 Cost of Gas Application **Apr 26, 2010**
Purchase Cost of Gas Supplied to Load
2009/10 Gas Year
Supply prices for 2009/10 Gas Year (reflecting changes as per Order 41/10)

			Total
1	**Fixed Costs**		
2			
3	TCPL Firm Service Demand - Man Zone	CDN $	**$28,238,939**
4	TCPL Firm Service Demand - Sask Zone	CDN $	**$270,261**
5	TCPL STS Demand	CDN $	**$1,962,808**
6	Storage Capacity Chg.	CDN $	**$6,004,946**
7	Storage Deliverability Chg.	CDN $	**$4,750,295**
8	ANR Oklahoma Demand	CDN $	**$516,377**
9	ANR Louisianna Demand	CDN $	**$1,467,370**
10	ANR Storage to and From Crystal Falls Demand	CDN $	**$1,730,374**
11	GLGT Emerson to Crys. Falls Dmd	CDN $	**$2,079,278**
12	GLGT Backhaul Demand	CDN $	**$1,082,922**
13			
14	**Total Fixed Costs**	CDN $	**$48,103,569**
15			
16	**Variable Transportation Costs**		
17			
18	TCPL Firm Service - Man Zone	CDN $	**$946,142**
19	TCPL Firm Service - Sask Zone	CDN $	**$6,254**
20	ANR Oklahoma to Crystall Falls	CDN $	**$20,853**
21	ANR Storage Transportation	CDN $	**$85,112**
22	Storage Withdrawl Chg.	CDN $	**$138,449**
23	Storage Gas - Transportation & Delivery Cost	CDN $	**$2,326,948**
24	Compressor Fuel - TCPL to MDA	CDN $	**$1,567,665**
25	- TCPL to SSDA	CDN $	**$11,555**
26	- Oklahoma	CDN $	**$129,380**
27	- Storage	CDN $	**$278,889**
28			
29	**Total Variable Transportation Costs**	CDN $	**$5,511,247**
30			
31	**Supply Costs**	CDN $	
32			
33	Primary Supply Direct to System Supply Load	CDN $	**$179,429,871**
34	Storage Gas - Primary Supply to System Supply	CDN $	**$34,317,364**
35	Oklahoma Supply	CDN $	**$5,646,509**
36	Storage Gas - Supplemental Supply	CDN $	**$6,885,689**
37	Seasonal Delivered Service	CDN $	**$5,660,187**
38	Delivered Service	CDN $	**$216,978**
39			
40	**Total Supply Costs**	CDN $	**$232,156,600**
41			
42	**Other**		
43	Minell Charges	CDN $	**$198,444**
44	Load Balancing Charges	CDN $	**$228,000**
45			
46	**Total Other Costs**	CDN $	**$426,444**
47			**$0**
48	**Total Cost of Gas**	CDN $	**$286,197,861**
49	Hedging Impact (System supply)	CDN $	**$19,779,699**
50	Five Year Average Capacity Management Revenues	CDN $	**($6,960,000)**
51	**Net Cost of Gas**	CDN $	**$299,017,559**

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application
Difference Between Forecasted Non-Primary Gas Costs
2008/09 Gas Year to 2009/10 Gas Year
Supply prices for 2009/10 gas year (reflecting changes as per Order 41/10)

Schedule 5.1.4
Apr 26, 2010

		(1)	(2)	(3)
		Forecast for 2008/09	Forecast for 2009/10	Difference
1	Primary Gas	$338,883,803	$231,525,595	($107,358,208)
2	Supplemental Gas	$12,200,627	$18,164,792	$5,964,165
3	Transportation	$38,677,023	$45,303,596	$6,626,574
4	Distribution	$6,106,698	$4,023,575	($2,083,123)
5				
6				
7	**Totals**	**$395,868,151**	**$299,017,558**	**($96,850,593)**
8				
9				
10	Non-Primary Gas Cost Totals	**$56,984,348**	**$67,491,963**	**$10,507,615**
11				
12				

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Unit Cost Summary

Schedule 7.1.0
April 29, 2010

		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	Fixed Price Offering FRPGS
1	REVENUE REQUIREMENTS - GAS COSTS ONLY													
2	Upstream Demand ($)	41,371,569	21,447,064	15,124,586	3,414,574	8,169	313,748	-	-	1,063,428	-	-	-	-
3	Upstream Commodity ($)	22,096,819	1,961,094	1,406,964	305,072	496	26,970	-	-	231,433	-	12,189,044	5,975,748	-
4	Upstream Customer ($)	-												
5	Upstream Total ($)	63,468,388	23,408,158	16,531,549	3,719,645	8,665	340,718	-	-	1,294,861	-	12,189,044	5,975,748	-
6														
7	Downstream Demand ($)	198,444	77,378	54,641	14,590	29	10,317	29,738	6,495	5,255	-	-	-	-
8	Downstream Commodity ($)	3,825,131	1,468,850	1,051,911	336,611	-	279,235	107,104	210,382	371,038	-	-	-	-
9	Downstream Customer ($)	-												
10	Downstream Total ($)	4,023,575	1,546,228	1,106,552	351,202	29	289,552	136,842	216,878	376,293	-	-	-	-
11														
12	Total ($)	67,491,963	24,954,386	17,638,101	4,070,847	8,695	630,270	136,842	216,878	1,671,153	-	12,189,044	5,975,748	-
13														
14	MONTHLY BILLING DETERMINANTS													
15	Upstream Demand (10^3m^3-day)	131,806	67,407	46,543	10,146	25	794	-	-	6,891	-	-	-	-
16	Upstream Commodity (10^3m^3)	1,437,578	693,319	507,693	126,396	270	12,385	-	-	97,516	1,110,428	67,003	32,180	16,755
17	Upstream Customer (customers)	-												
18														
19	Downstream Demand (10^3m^3-day)	168,028	67,407	46,543	11,506	25	6,516	15,736	11,920	8,375	-	-	-	-
20	Downstream Commodity (10^3m^3)	2,070,189	693,319	507,693	155,358	270	134,420	440,669	12,953	125,507				
21	Downstream Customer (customers)	-												
22														
23	PERCENT IN DEMAND CHARGE		0%	0%	65%	100%	100%	100%	100%	65%	100%	100%	100%	100%
24														
25	RESULTING UNIT CHARGES													
26	Upstream Demand ($/$10^3m^3$-day)		-	-	218.764	322.102	395.009	-	-	100.304	-	-	-	-
27	Upstream Commodity ($/$10^3m^3$)		33.762	32.562	11.869	1.837	2.178	-	-	6.190	-	181.918	185.696	-
28	Upstream Customer ($/customer)													
29														
30	Downstream Demand ($/$10^3m^3$-day)		-	-	0.824	1.163	1.583	-	0.545	0.408	-	-	-	-
31	Downstream Commodity ($/$10^3m^3$)		2.230	2.180	2.200	-	2.077	0.243	16.242	2.971	-	-	-	-
32	Downstream Customer ($/customer)													

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Unit Cost Summary
Existing Rates as of November 1, 2009

Schedule 7.2.0
April 29, 2010

		System Total	Small Gen. Service	Large Gen Service	High Volume	Cooperative	Main Line	Special Contracts	Power Stations	Interruptible	Primary Gas	Firm Supplemental	Interruptible Supplemental	Fixed Price Offering
1	REVENUE REQUIREMENTS - GAS COSTS ONLY													
2	Upstream Demand ($)	32,766,731	16,953,631	11,789,398	2,611,853	6,476	540,059	0	0	865,314	0	0	0	0
3	Upstream Commodity ($)	18,265,226	2,995,591	2,132,680	472,904	731	100,047	0	0	362,646		4,221,998	7,978,629	
4	Upstream Customer ($)	-	0	0	0	0	0	0	0	0	0	0	0	0
5	Upstream Total ($)	51,031,957	19,949,222	13,922,078	3,084,756	7,207	640,107	-	-	1,227,960	-	4,221,998	7,978,629	-
6														
7	Downstream Demand ($)	198,444	77,674	54,078	14,228	30	10,024	29,670	7,305	5,436	0	0	0	0
8	Downstream Commodity ($)	5,753,947	2,209,516	1,582,335	506,347	0	420,038	161,111	316,467	558,133	0	0	0	0
9	Downstream Customer ($)	-	0	0	0	0	0	0	0	0	0	0	0	0
10	Downstream Total ($)	5,952,391	2,287,189	1,636,414	520,575	30	430,062	190,781	323,772	563,569	-	-	-	-
11														
12	Total ($)	56,984,348	22,236,411	15,558,491	3,605,332	7,237	1,070,169	190,781	323,772	1,791,528	-	4,221,998	7,978,629	-
13														
14	MONTHLY BILLING DETERMINANTS													
15	Upstream Demand (10^3m^3-day)	132,906	67,368	45,998	10,341	25	1,831	0	0	7,343	0	0	0	0
16	Upstream Commodity (10^3m^3)	2,627,294	688,613	494,811	129,070	270	32,379	0	0	99,713	1,108,867	26,903	29,914	16,755
17	Upstream Customer (customers)	3,152,800	3,058,431	92,689	1,128	12	36	0	0	504	0	0	0	38,004
18														
19	Downstream Demand (10^3m^3-day)	166,556	67,368	45,998	12,046	25	6,837	14,633	10,900	8,749	0	0	0	0
20	Downstream Commodity (10^3m^3)	2,067,970	688,613	494,811	156,414	270	135,919	451,570	12,117	128,257	0	0	0	0
21	Downstream Customer (customers)	3,190,984	3,094,863	94,261	1,164	12	96	12	24	552	0	0	0	0
22														
23	PERCENT IN DEMAND CHARGE		0%	0%	65%	100%	100%	100%	100%	65%	100%	100%	100%	100%
24														
25	RESULTING UNIT CHARGES													
26	Upstream Demand ($/$10^3m^3$-day)		-	-	164.177	255.337	294.890	-	-	76.602	-	-	-	-
27	Upstream Commodity ($/$10^3m^3$)		28.970	28.136	10.746	2.709	3.090	-	-	6.674	-	156.935	266.721	-
28	Upstream Customer ($/customer)													
29														
30	Downstream Demand ($/$10^3m^3$-day)		-	-	0.768	1.171	1.466	-	0.670	0.404	-	-	-	-
31	Downstream Commodity ($/$10^3m^3$)		3.321	3.307	3.269	-	3.090	0.357	26.118	4.367	-	-	-	-
32	Downstream Customer ($/customer)													

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Functionalization of Gas Costs

Schedule 7.3.0
April 29, 2010

1		Net	Current	Proposed	Functionalization		To be	Production	Pipeline	Storage	Transmission	Distribution	OnSite	Total
2		Change	2009/10	2010/11	Direct	Allocator	Allocated							
3														
4														
5	A. FIXED COSTS													
6	TCPL CD Demand	8,826,132	19,683,067	28,509,200	0	PIPE	28,509,200		28,509,200					28,509,200
7	TCPL STS Demand	371,518	1,591,290	1,962,808	0	PIPE	1,962,808		1,962,808					1,962,808
8	Storage Capacity/Deliverability	(115,643)	10,870,884	10,755,241	0	STOR	10,755,241			10,755,241				10,755,241
9	US Pipelines Demand	(162,862)	7,039,182	6,876,320	0	STOR	6,876,320			6,876,320				6,876,320
10	Load Balancing Charges	0	228,000	228,000	0	PIPE	228,000		228,000					228,000
11	Capacity Management Revenues	(160,000)	(6,800,000)	(6,960,000)	0	PIPE	(6,960,000)		(6,960,000)					(6,960,000)
12	Other	0	198,444	198,444	0	TRAN	198,444				198,444			198,444
13	Subtotal - FIXED COSTS	8,759,145	32,810,868	41,570,013	0		41,570,013	0	23,740,008	17,631,561	198,444	0	0	41,570,013
14														
15	B. VARIABLE TRANSPORTATION													
16	TCPL Transportation	(10,969)	963,365	952,396	0	PIPE	952,396		952,396					952,396
17	US Pipelines Transportation &Comp	(195,731)	709,965	514,234	0	STOR	514,234			514,234				514,234
18	Storage Withdrawal	(1,925,871)	4,391,269	2,465,397	0	STOR	2,465,397			2,465,397				2,465,397
19	TCPL Compressor	(91,663)	1,670,883	1,579,220	-1,579,220	PROD	0							0
20	Subtotal - VARIABLE TRANSPORTATION	(2,224,234)	7,735,482	5,511,247	(1,579,220)		3,932,028	0	952,396	2,979,631	0	0	0	3,932,028
21														
22														
23														
24	C. COMMODITY COST													
25	1 Western Canadian Supplies	(71,938,130)	271,147,700	199,209,570	-195,926,562	UFG	3,283,008				3,283,008			3,283,008
26	1 Oklahoma	6,039,946	12,369,419	18,409,365	0	UFG	18,409,365	18,164,792			244,573			18,409,365
27	Storage	(37,333,011)	71,650,375	34,317,364	-34,019,814	UFG	297,550				297,550			297,550
28	Baseload Price Increment	(154,307)	154,307	0	0	PIPE	0							0
29	Other	0			0	UFG	0							0
30	Subtotal - COMMODITY COST	(103,385,503)	355,321,802	251,936,299	(229,946,377)		21,989,922	18,164,792	0	0	3,825,131	0	0	21,989,922
31														
32	TOTAL COST OF GAS	(96,850,592)	395,868,151	299,017,559	(231,525,596)		67,491,963	18,164,792	24,692,404	20,611,192	4,023,575	0	0	67,491,963

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Classification of Gas Costs

Schedule 7.4.0
April 29, 2010

Classification

		Classification			Production		Pipeline		Storage		Transmission		Distribution		OnSite		Total	
1																		
2		$ Allocated	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	28,509,200	DEMAND	0	0	0	28,509,200	0	0	0	0	0	0	0	0	0	28,509,200	0
6	TCPL STS Demand	1,962,808	DEMAND	0	0	0	1,962,808	0	0	0	0	0	0	0	0	0	1,962,808	0
7	Storage Capacity	10,755,241	DEMAND	0	0	0	0	0	10,755,241	0	0	0	0	0	0	0	10,755,241	0
8	US Pipelines Demand	6,876,320	DEMAND	0	0	0	0	0	6,876,320	0	0	0	0	0	0	0	6,876,320	0
9	Load Balancing Charges	228,000	DEMAND	0	0	0	228,000	0	0	0	0	0	0	0	0	0	228,000	0
10	Capacity Management Revenues	-6,960,000	DEMAND	0	0	0	-6,960,000	0	0	0	0	0	0	0	0	0	-6,960,000	0
11	Other	198,444	DEMAND	0	0	0	0	0	0	0	198,444	0	0	0	0	0	198,444	0
12	Subtotal - FIXED COSTS	41,570,013		0	0	0	23,740,008	0	17,631,561	0	198,444	0	0	0	0	0	41,570,013	0
13																		
14	B. VARIABLE TRANSPORTATION																	
15	TCPL Transportation	952,396	ENERGY	0	0	0	0	952,396	0	0	0	0	0	0	0	0	0	952,396
16	US Pipelines Transportation	514,234	ENERGY	0	0	0	0	0	0	514,234	0	0	0	0	0	0	0	514,234
17	Storage Withdrawal	2,465,397	ENERGY	0	0	0	0	0	0	2,465,397	0	0	0	0	0	0	0	2,465,397
18	TCPL Compressor	0	ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Subtotal - VARIABLE TRANSPORTATION	3,932,028		0	0	0	0	952,396	0	2,979,631	0	0	0	0	0	0	0	3,932,028
20																		
21																		
22																		
23	C. COMMODITY COST																	
24	1 Western Canadian Supplies	3,283,008	ENERGY	0	0	0	0	0	0	0	0	3,283,008	0	0	0	0	0	3,283,008
25	1 Arkoma	18,409,365	ENERGY	0	0	18,164,792	0	0	0	0	0	244,573	0	0	0	0	0	18,409,365
26	Storage	297,550	ENERGY	0	0	0	0	0	0	0	0	297,550	0	0	0	0	0	297,550
27	Baseload Price Increment	0	DEMAND	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Other	0	ENERGY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Subtotal - COMMODITY COST	21,989,922		0	0	18,164,792	0	0	0	0	0	3,825,131	0	0	0	0	0	21,989,922
30																		
31	TOTAL COST OF GAS	67,491,963		0	0	18,164,792	23,740,008	952,396	17,631,561	2,979,631	198,444	3,825,131	0	0	0	0	41,570,013	25,921,950

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Allocation of Production Capacity Costs

Schedule 7.5.0
April 29, 2010

Allocation of Production Capacity Costs:

					6	8	10	12	14	16	18	20	22	24	26	28	
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																
6	TCPL CD Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	TCPL STS Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Storage Capacity	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	US Pipelines Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Load Balancing Charges	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Capacity Management Revenues	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Subtotal - FIXED COSTS	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
14																	
15	B. VARIABLE TRANSPORTATION																
16	TCPL Transportation	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	US Pipelines Transportation	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Storage Withdrawal	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	TCPL Compressor	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Subtotal - VARIABLE TRANSPORTATION	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
21																	
22																	
23																	
24	C. COMMODITY COST																
25	1 Western Canadian Supplies	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	1 Arkoma	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Storage	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Baseload Price Increment	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Subtotal - COMMODITY COST	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
31																	
32	TOTAL COST OF GAS	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Allocation of Production Commodity Costs

Schedule 7.5.1
April 29, 2010

Allocation of Production Commodity Costs:

Line		$ Allocated	Commodity Allocator	$ Direct	SGS	LGS	HVF	Co-op	Mainline	Interruptible	Special Contract	Power Stations	Primary	Supplemental Supp - Firm	Supplemental Supp - Int	Other	Total Commodity
3																	
4																	
5	A. FIXED COSTS																
6	TCPL CD Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	TCPL STS Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Storage Capacity	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	US Pipelines Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Load Balancing Charges	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Capacity Management Revenues	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Subtotal - FIXED COSTS	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
14																	
15	B. VARIABLE TRANSPORTATION																
16	TCPL Transportation	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	US Pipelines Transportation	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Storage Withdrawal	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	TCPL Compressor	0	WESTERN	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Subtotal - VARIABLE TRANSPORTATION	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
21																	
22																	
23																	
24	C. COMMODITY COST																
25	1 Western Canadian Supplies	0	WESTERN	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	1 Arkoma	17,952,418	PEAKING	212,373	0	0	0	0	0	0	0	0	0	12,189,044	5,975,748	0	18,164,792
27	Storage	0	WESTERN	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Baseload Price Increment	0	COM1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Subtotal - COMMODITY COST	17,952,418		212,373	0	0	0	0	0	0	0	0	0	12,189,044	5,975,748	0	18,164,792
31																	
32	TOTAL COST OF GAS	17,952,418		212,373	0	0	0	0	0	0	0	0	0	12,189,044	5,975,748	0	18,164,792

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Allocation of Pipeline Capacity Costs

Allocation of Pipeline Capacity Costs:

			Capacity														
1											Special	Power		Supplemental	Supplemental		Total
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																
6	TCPL CD Demand	28,509,200	PAVG	0	14,779,199	10,422,371	2,352,987	5,629	216,204	732,810	0	0	0	0	0	0	28,509,200
7	TCPL STS Demand	1,962,808	PAVG	0	1,017,522	717,562	161,999	388	14,885	50,453	0	0	0	0	0	0	1,962,808
8	Storage Capacity	0	PAVG	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	US Pipelines Demand	0	PAVG	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Load Balancing Charges	228,000	PAVG	0	118,195	83,352	18,818	45	1,729	5,861	0	0	0	0	0	0	228,000
11	Capacity Management Revenues	-6,960,000	PAVG	0	(3,608,071)	(2,544,431)	(574,439)	(1,374)	(52,782)	(178,902)	0	0	0	0	0	0	-6,960,000
12	Other	0	PAVG	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Subtotal - FIXED COSTS	23,740,008		0	12,306,845	8,678,853	1,959,365	4,688	180,036	610,221	0	0	0	0	0	0	23,740,008
14																	
15	B. VARIABLE TRANSPORTATION																
16	TCPL Transportation	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	US Pipelines Transportation	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Storage Withdrawal	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Subtotal - VARIABLE TRANSPORTATION	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
21																	
22																	
23																	
24	C. COMMODITY COST																
25	1 Western Canadian Supplies	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	1 Arkoma	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Storage	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Baseload Price Increment	0	PAVG	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Subtotal - COMMODITY COST	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
31																	
32	TOTAL COST OF GAS	23,740,008		0	12,306,845	8,678,853	1,959,365	4,688	180,036	610,221	0	0	0	0	0	0	23,740,008

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Allocation of Pipeline Commodity Costs

Schedule 7.5.3
April 29, 2010

Allocation of Pipeline Commodity Costs:

1			Commodity								Special	Power		Supplemental	Supplemental	Supplemental	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																
6	TCPL CD Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	TCPL STS Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Storage Capacity	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	US Pipelines Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Load Balancing Charges	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Capacity Management Revenues	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Subtotal - FIXED COSTS	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
14																	
15	B. VARIABLE TRANSPORTATION																
16	TCPL Transportation	952,396	COM1	0	459,324	336,347	83,737	179	8,205	64,604	0	0	0	0	0	0	952,396
17	US Pipelines Transportation	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Storage Withdrawal	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Subtotal - VARIABLE TRANSPORTATION	952,396		0	459,324	336,347	83,737	179	8,205	64,604	0	0	0	0	0	0	952,396
21																	
22																	
23																	
24	C. COMMODITY COST																
25	1 Western Canadian Supplies	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	1 Arkoma	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Storage	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Baseload Price Increment	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Subtotal - COMMODITY COST	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
31																	
32	TOTAL COST OF GAS	952,396		0	459,324	336,347	83,737	179	8,205	64,604	0	0	0	0	0	0	952,396

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Allocation of Storage Capacity Costs

Schedule 7.5.4
April 29, 2010

Allocation of Storage Capacity Costs:

Line		Capacity $ Allocated	Capacity Factor	Capacity $ Direct	SGS	LGS	HVF	Co-op	Mainline	Interruptible	Special Contract	Power Stations	Primary	Supplemental Supp - Firm	Supplemental Supp - Int	Supplemental Other	Total Capacity
3																	
4																	
5	A. FIXED COSTS																
6	TCPL CD Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	TCPL STS Demand	0	PAVG	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Storage Capacity	10,755,241	PAVG	0	5,575,528	3,931,892	887,676	2,124	81,564	276,456	0	0	0	0	0	0	10,755,241
9	US Pipelines Demand	6,876,320	PAVG	0	3,564,691	2,513,840	567,532	1,358	52,148	176,751	0	0	0	0	0	0	6,876,320
10	Load Balancing Charges	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Capacity Management Revenues	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Subtotal - FIXED COSTS	17,631,561		0	9,140,219	6,445,732	1,455,209	3,482	133,712	453,207	0	0	0	0	0	0	17,631,561
14																	
15	B. VARIABLE TRANSPORTATION																
16	TCPL Transportation	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	US Pipelines Transportation	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Storage Withdrawal	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Subtotal - VARIABLE TRANSPORTATION	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
21																	
22																	
23																	
24	C. COMMODITY COST																
25	1 Western Canadian Supplies	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	1 Arkoma	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Storage	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Baseload Price Increment	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Subtotal - COMMODITY COST	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
31																	
32	TOTAL COST OF GAS	17,631,561		0	9,140,219	6,445,732	1,455,209	3,482	133,712	453,207	0	0	0	0	0	0	17,631,561

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Allocation of Storage Commodity Costs

Schedule 7.5.5
April 29, 2010

Allocation of Storage Commodity Costs:

Line		$ Allocated	Commodity Factor	$ Direct	SGS	LGS	HVF	Co-op	Mainline	Interruptible	Special Contract	Power Stations	Primary	Supplemental Supp - Firm	Supplemental Supp - Int	Supplemental Other	Total Commodity
3																	
4																	
5	A. FIXED COSTS																
6	TCPL CD Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	TCPL STS Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Storage Capacity	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	US Pipelines Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Load Balancing Charges	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Capacity Management Revenues	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Subtotal - FIXED COSTS	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
14																	
15	B. VARIABLE TRANSPORTATION																
16	TCPL Transportation	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	US Pipelines Transportation	514,234	COMWINT	0	259,180	184,770	38,199	55	3,239	28,792	0	0	0	0	0	0	514,234
18	Storage Withdrawal	2,465,397	COMWINT	0	1,242,590	885,847	183,136	262	15,526	138,036	0	0	0	0	0	0	2,465,397
19	Other	0	COMWINT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Subtotal - VARIABLE TRANSPORTATION	2,979,631		0	1,501,770	1,070,617	221,334	317	18,765	166,828	0	0	0	0	0	0	2,979,631
21																	
22																	
23																	
24	C. COMMODITY COST																
25	1 Western Canadian Supplies	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	1 Arkoma	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Storage	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Baseload Price Increment	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Subtotal - COMMODITY COST	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
31																	
32	TOTAL COST OF GAS	2,979,631		0	1,501,770	1,070,617	221,334	317	18,765	166,828	0	0	0	0	0	0	2,979,631

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Allocation of Transmission Capacity Costs

Schedule 7.5.6
April 29, 2010

Allocation of Transmission Capacity Costs:

1			Capacity								Special	Power	Allocated	Supplemental	Supplemental	Supplemental	Total
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																
6	TCPL CD Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	TCPL STS Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Storage Capacity	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	US Pipelines Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Load Balancing Charges	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Capacity Management Revenues	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Other	198,444	PAVG-T	0	77,378	54,641	14,590	29	10,317	5,255	29,738	6,495	0	0	0	0	198,444
13	Subtotal - FIXED COSTS	198,444		0	77,378	54,641	14,590	29	10,317	5,255	29,738	6,495	0	0	0	0	198,444
14																	
15	B. VARIABLE TRANSPORTATION																
16	TCPL Transportation	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	US Pipelines Transportation	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Storage Withdrawal	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Subtotal - VARIABLE TRANSPORTATION	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
21																	
22																	
23																	
24	C. COMMODITY COST																
25	1 Western Canadian Supplies	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	1 Arkoma	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Storage	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Baseload Price Increment	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Subtotal - COMMODITY COST	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
31																	
32	TOTAL COST OF GAS	198,444		0	77,378	54,641	14,590	29	10,317	5,255	29,738	6,495	0	0	0	0	198,444

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Allocation of Transmission Commodity Costs

Schedule 7.5.7
April 29, 2010

Allocation of Transmission Commodity Costs:

Line		$ Allocated	Commodity Factor	$ Direct	SGS	LGS	HVF	Co-op	Mainline	Interruptible	Special Contract	Power Stations	Primary	Supplemental Supp - Firm	Supplemental Supp - Int	Supplemental Other	Total Commodity
3																	
4																	
5	A. FIXED COSTS																
6	TCPL CD Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	TCPL STS Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Storage Capacity	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	US Pipelines Demand	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Load Balancing Charges	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Capacity Management Revenues	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Subtotal - FIXED COSTS	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
14																	
15	B. VARIABLE TRANSPORTATION																
16	TCPL Transportation	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	US Pipelines Transportation	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Storage Withdrawal	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Subtotal - VARIABLE TRANSPORTATION	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
21																	
22																	
23																	
24	C. COMMODITY COST																
25	1 Western Canadian Supplies	3,283,008	COMUFG	0	1,260,675	902,827	288,905	0	239,660	318,452	91,924	180,565	0	0	0	0	3,283,008
26	1 Arkoma	244,573	COMUFG	0	93,916	67,258	21,522	0	17,854	23,724	6,848	13,452	0	0	0	0	244,573
27	Storage	297,550	COMUFG	0	114,259	81,826	26,184	0	21,721	28,862	8,331	16,365	0	0	0	0	297,550
28	Baseload Price Increment	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Other	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Subtotal - COMMODITY COST	3,825,131		0	1,468,850	1,051,911	336,611	0	279,235	371,038	107,104	210,382	0	0	0	0	3,825,131
31																	
32	TOTAL COST OF GAS	3,825,131		0	1,468,850	1,051,911	336,611	0	279,235	371,038	107,104	210,382	0	0	0	0	3,825,131

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Combined Annual Bill Impacts

1 February 1, 2010 Billed Rates vs. May 1, 2010 Billed Rates

Line		Load Factor	Annual Use m³	FEBRUARY 1, 2010 BILLED RATES Basic Chg	Demand	Commodity	Annual	MAY 1, 2010 BILLED RATES Basic Chg	Demand	Commodity	Annual	BILL IMPACTS $	%
8	Small General Service		1,000	$156	$0	$345	$501	$168	$0	$314	$482	($19)	-3.7%
9			1,980	$156	$0	$682	$838	$168	$0	$622	$790	($49)	-5.8%
10	*(Typical Residential Customer)*		2,533	$156	$0	$873	$1,029	$168	$0	$795	$963	($66)	-6.4%
11			2,800	$156	$0	$965	$1,121	$168	$0	$879	$1,047	($74)	-6.6%
12			3,200	$156	$0	$1,103	$1,259	$168	$0	$1,005	$1,173	($86)	-6.8%
13			3,680	$156	$0	$1,268	$1,424	$168	$0	$1,155	$1,323	($101)	-7.1%
14			11,330	$156	$0	$3,904	$4,060	$168	$0	$3,557	$3,725	($335)	-8.2%
16	Large General Service		11,331	$840	$0	$3,302	$4,142	$924	$0	$2,971	$3,895	($247)	-6.0%
17			59,488	$840	$0	$17,333	$18,173	$924	$0	$15,597	$16,521	($1,652)	-9.1%
18			679,868	$840	$0	$198,092	$198,932	$924	$0	$178,256	$179,180	($19,751)	-9.9%
20	High Volume Firm	25%	850,000	$12,486	$48,574	$199,188	$260,249	$13,420	$47,797	$180,030	$241,247	($19,002)	-7.3%
21		40%	850,000	$12,486	$30,359	$199,188	$242,033	$13,420	$29,873	$180,030	$223,323	($18,710)	-7.7%
22		40%	1,416,392	$12,486	$50,588	$331,916	$394,991	$13,420	$49,779	$299,992	$363,191	($31,800)	-8.1%
23		40%	2,832,784	$12,486	$101,177	$663,831	$777,495	$13,420	$99,559	$599,984	$712,962	($64,533)	-8.3%
24		40%	6,200,000	$12,486	$221,442	$1,452,901	$1,686,829	$13,420	$217,900	$1,313,160	$1,544,480	($142,349)	-8.4%
25		40%	12,600,000	$12,486	$450,027	$2,952,669	$3,415,183	$13,420	$442,830	$2,668,680	$3,124,929	($290,254)	-8.5%
26		75%	849,835	$12,486	$16,188	$199,149	$227,824	$13,420	$15,929	$179,995	$209,344	($18,480)	-8.1%
27		75%	1,416,392	$12,486	$26,981	$331,916	$371,383	$13,420	$26,549	$299,992	$339,961	($31,422)	-8.5%
28		75%	2,832,784	$12,486	$53,961	$663,831	$730,279	$13,420	$53,098	$599,984	$666,501	($63,777)	-8.7%
29		75%	6,200,000	$12,486	$118,102	$1,452,901	$1,583,490	$13,420	$116,213	$1,313,160	$1,442,793	($140,696)	-8.9%
30		75%	12,600,000	$12,486	$240,015	$2,952,669	$3,205,170	$13,420	$236,176	$2,668,680	$2,918,276	($286,895)	-9.0%
32	Co-op	35%	250,000	$3,603	$9,360	$55,198	$68,161	$3,289	$10,845	$47,675	$61,808	($6,353)	-9.3%
33		35%	350,000	$3,603	$13,105	$77,277	$93,985	$3,289	$15,182	$66,745	$85,216	($8,768)	-9.3%
34		35%	500,000	$3,603	$18,721	$110,396	$132,720	$3,289	$21,689	$95,350	$120,328	($12,392)	-9.3%
36	Mainline Firm	40%	2,832,784	$17,943	$129,054	$640,522	$787,518	$28,240	$122,749	$574,772	$725,760	($61,758)	-7.8%
37		40%	14,163,920	$17,943	$645,270	$3,202,609	$3,865,822	$28,240	$613,744	$2,873,859	$3,515,843	($349,979)	-9.1%
38		40%	28,327,840	$17,943	$1,290,540	$6,405,219	$7,713,702	$28,240	$1,227,488	$5,747,719	$7,003,446	($710,255)	-9.2%
39		75%	2,832,784	$17,943	$68,829	$640,522	$727,293	$28,240	$65,466	$574,772	$668,478	($58,816)	-8.1%
40		75%	14,163,920	$17,943	$344,144	$3,202,609	$3,564,696	$28,240	$327,330	$2,873,859	$3,229,429	($335,267)	-9.4%
41		75%	28,327,840	$17,943	$688,288	$6,405,219	$7,111,449	$28,240	$654,660	$5,747,719	$6,430,619	($680,831)	-9.6%
42		75%	41,000,000	$17,943	$996,187	$9,270,526	$10,284,655	$28,240	$947,516	$8,318,900	$9,294,655	($990,000)	-9.6%
44	Special Contract	94%	451,570,000	$1,550,079	$0	$161,762	$1,711,841	$1,624,018	$0	$90,314	$1,610,606	($101,235)	-5.9%
46	Power Stations	5%	12,117,000	$304,393	$122,973	$272,633	$699,999	$277,572	$237,371	-$126,350	$388,592	($311,407)	-44.5%
48	Interruptible Sales	25%	849,835	$12,346	$27,185	$214,648	$254,179	$12,513	$22,888	$173,961	$209,362	($44,817)	-17.6%
49		40%	2,832,784	$12,346	$56,635	$715,494	$784,475	$12,513	$47,684	$579,871	$640,067	($144,408)	-18.4%
50		40%	14,163,920	$12,346	$283,177	$3,577,469	$3,872,992	$12,513	$238,420	$2,899,354	$3,150,287	($722,705)	-18.7%
51		75%	849,835	$12,346	$9,062	$214,648	$236,056	$12,513	$7,629	$173,961	$194,103	($41,953)	-17.8%
52		75%	2,832,784	$12,346	$30,206	$715,494	$758,045	$12,513	$25,431	$579,871	$617,815	($140,231)	-18.5%
53		75%	14,163,920	$12,346	$151,028	$3,577,469	$3,740,843	$12,513	$127,157	$2,899,354	$3,039,024	($701,819)	-18.8%

Firm Billing percentages: 95% Primary Gas, 5% Supplemental Gas
Interruptible Billing percentages: 67% Primary Gas, 33% Supplemental Gas

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Combined Annual Bill Impacts

1	**February 1, 2010 Base Rates vs. May 1, 2010 Base Rates**												
2													
3						**FEBRUARY 1, 2010 BASE RATES**				**MAY 1, 2010 BASE RATES**		**BASE IMPACTS**	
4													
5		Load	Annual Use	Basic Chg	Demand	Commodity	Annual	Basic Chg	Demand	Commodity	Annual	$	%
6		Factor	m³										
7													
8	Small General Service		1,000	$156	$0	$334	$490	$168	$0	$315	$483	($7)	-1.3%
9			1,980	$156	$0	$660	$816	$168	$0	$624	$792	($25)	-3.0%
10	*(Typical Residential Customer)*		2,533	$156	$0	$845	$1,001	$168	$0	$798	$966	($35)	-3.5%
11			2,800	$156	$0	$934	$1,090	$168	$0	$882	$1,050	($40)	-3.7%
12			3,200	$156	$0	$1,067	$1,223	$168	$0	$1,008	$1,176	($47)	-3.9%
13			3,680	$156	$0	$1,227	$1,383	$168	$0	$1,159	$1,327	($56)	-4.1%
14			11,330	$156	$0	$3,779	$3,935	$168	$0	$3,569	$3,737	($198)	-5.0%
15													
16	Large General Service		11,331	$840	$0	$3,194	$4,034	$924	$0	$2,981	$3,905	($129)	-3.2%
17			59,488	$840	$0	$16,769	$17,609	$924	$0	$15,651	$16,575	($1,034)	-5.9%
18			679,868	$840	$0	$191,650	$192,490	$924	$0	$178,868	$179,792	($12,698)	-6.6%
19													
20	High Volume Firm	25%	850,000	$12,486	$36,285	$200,014	$248,786	$13,420	$41,963	$180,200	$235,582	($13,204)	-5.3%
21		40%	850,000	$12,486	$22,678	$200,014	$235,179	$13,420	$26,227	$180,200	$219,846	($15,333)	-6.5%
22		40%	1,416,392	$12,486	$37,790	$333,292	$383,569	$13,420	$43,702	$300,275	$357,397	($26,172)	-6.8%
23		40%	2,832,784	$12,486	$75,580	$666,585	$754,651	$13,420	$87,405	$600,550	$701,375	($53,276)	-7.1%
24		40%	6,200,000	$12,486	$165,419	$1,458,928	$1,636,833	$13,420	$191,300	$1,314,400	$1,519,119	($117,713)	-7.2%
25		40%	12,600,000	$12,486	$336,174	$2,964,917	$3,313,578	$13,420	$388,770	$2,671,200	$3,073,390	($240,188)	-7.2%
26		75%	849,835	$12,486	$12,093	$199,975	$224,555	$13,420	$13,985	$180,165	$207,570	($16,985)	-7.6%
27		75%	1,416,392	$12,486	$20,155	$333,292	$365,934	$13,420	$23,308	$300,275	$337,003	($28,931)	-7.9%
28		75%	2,832,784	$12,486	$40,309	$666,585	$719,381	$13,420	$46,616	$600,550	$660,586	($58,795)	-8.2%
29		75%	6,200,000	$12,486	$88,223	$1,458,928	$1,559,637	$13,420	$102,027	$1,314,400	$1,429,846	($129,791)	-8.3%
30		75%	12,600,000	$12,486	$179,293	$2,964,917	$3,156,697	$13,420	$207,344	$2,671,200	$2,891,964	($264,733)	-8.4%
31													
32	Co-op	35%	250,000	$3,603	$9,360	$54,423	$67,386	$3,289	$10,845	$48,275	$62,408	($4,978)	-7.4%
33		35%	350,000	$3,603	$13,105	$76,192	$92,900	$3,289	$15,182	$67,585	$86,056	($6,843)	-7.4%
34		35%	500,000	$3,603	$18,721	$108,846	$131,170	$3,289	$21,689	$96,550	$121,528	($9,642)	-7.4%
35													
36	Mainline Firm	40%	2,832,784	$17,943	$112,471	$626,266	$756,679	$28,240	$131,294	$553,809	$713,343	($43,336)	-5.7%
37		40%	14,163,920	$17,943	$562,353	$3,131,329	$3,711,625	$28,240	$656,469	$2,769,046	$3,453,755	($257,870)	-6.9%
38		40%	28,327,840	$17,943	$1,124,707	$6,262,658	$7,405,307	$28,240	$1,312,937	$5,538,093	$6,879,270	($526,037)	-7.1%
39		75%	2,832,784	$17,943	$59,984	$626,266	$704,193	$28,240	$70,023	$553,809	$652,072	($52,120)	-7.4%
40		75%	14,163,920	$17,943	$299,922	$3,131,329	$3,449,193	$28,240	$350,117	$2,769,046	$3,147,403	($301,790)	-8.7%
41		75%	28,327,840	$17,943	$599,844	$6,262,658	$6,880,444	$28,240	$700,233	$5,538,093	$6,266,566	($613,878)	-8.9%
42		75%	41,000,000	$17,943	$868,177	$9,064,191	$9,950,311	$28,240	$1,013,475	$8,015,500	$9,057,215	($893,096)	-9.0%
43													
44	Special Contract	94%	451,570,000	$1,550,079	$0	$161,762	$1,711,841	$1,624,018	$0	$90,314	$1,714,332	$2,490	0.1%
45													
46	Power Stations	5%	12,117,000	$304,393	$127,604	$318,896	$750,894	$277,572	$234,881	$197,507	$709,960	($40,934)	-5.5%
47													
48	Interruptible Sales	25%	849,835	$12,346	$18,607	$212,789	$243,742	$12,513	$20,161	$173,111	$205,785	($37,957)	-15.6%
49		40%	2,832,784	$12,346	$38,765	$709,296	$760,407	$12,513	$42,003	$577,038	$631,554	($128,854)	-16.9%
50		40%	14,163,920	$12,346	$193,824	$3,546,482	$3,752,652	$12,513	$210,014	$2,885,191	$3,107,717	($644,935)	-17.2%
51		75%	849,835	$12,346	$6,202	$212,789	$231,337	$12,513	$6,720	$173,111	$192,345	($38,993)	-16.9%
52		75%	2,832,784	$12,346	$20,675	$709,296	$742,317	$12,513	$22,402	$577,038	$611,952	($130,365)	-17.6%
53		75%	14,163,920	$12,346	$103,373	$3,546,482	$3,662,201	$12,513	$112,008	$2,885,191	$3,009,711	($652,490)	-17.8%

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability:

SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m³
HVF:	For gas delivered through one meter at annual volumes greater than 680,000 m³
CO-OP:	For gas delivered to natural gas distribution cooperatives
MLC:	For gas delivered through one meter to customers served from the Transmission system
Special Contract:	For gas delivered under the terms of a Special Contract with the Company
Power Station:	For gas delivered under the terms of a Special Contract with the Company

Rates:

		Distribution to Customers			
	Transportation to Centra	**Sales Service**	**T-Service**	**Primary Gas Supply**	**Supplemental Gas Supply[1]**
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm (HVF)	N/A	$1,118.31	$1,118.31	N/A	N/A
Cooperative (CO-OP)	N/A	$274.06	$274.06	N/A	N/A
Main Line Class (MLC)	N/A	$2,353.31	$2,353.31	N/A	N/A
Special Contract	N/A	N/A	$135,334.81	N/A	N/A
Power Station	N/A	N/A	$11,565.49	N/A	N/A
Monthly Demand Charge ($/m³/month)					
High Volume Firm Class (HVF)	$0.2250	$0.1504	$0.1504	N/A	N/A
Cooperative (CO-OP)	$0.3320	$0.1298	$0.1298	N/A	N/A
Main Line Class (MLC)	$0.4060	$0.1579	$0.1579	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0283	N/A	N/A
Commodity Volumetric Charge: ($/m³)					
Small General Class (SGC)	$0.0409	$0.0874	N/A	$0.1869	$0.1827
Large General Class (LGC)	$0.0397	$0.0367	$0.0367	$0.1869	$0.1827
High Volume Firm (HVF)	$0.0167	$0.0086	$0.0086	$0.1869	$0.1827
Cooperative (CO-OP)	$0.0063	$0.0001	$0.0001	$0.1869	$0.1827
Main Line Class (MLC)	$0.0067	$0.0021	$0.0021	$0.1869	$0.1827
Special Contract	N/A	N/A	$0.0002	N/A	N/A
Power Station	N/A	N/A	$0.0163	N/A	N/A

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after May 1, 2010.

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability: For any consumer at one location whose annual natural gas requirements equal or exceed 680,000 m³ and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:

		Distribution to Customers			
	Transportation to Centra	Sales Service	T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Interruptible Service	N/A	$1,042.72	$1,042.72	N/A	N/A
Mainline Interruptible (with firm delivery)	N/A	$2,353.31	$2,353.31	N/A	N/A
Monthly Demand Charge ($/m ^{3} /month)					
Interruptible Service	$0.1032	$0.0772	$0.0772	N/A	N/A
Mainline Interruptible (with firm delivery)	$0.1588	$0.1579	$0.1579	N/A	N/A
Commodity Volumetric Charge: ($/m ^{3})					
Interruptible Service	$0.0109	$0.0059	$0.0059	$0.1869	$0.1870
Mainline Interruptible (with firm delivery)	$0.0070	$0.0021	$0.0021	$0.1869	$0.1870
Alternate Supply Service:			Negotiated		
Gas Supply (Interruptible Sales and Mainline Interruptible)			Cost of Gas		
Delivery - Interruptible Class			$0.0084		
Delivery - Mainline Interruptible Class			$0.0073		

¹ Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to Basic Monthly Charge as described above, plus Demand charges as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after May 1, 2010.

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES PLUS RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability:

SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m³
HVF:	For gas delivered to natural gas distribution cooperatives
CO-OP:	For gas delivered through one meter at annual volumes greater than 680,000 m³
MLC:	For gas delivered through one meter to customers served from the Transmission system
Special Contract:	For gas delivered under the terms of a Special Contract with the Company
Power Station:	For gas delivered under the terms of a Special Contract with the Company

Rates:

	Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm (HVF)	N/A	$1,118.31	$1,118.31	N/A	N/A
Cooperative (CO-OP)	N/A	$274.06	$274.06	N/A	N/A
Main Line Class (MLC)	N/A	$2,353.31	$2,353.31	N/A	N/A
Special Contract	N/A	N/A	$135,334.81	N/A	N/A
Power Station	N/A	N/A	$11,565.49	N/A	N/A
Monthly Demand Charge ($/m³/month)					
High Volume Firm Class (HVF)	$0.2763	$0.1513	$0.1513	N/A	N/A
Cooperative (CO-OP)	$0.3320	$0.1298	$0.1298	N/A	N/A
Main Line Class (MLC)	$0.3681	$0.1591	$0.1591	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0286	N/A	N/A
Commodity Volumetric Charge: ($/m³)					
Small General Class (SGC)	$0.0397	$0.0899	N/A	$0.1844	$0.1827
Large General Class (LGC)	$0.0388	$0.0391	$0.0374	$0.1844	$0.1827
High Volume Firm (HVF)	$0.0159	$0.0116	$0.0099	$0.1844	$0.1827
Cooperative (CO-OP)	$0.0063	$0.0001	$0.0001	$0.1844	$0.1827
Main Line Class (MLC)	$0.0138	$0.0048	$0.0031	$0.1844	$0.1827
Special Contract	N/A	N/A	$0.0002	N/A	N/A
Power Station	N/A	N/A	$0.0163	N/A	N/A
Power Station refund			-$0.0267		

¹ Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after May 1, 2010.

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES PLUS RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability: For any consumer at one location whose annual natural gas requirements equal or exceed 680,000 m³ and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:

	Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Interruptible Service	N/A	$1,042.72	$1,042.72	N/A	N/A
Mainline Interruptible (with firm delivery)	N/A	$2,353.31	$2,353.31	N/A	N/A
Monthly Demand Charge ($/m ^{3} /month)					
Interruptible Service	$0.1271	$0.0777	$0.0777	N/A	N/A
Mainline Interruptible (with firm delivery)	$0.1827	$0.1591	$0.1591	N/A	N/A
Commodity Volumetric Charge: ($/m ^{3})					
Interruptible Service	$0.0139	$0.0056	$0.0078	$0.1844	$0.1870
Mainline Interruptible (with firm delivery)	$0.0100	$0.0048	$0.0031	$0.1844	$0.1870

Alternate Supply Service:	
Gas Supply (Interruptible Sales and Mainline Interruptible)	Negotiated Cost of Gas
Delivery - Interruptible Class	$0.0104
Delivery - Mainline Interruptible Class	$0.0083

¹ Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to Basic Monthly Charge as described above, plus Demand charges as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after May 1, 2010.

BILL INSERT

2010 05 01

Natural Gas Rates Decrease May 1, 2010

Manitoba Hydro's natural gas rates decreased on May 1, 2010 by approximately 6.4 per cent or $66 per year for a typical residential customer. For larger volume customers, decreases ranged from 6.0 per cent to 18.8 per cent depending on the rate class and level of consumption. Customers who purchase Primary Gas under fixed rate contracts will see different changes to their bills.

These decreases are the result of reductions in the price that Manitoba Hydro pays for natural gas, which more than offset increases to the Basic Monthly Charge from $13 per month to $14 per month for residential and small commercial customers and from $70 per month to $77 per month for Large General Service customers. The Basic Monthly Charge recovers a portion of costs that do not vary with consumption including 24-hour emergency response, the maintenance of pipe and the reading of customers' meters.

The Primary Gas rates decreased from 21.48¢ per cubic meter to 18.44¢ per cubic meter effective May 1, 2010. The price that Manitoba Hydro pays for natural gas is passed directly on to customers without any markup. As a result, the utility does not make any profit on the sale of Primary Gas.

Primary Gas rates are updated each quarter (February, May, August and November) according to the forecast cost of Primary Gas supplies for the next 12 months. When the market price of natural gas goes up or down, the Primary Gas rate is adjusted each quarter accordingly. Quarterly adjustments help reduce the risk of large, one-time adjustments to Manitoba Hydro's customers. Manitoba Hydro lessens the impacts of volatile natural gas prices on its customers through the use of derivative instruments, gas storage, and deferral accounts. Customers also have the option of enrolling in the Equal Payment Plan which allows for the smoothing of natural gas bills over 12 monthly installments.

For more information with respect to measures that you can take to mitigate volatility in your natural gas bill, contact Manitoba Hydro at 480-5900 in Winnipeg or 1-888-624-9376 or visit Manitoba Hydro's website at: ***www.hydro.mb.ca***.

Centra Gas Manitoba Inc. ("Centra") is a wholly-owned subsidiary of Manitoba Hydro. Centra's rates and terms of service are regulated by the PUB which has approved the rate changes that are described above. The PUB's Order approving the rate change may be accessed either through the PUB's website www.pub.gov.mb.ca. or by contacting the PUB at 400 – 330 Portage Avenue, Winnipeg, Manitoba, R3C 0C4, (204-945-2638).

Manitoba Hydro

PO Box 815 • Winnipeg Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 22nd floor 360 Portage Ave
Telephone / N° de téléphone : (204) 360-3468 • Fax / N° de télécopieur : (204) 360-6147
mmurphy@hydro.mb.ca

April 30, 2010

PUBLIC UTILITIES BOARD OF MANITOBA
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

ATTENTION: Mr. G. Gaudreau, Executive Director

Dear Mr. Gaudreau:

Re: Centra Gas Manitoba Inc. ("Centra")
2009/10 & 2010/11 General Rate Application
2010/11 Cost of Gas Application
Revised Schedules

On April 29, 2010, Centra filed the final schedules related to the 2009/10 & 2010/11 General Rate Application and the 2010/11 Cost of Gas Application. Centra has determined that a minor change to cash working capital was not reflected in the cost allocation schedules. Centra requests that the following schedules filed April 29, 2010 related to the 2009/10 & 2010/11 General Rate Application be replaced with the revised schedules attached to this letter:

- Schedule 9.2.0
- Schedule 9.2.1
- Schedule 9.2.2
- Schedule 9.2.3
- Schedule 9.2.4
- Schedule 9.2.5

Similarly, the following schedules related to the 2010/11 Cost of Gas Application should be replaced with those attached to this letter:

- Schedule 8.1.0
- Schedule 8.2.0

This correction results in a slight change to the level of the Basic Monthly Charge to the Main Line, Special Contract and Power Station classes. No other rates are impacted by this change.

Copies of this letter have been provided to the PUB advisors and all registered intervenors from Centra's 2010/11 Cost of Gas Application. If you have any questions with respect to this submission or require a paper copy, please contact the writer at 360-3468, or Greg Barnlund at 360-5243.

Yours truly,
MANITOBA HYDRO LAW DEPARTMENT
Per:

M Murphy

Marla D. Murphy
Barrister and Solicitor
Att.

cc: Mr. B. Peters, Fillmore Riley
Mr. R. Cathcart, Cathcart Advisors Inc.
Mr. B. Ryall, Energy Consultants Inc.
Registered Intervenors

Schedule 9.2.0
Revised April 30, 2010

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Summary of Allocated Costs by Customer Class
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

Cost of Service Elements

SGS	Demand	Energy	Customer	Total
Cost of Gas	17,006,199	5,198,805	0	22,205,004
Other Income	0	0	-2,002,960	-2,002,960
Operating & Maintenance Expenses	5,322,287	87,282	40,660,495	46,070,064
Depreciation & Amortization	3,394,926	8,040	21,017,604	24,420,570
Capital & Other Taxes	4,062,689	559,117	11,576,374	16,198,180
Finance Expense	2,416,092	1,422,409	8,808,025	12,646,526
Corporate Allocation	1,517,566	893,426	5,532,389	7,943,382
Net Income	297,569	175,186	1,084,809	1,557,565
Total Cost of Service	34,017,328	8,344,265	86,676,736	129,038,329

LGS	Demand	Energy	Customer	Total
Cost of Gas	11,828,276	3,710,898	0	15,539,174
Other Income	0	0	-19,169	-19,169
Operating & Maintenance Expenses	3,703,770	62,194	5,405,461	9,171,425
Depreciation & Amortization	2,045,187	5,727	3,249,123	5,300,038
Capital & Other Taxes	2,826,620	401,810	1,955,848	5,184,278
Finance Expense	1,679,732	1,022,233	1,579,608	4,281,573
Corporate Allocation	1,055,053	642,072	992,164	2,689,290
Net Income	206,878	125,900	194,547	527,325
Total Cost of Service	23,345,516	5,970,835	13,357,583	42,673,933

HVF	Demand	Energy	Customer	Total
Cost of Gas	2,642,130	981,724	0	3,623,854
Other Income	0	0	-1,902	-1,902
Operating & Maintenance Expenses	962,546	14,184	829,621	1,806,352
Depreciation & Amortization	478,097	1,279	217,064	696,440
Capital & Other Taxes	745,466	105,600	108,831	959,896
Finance Expense	442,176	268,724	84,569	795,469
Corporate Allocation	277,734	168,788	53,119	499,640
Net Income	54,459	33,096	10,416	97,971
Total Cost of Service	5,602,607	1,573,396	1,301,718	8,477,721

Cooperative	Demand	Energy	Customer	Total
Cost of Gas	6,532	734	0	7,266
Other Income	0	0	-5	-5
Operating & Maintenance Expenses	1,526	22	1,792	3,340
Depreciation & Amortization	500	2	649	1,152
Capital & Other Taxes	782	220	407	1,408
Finance Expense	403	559	254	1,216
Corporate Allocation	253	351	160	764
Net Income	50	69	31	150
Total Cost of Service	10,045	1,957	3,289	15,290

Main Line	Demand	Energy	Customer	Total
Cost of Gas	553,585	520,631	0	1,074,216
Other Income	0	0	-331	-331
Operating & Maintenance Expenses	460,185	3,330	100,583	564,099
Depreciation & Amortization	175,434	245	68,680	244,359
Capital & Other Taxes	261,720	26,606	17,385	305,711
Finance Expense	133,272	67,713	22,613	223,598
Corporate Allocation	83,709	42,531	14,204	140,444
Net Income	16,414	8,340	2,785	27,539
Total Cost of Service	1,684,320	669,395	225,919	2,579,634

Special Contract	Demand	Energy	Customer	Total
Cost of Gas	29,768	161,111	0	190,878
Other Income	0	0	-175	-175
Operating & Maintenance Expenses	576,384	149	73,871	650,404
Depreciation & Amortization	-13,654	-15	20,704	7,035
Capital & Other Taxes	502,536	73	12,001	514,611
Finance Expense	233,808	182	7,519	241,509
Corporate Allocation	146,857	114	4,723	151,694
Net Income	28,796	22	926	29,745
Total Cost of Service	1,504,494	161,637	119,569	1,785,700

Power Station	Demand	Energy	Customer	Total
Cost of Gas	7,322	316,467	0	323,789
Other Income	0	0	-407	-407
Operating & Maintenance Expenses	141,776	293	62,031	204,099
Depreciation & Amortization	-62,372	-30	83,406	21,004
Capital & Other Taxes	123,503	144	62,684	186,331
Finance Expense	57,235	358	39,891	97,484
Corporate Allocation	35,949	225	25,056	61,230
Net Income	7,049	44	4,913	12,006
Total Cost of Service	310,462	317,501	277,574	905,537

Interruptible	Demand	Energy	Customer	Total
Cost of Gas	891,364	928,176	0	1,819,540
Other Income	0	0	-841	-841
Operating & Maintenance Expenses	359,549	11,200	377,398	748,146
Depreciation & Amortization	176,400	981	82,562	259,943
Capital & Other Taxes	280,130	82,978	53,165	416,273
Finance Expense	165,512	211,157	36,144	412,813
Corporate Allocation	103,959	132,629	22,702	259,291
Net Income	20,385	26,006	4,452	50,843
Total Cost of Service	1,997,299	1,393,126	575,581	3,966,007

Primary Gas	Demand	Energy	Customer	Total
Cost of Gas	0	333,046,453	0	333,046,453
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	804,522	0	804,522
Depreciation & Amortization	0	77,874	0	77,874
Capital & Other Taxes	0	159,985	0	159,985
Finance Expense	0	381,295	0	381,295
Corporate Allocation	0	239,494	0	239,494
Net Income	0	46,961	0	46,961
Total Cost of Service	0	334,756,583	0	334,756,583

Supplemental Gas - Firm	Demand	Energy	Customer	Total
Cost of Gas	0	4,221,998	0	4,221,998
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	9,551	0	9,551
Depreciation & Amortization	0	925	0	925
Capital & Other Taxes	0	2,018	0	2,018
Finance Expense	0	4,828	0	4,828
Corporate Allocation	0	3,033	0	3,033
Net Income	0	595	0	595
Total Cost of Service	0	4,242,946	0	4,242,946

Supplemental Gas - Interruptible	Demand	Energy	Customer	Total
Cost of Gas	0	7,978,629	0	7,978,629
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	18,050	0	18,050
Depreciation & Amortization	0	1,747	0	1,747
Capital & Other Taxes	0	3,813	0	3,813
Finance Expense	0	9,124	0	9,124
Corporate Allocation	0	5,731	0	5,731
Net Income	0	1,124	0	1,124
Total Cost of Service	0	8,018,218	0	8,018,218

Fixed Price Offering	Demand	Energy	Customer	Total
Cost of Gas	0	5,837,350	0	5,837,350
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	293,421	0	293,421
Depreciation & Amortization	0	136,402	0	136,402
Capital & Other Taxes	0	7,549	0	7,549
Finance Expense	0	9,566	0	9,566
Corporate Allocation	0	6,008	0	6,008
Net Income	0	1,178	0	1,178
Total Cost of Service	0	6,291,474	0	6,291,474

Unassigned	Demand	Energy	Customer	Total
Cost of Gas	0	0	0	0
Other Income	0	0	0	0
Operating & Maintenance Expenses	0	0	0	0
Depreciation & Amortization	0	0	0	0
Capital & Other Taxes	0	0	0	0
Finance Expense	0	0	0	0
Corporate Allocation	0	0	0	0
Net Income	0	0	0	0
Total Cost of Service	0	0	0	0

Total	Demand	Energy	Customer	Total
Cost of Gas	32,965,175	362,902,976	0	395,868,151
Other Income	0	0	-2,025,790	-2,025,790
Operating & Maintenance Expenses	11,528,024	1,304,197	47,511,252	60,343,473
Depreciation & Amortization	6,194,518	233,176	24,739,792	31,167,487
Capital & Other Taxes	8,803,444	1,349,911	13,786,697	23,940,053
Finance Expense	5,128,229	3,398,148	10,578,624	19,105,000
Corporate Allocation	3,221,081	2,134,403	6,644,516	12,000,000
Net Income	631,600	418,521	1,302,879	2,353,000
Total Cost of Service	68,472,072	371,741,332	102,537,970	542,751,374

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Unit Cost Component Summary
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

Schedule 9.2.1
Revised April 30, 2010

		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 FPO
1	REVENUE REQUIREMENTS													
2	Upstream Demand ($)	34,029,719	17,581,248	12,228,171	2,729,120	6,753	564,460	0	0	919,969	0	0	0	0
3	Upstream Commodity ($)	365,968,594	6,127,533	4,383,332	1,065,395	1,957	247,985	0	0	833,171	334,756,583	4,242,946	8,018,218	6,291,474
4	Upstream Customer ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Upstream Total ($)	399,998,313	23,708,781	16,611,502	3,794,514	8,710	812,445	0	0	1,753,140	334,756,583	4,242,946	8,018,218	6,291,474
6														
7	Downstream Demand ($)	34,442,352	16,436,081	11,117,345	2,873,488	3,292	1,119,860	1,504,494	310,462	1,077,330	0	0	0	0
8	Downstream Commodity ($)	5,772,738	2,216,732	1,587,503	508,001	0	421,410	161,637	317,501	559,956	0	0	0	0
9	Downstream Customer ($)	102,537,970	86,676,736	13,357,583	1,301,718	3,289	225,919	119,569	277,574	575,581	0	0	0	0
10	Downstream Total ($)	142,753,061	105,329,549	26,062,431	4,683,207	6,580	1,767,189	1,785,700	905,537	2,212,867	0	0	0	0
11														
12	Total (incl. gas costs)	542,751,374	129,038,329	42,673,933	8,477,721	15,290	2,579,634	1,785,700	905,537	3,966,007	334,756,583	4,242,946	8,018,218	6,291,474
13														0
14														
15	MONTHLY BILLING DETERMINANTS													
16	Upstream Demand (10^3m^3-day)	132,932	66,997	45,752	10,656	25	1,907	0	0	7,595	0	0	0	0
17	Upstream Commodity (10^3m^3)	1,440,669	684,811	492,165	129,386	270	32,455	0	0	101,583	1,104,846	26,782	30,475	16,755
18	Upstream Customer (customers)	3,176,415	3,081,798	92,937	1,128	12	36	0	0	504	0	0	0	38,004
19														
20	Downstream Demand (10^3m^3-day)	166,909	66,997	45,752	12,429	25	7,102	14,633	10,900	9,071	0	0	0	0
21	Downstream Commodity (10^3m^3)	2,064,111	684,811	492,165	156,797	270	136,184	451,570	12,117	130,196	0	0	0	0
22	Downstream Customer (customers)	3,214,599	3,118,230	94,509	1,164	12	96	12	24	552	0	0	0	0
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)	255.993	0.000	0.000	166.469	266.262	295.976	0.000	0.000	78.734	0.000	0.000	0.000	0.000
28	Upstream Commodity ($/$10^3m^3$)	254.027	34.621	33.752	15.617	7.247	7.641	0.000	0.000	11.372	302.989	158.427	263.110	375.498
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)	206.354	0.000	0.000	150.271	129.786	157.680	102.817	28.483	77.199	0.000	0.000	0.000	0.000
32	Downstream Commodity ($/$10^3m^3$)	2.797	27.238	25.814	9.654	0.000	3.094	0.358	26.203	7.197	0.000	0.000	0.000	0.000
33	Downstream Customer ($/customer)	31.898	27.797	141.337	1,118.314	274.059	2,353.327	9,964.104	11,565.601	1,042.720	0.000	0.000	0.000	0.000

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Comparison of Gas Costs vs. Non-Gas Costs
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

Schedule 9.2.2
Revised April 30, 2010

	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 FPO
1	REVENUE REQUIREMENTS													
2	Upstream Demand ($)													
3	Gas Costs	32,766,731	16,928,732	11,774,331	2,627,830	6,502	543,510	0	0	885,825	0	0	0	0
4	Non-gas Costs	1,262,988	652,515	453,840	101,289	251	20,950	0	0	34,144	0	0	0	0
5	Total	34,029,719	17,581,248	12,228,171	2,729,120	6,753	564,460	0	0	919,969	0	0	0	0
6		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Upstream Commodity ($)													
8	Gas Costs	357,149,029	2,989,289	2,128,563	475,377	734	100,593	0	0	370,043	333,046,453	4,221,998	7,978,629	5,837,350
9	Non-gas Costs	8,819,565	3,138,244	2,254,769	590,018	1,223	147,392	0	0	463,128	1,710,130	20,949	39,588	454,124
10	Total	365,968,594	6,127,533	4,383,332	1,065,395	1,957	247,985	0	0	833,171	334,756,583	4,242,946	8,018,218	6,291,474
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	389,915,760	19,918,021	13,902,894	3,103,207	7,236	644,103	0	0	1,255,868	333,046,453	4,221,998	7,978,629	5,837,350
19	Total Non-gas Costs	10,082,553	3,790,759	2,708,608	691,307	1,473	168,342	0	0	497,272	1,710,130	20,949	39,588	454,124
20	Total Upstream Costs	399,998,313	23,708,781	16,611,502	3,794,514	8,710	812,445	0	0	1,753,140	334,756,583	4,242,946	8,018,218	6,291,474
21		0	0	0	0	0	0	0	0	0	0	0	0	0
22	Downstream Demand ($)													
23	Gas Costs	198,444	77,467	53,945	14,300	30	10,074	29,768	7,322	5,539	0	0	0	0
24	Non-gas Costs	34,243,908	16,358,614	11,063,401	2,859,188	3,262	1,109,785	1,474,726	303,140	1,071,791	0	0	0	0
25	Total	34,442,352	16,436,081	11,117,345	2,873,488	3,292	1,119,860	1,504,494	310,462	1,077,330	0	0	0	0
26														
27	Downstream Commodity ($)													
28	Gas Costs	5,753,947	2,209,516	1,582,335	506,347	0	420,038	161,111	316,467	558,133	0	0	0	0
29	Non-gas Costs	18,792	7,216	5,168	1,654	0	1,372	526	1,034	1,823	0	0	0	0
30	Total	5,772,738	2,216,732	1,587,503	508,001	0	421,410	161,637	317,501	559,956	0	0	0	0
31														
32	Downstream Customer ($)													
33	Gas Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Non-gas Costs	102,537,970	86,676,736	13,357,583	1,301,718	3,289	225,919	119,569	277,574	575,581	0	0	0	0
35	Total	102,537,970	86,676,736	13,357,583	1,301,718	3,289	225,919	119,569	277,574	575,581	0	0	0	0
36														
37	Downstream Total ($)													
38	Total Gas Costs	5,952,391	2,286,982	1,636,280	520,647	30	430,112	190,878	323,789	563,672	0	0	0	0
39	Total Non-gas Costs	136,800,670	103,042,566	24,426,151	4,162,560	6,551	1,337,077	1,594,822	581,748	1,649,195	0	0	0	0
40	Total Downstream Costs	142,753,061	105,329,549	26,062,431	4,683,207	6,580	1,767,189	1,785,700	905,537	2,212,867	0	0	0	0
41														
42	Grand Total Gas Costs	395,868,151	22,205,004	15,539,174	3,623,854	7,266	1,074,216	190,878	323,789	1,819,540	333,046,453	4,221,998	7,978,629	5,837,350
43	Grand Total Non-gas Costs	146,883,223	106,833,325	27,134,759	4,853,867	8,024	1,505,418	1,594,822	581,748	2,146,467	1,710,130	20,949	39,588	454,124
44	Grand Total	542,751,374	129,038,329	42,673,933	8,477,721	15,290	2,579,634	1,785,700	905,537	3,966,007	334,756,583	4,242,946	8,018,218	6,291,474
45														
46														

	Calculation of the Primary Gas Overhead Rate:			Calculation of the Fixed Rate Primary Gas PC		
47		1,710,130	(line 9, PG column)		454,124	(line 9, FPO column)
48		1,104,846	(10^3m^3 (Schedule 9.2.1, line 17, PG column)		16,755	(10^3m^3 (Schedule 9.2.1, line 17, FPO column)
49		1.55	10^3m^3		27.10	per 10^3m^3

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Total Functionalization By Customer Class
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

Schedule 9.2.3
Revised April 30, 2010

		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	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Energy	353,309,222	0	0	0	0	0	0	0	0	0	0	334,756,583	4,242,946	8,018,218	6,291,474
4	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Total	353,309,222	0	0	0	0	0	0	0	0	0	0	334,756,583	4,242,946	8,018,218	6,291,474
6																
7	PIPELINE															
8	Demand	15,536,714	6,898,821	1,128,128	8,026,949	5,582,931	1,246,015	3,083	257,712	0	0	420,024	0	0	0	0
9	Energy	1,007,462	415,645	63,244	478,890	344,171	90,480	189	22,696	0	0	71,037	0	0	0	0
10	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Total	16,544,176	7,314,466	1,191,372	8,505,838	5,927,103	1,336,495	3,272	280,407	0	0	491,061	0	0	0	0
12																
13	STORAGE															
14	Demand	18,493,006	8,211,513	1,342,785	9,554,299	6,645,239	1,483,104	3,670	306,748	0	0	499,945	0	0	0	0
15	Energy	11,651,910	4,885,511	763,133	5,648,643	4,039,160	974,915	1,768	225,289	0	0	762,134	0	0	0	0
16	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Total	30,144,915	13,097,024	2,105,918	15,202,942	10,684,399	2,458,020	5,438	532,038	0	0	1,262,079	0	0	0	0
18																
19	TRANSMISSION															
20	Demand	11,773,199	4,313,117	767,447	5,080,564	3,217,281	792,181	1,622	561,649	1,504,494	310,462	304,945	0	0	0	0
21	Energy	5,772,738	1,923,980	292,752	2,216,732	1,587,503	508,001	0	421,410	161,637	317,501	559,956	0	0	0	0
22	Customer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Total	17,545,937	6,237,096	1,060,199	7,297,295	4,804,784	1,300,182	1,622	983,059	1,666,131	627,963	864,901	0	0	0	0
24																
25	DISTRIBUTION															
26	Demand	22,669,153	9,760,329	1,595,188	11,355,517	7,900,064	2,081,307	1,670	558,211	0	0	772,385	0	0	0	0
27	Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Customer	9,284,598	8,405,673	600,965	9,006,639	272,978	3,362	2	18	0	4	1,594	0	0	0	0
29	Total	31,953,751	18,166,002	2,196,154	20,362,155	8,173,042	2,084,669	1,672	558,229	0	4	773,979	0	0	0	0
30																
31	ONSITE															
32	Demand	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Customer	93,253,372	69,543,946	8,126,151	77,670,098	13,084,605	1,298,356	3,286	225,901	119,569	277,570	573,987	0	0	0	0
35	Total	93,253,372	69,543,946	8,126,151	77,670,098	13,084,605	1,298,356	3,286	225,901	119,569	277,570	573,987	0	0	0	0
36																
37	TOTAL SERVICE															
38	Demand	68,472,072	29,183,779	4,833,549	34,017,328	23,345,516	5,602,607	10,045	1,684,320	1,504,494	310,462	1,997,299	0	0	0	0
39	Energy	371,741,332	7,225,136	1,119,129	8,344,265	5,970,835	1,573,396	1,957	669,395	161,637	317,501	1,393,126	334,756,583	4,242,946	8,018,218	6,291,474
40	Customer	102,537,970	77,949,620	8,727,117	86,676,736	13,357,583	1,301,718	3,289	225,919	119,569	277,574	575,581	0	0	0	0
41	Total	542,751,374	114,358,534	14,679,795	129,038,329	42,673,933	8,477,721	15,290	2,579,634	1,785,700	905,537	3,966,007	334,756,583	4,242,946	8,018,218	6,291,474

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Allocation Results of Rate Base
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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	37,735		0	37,735		22,527	3,166	25,693	8,115	1,492
Other Intangible Plant	402	0		0	0		0	0	0	0	0
Sub-total	401-402	37,735		0	37,735		22,527	3,166	25,693	8,115	1,492
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	1,232,659		0	1,232,659		413,712	67,481	481,193	335,083	88,823
Land Rights	461	2,970,404		0	2,970,404		996,945	162,613	1,159,558	807,468	214,042
Structures & Improvments	463	1,002,537		0	1,002,537		336,477	54,883	391,361	272,527	72,241
Mains	465	92,081,965		0	92,081,965		30,905,099	5,040,962	35,946,061	25,031,353	6,635,272
Measuring & Reg. Equipment	467	7,082,830		0	7,082,830		2,377,182	387,745	2,764,926	1,925,380	510,377
Other Transmission Equipment	469	5,150		0	5,150		1,729	282	2,010	1,400	371
Sub-total	460-469	104,375,545		0	104,375,545		35,031,144	5,713,965	40,745,109	28,373,212	7,521,127
E. DISTRIBUTION PLANT											
Land	470	819,308		0	819,308		533,496	73,690	607,186	166,552	26,883
Land Rights	471	651,504		0	651,504		424,230	58,597	482,827	132,440	21,377
Structures & Improvements	472	1,342,407		0	1,342,407		592,816	96,913	689,729	479,786	126,298
Structures & Improvements: M & R	472.1	4,089,032		0	4,089,032		1,692,243	276,455	1,968,698	1,369,907	361,387
Services	473	207,117,471		0	207,117,471		165,254,164	22,535,596	187,789,761	18,223,849	656,294
Regulators	474	46,752,083		0	46,752,083		25,112,557	4,483,636	29,596,194	15,569,819	977,970
Regulators & Meters Installations	474.1	0		0	0		0	0	0	0	0
Mains	475	162,291,074		0	162,291,074		96,755,311	11,312,470	108,067,782	40,259,879	10,198,816
Measuring & Reg. Equipment	477	35,383,327		0	35,383,327		13,768,615	2,249,323	16,017,938	11,145,986	2,940,359
Telemetry Equipment	477.1	4,046,235		0	4,046,235		1,674,531	273,561	1,948,093	1,355,569	357,605
Meters	478	41,092,142		0	41,092,142		22,072,359	3,940,835	26,013,194	13,684,892	859,574
AMR/ERT Modules	479	89,085		0	89,085		89,085	0	89,085	0	0
Other Distribution Equipment	-	0		0	0		0	0	0	0	0
Sub-total	470-479	503,673,669		0	503,673,669		327,969,409	45,301,077	373,270,486	102,388,679	16,526,562
F. GENERAL PLANT											
Land	480	137,935		0	137,935		96,214	9,095	105,308	20,964	4,129
Structures & Improvements	482	9,212,364		0	9,212,364		6,425,884	607,423	7,033,308	1,400,160	275,768
Leasehold Improvements	482.1	1,036,790		0	1,036,790		723,190	68,361	791,552	157,579	31,036
Office Furniture & Equipment	483	988,280		0	988,280		689,353	65,163	754,516	150,206	29,584
Computer Equipment: Hardware	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	9,701,325		0	9,701,325		6,766,948	639,663	7,406,612	1,474,476	290,404
Transportation Equipment	484	1,239,187		0	1,239,187		864,368	81,707	946,075	188,340	37,094
Vehicle Conversion Kits	484.1	0		0	0		0	0	0	0	0
Heavy Work Equipment	485	678,212		0	678,212		396,279	55,648	451,927	148,943	28,573
Tools & Work Equipment	486	2,928,013		0	2,928,013		1,710,834	240,247	1,951,081	643,024	123,356
Rental Equipment: Conv. Bur.	487	0		0	0		0	0	0	0	0
Communication Equipment	488	43,106		0	43,106		30,068	2,842	32,910	6,552	1,290
Other General Equipment	489	0		0	0		0	0	0	0	0
Sub-total	480-490	25,965,213		0	25,965,213		17,703,138	1,770,151	19,473,288	4,190,244	821,233
Sub-total Plant-in-Service		634,052,162		0	634,052,162		380,726,218	52,788,359	433,514,577	134,960,249	24,870,414
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		**634,052,162**		**0**	**634,052,162**		**380,726,218**	**52,788,359**	**433,514,577**	**134,960,249**	**24,870,414**
II. ACCUMULATED DEPRECIATION											
Intangible Plant		-22,482		0	-22,482		-13,402	-1,885	-15,287	-4,812	-893
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.
2009/10 and 2010/11 General Rate Application
Allocation Results of Rate Base
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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	37,735	2	506	991	350	585	0	0	0	0
Other Intangible Plant	402	0	0	0	0	0	0	0	0	0	0
Sub-total	401-402	37,735	2	506	991	350	585	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	1,232,659	185	62,578	184,907	45,482	34,407	0	0	0	0
Land Rights	461	2,970,404	446	150,797	445,580	109,602	82,912	0	0	0	0
Structures & Improvments	463	1,002,537	150	50,895	150,387	36,991	27,984	0	0	0	0
Mains	465	92,081,965	13,820	4,674,678	13,812,888	3,397,627	2,570,266	0	0	0	0
Measuring & Reg. Equipment	467	7,082,830	1,063	359,570	1,062,470	261,341	197,702	0	0	0	0
Other Transmission Equipment	469	5,150	1	261	773	190	144	0	0	0	0
Sub-total	460-469	104,375,545	15,665	5,298,780	15,657,004	3,851,234	2,913,414	0	0	0	0
E. DISTRIBUTION PLANT											
Land	470	819,308	30	4,633	511	2,919	10,593	0	0	0	0
Land Rights	471	651,504	24	3,684	406	2,321	8,423	0	0	0	0
Structures & Improvements	472	1,342,407	0	0	0	0	46,594	0	0	0	0
Structures & Improvements: M & R	472.1	4,089,032	756	252,900	0	0	135,385	0	0	0	0
Services	473	207,117,471	0	77,958	0	0	369,610	0	0	0	0
Regulators	474	46,752,083	0	107,084	0	0	501,016	0	0	0	0
Regulators & Meters Installations	474.1	0	0	0	0	0	0	0	0	0	0
Mains	475	162,291,074	0	0	0	0	3,764,598	0	0	0	0
Measuring & Reg. Equipment	477	35,383,327	17,155	2,057,671	313,332	1,789,355	1,101,532	0	0	0	0
Telemetry Equipment	477.1	4,046,235	749	250,253	0	0	133,968	0	0	0	0
Meters	478	41,092,142	0	94,120	0	0	440,361	0	0	0	0
AMR/ERT Modules	479	89,085	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	503,673,669	18,714	2,848,304	314,250	1,794,596	6,512,079	0	0	0	0
F. GENERAL PLANT											
Land	480	137,935	8	1,289	1,487	467	1,710	1,839	22	41	671
Structures & Improvements	482	9,212,364	510	86,118	99,294	31,159	114,216	122,823	1,458	2,756	44,795
Leasehold Improvements	482.1	1,036,790	57	9,692	11,175	3,507	12,854	13,823	164	310	5,041
Office Furniture & Equipment	483	988,280	55	9,239	10,652	3,343	12,253	13,176	156	296	4,806
Computer Equipment: Hardware	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	9,701,325	537	90,689	104,564	32,813	120,278	129,342	1,536	2,902	47,173
Transportation Equipment	484	1,239,187	69	11,584	13,356	4,191	15,364	16,521	196	371	6,026
Vehicle Conversion Kits	484.1	0	0	0	0	0	0	0	0	0	0
Heavy Work Equipment	485	678,212	40	10,135	20,621	6,826	11,148	0	0	0	0
Tools & Work Equipment	486	2,928,013	175	43,754	89,024	29,470	48,129	0	0	0	0
Rental Equipment: Conv. Bur.	487	0	0	0	0	0	0	0	0	0	0
Communication Equipment	488	43,106	2	403	465	146	534	575	7	13	210
Other General Equipment	489	0	0	0	0	0	0	0	0	0	0
Sub-total	480-490	25,965,213	1,453	262,904	350,638	111,920	336,486	298,098	3,539	6,688	108,721
Sub-total Plant-in-Service		634,052,162	35,834	8,410,494	16,322,883	5,758,100	9,762,564	298,098	3,539	6,688	108,721
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		**634,052,162**	**35,834**	**8,410,494**	**16,322,883**	**5,758,100**	**9,762,564**	**298,098**	**3,539**	**6,688**	**108,721**
II. ACCUMULATED DEPRECIATION											
Intangible Plant		-22,482	-1	-325	-593	-220	-350	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.
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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		-26,418,532		0	-26,418,532		-8,866,743	-1,446,259	-10,313,001	-7,181,558	-1,903,695
Distribution Plant		-185,658,131		0	-185,658,131		-120,863,470	-16,725,568	-137,589,038	-37,401,711	-6,071,604
General Plant		-17,708,350		0	-17,708,350		-11,926,696	-1,216,791	-13,143,486	-2,969,566	-588,989
Retirement Work in Progress		0		0	0		0	0	0	0	0
Sub-total		-229,807,496		0	-229,807,496		-141,670,310	-19,390,503	-161,060,813	-47,557,647	-8,565,182
Plant Held For Future Use		0		0	0		0	0	0	0	0
Total Accumulated Depreciation		**-229,807,496**		**0**	**-229,807,496**		**-141,670,310**	**-19,390,503**	**-161,060,813**	**-47,557,647**	**-8,565,182**
III. OTHER RATE BASE											
Contributions in Aid of Construction		-50,956,494		0	-50,956,494		-19,273,546	-3,099,097	-22,372,642	-14,068,091	-3,599,740
Cash Working Capital		20,209,219		0	20,209,219		6,621,239	774,721	7,395,960	1,928,583	353,323
Security Deposits		-500,000		0	-500,000		-401,313	-28,692	-430,005	-57,350	-7,913
Gas in Storage		75,807,923		0	75,807,923		31,275,820	4,758,916	36,034,735	25,897,672	6,808,266
Investment in DSM		37,058,080		0	37,058,080		22,234,848	6,299,874	28,534,721	7,782,197	370,581
Total Other Rate Base		**81,618,728**		**0**	**81,618,728**		**40,457,047**	**8,705,721**	**49,162,769**	**21,483,011**	**3,924,517**
TOTAL RATE BASE		**485,863,394**		**0**	**485,863,394**		**279,512,955**	**42,103,578**	**321,616,532**	**108,885,613**	**20,229,749**

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Allocation Results of Rate Base
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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		-26,418,532	-3,965	-1,341,204	-3,962,799	-974,810	-737,501	0	0	0	0
Distribution Plant		-185,658,131	-8,334	-1,274,219	-137,362	-784,441	-2,391,422	0	0	0	0
General Plant		-17,708,350	-936	-162,607	-247,028	-78,942	-239,726	-198,045	-2,351	-4,443	-72,230
Retirement Work in Progress		0	0	0	0	0	0	0	0	0	0
Sub-total		-229,807,496	-13,236	-2,778,355	-4,347,782	-1,838,413	-3,368,998	-198,045	-2,351	-4,443	-72,230
Plant Held For Future Use		0	0	0	0	0	0	0	0	0	0
Total Accumulated Depreciation		**-229,807,496**	**-13,236**	**-2,778,355**	**-4,347,782**	**-1,838,413**	**-3,368,998**	**-198,045**	**-2,351**	**-4,443**	**-72,230**
III. OTHER RATE BASE											
Contributions in Aid of Construction		-50,956,494	-6,447	-2,136,779	-5,911,318	-1,475,197	-1,386,279	0	0	0	0
Cash Working Capital		20,209,219	642	113,312	78,169	34,806	149,526	9,596,731	121,597	229,792	206,778
Security Deposits		-500,000	-82	-653	-82	-163	-3,753	0	0	0	0
Gas in Storage		75,807,923	14,207	1,707,774	0	0	5,345,268	0	0	0	0
Investment in DSM		37,058,080	0	370,581	0	0	0	0	0	0	0
Total Other Rate Base		**81,618,728**	**8,320**	**54,235**	**-5,833,230**	**-1,440,554**	**4,104,762**	**9,596,731**	**121,597**	**229,792**	**206,778**
TOTAL RATE BASE		**485,863,394**	**30,919**	**5,686,374**	**6,141,871**	**2,479,133**	**10,498,328**	**9,696,784**	**122,785**	**232,036**	**243,269**

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Allocation Results of Cost of Service Elements
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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											
TCPL FS Demand - Sask Zone		220,729		0	220,729		98,011	16,027	114,038	79,316	17,702
TCPL STS Demand		1,591,290		0	1,591,290		706,586	115,544	822,130	571,811	127,618
TCPL FS Demand - SSDA (Welwyn)		9,859,237		0	9,859,237		4,377,831	715,884	5,093,715	3,542,798	790,692
TCPL FS Demand - SSDA (Welwyn) to Man Zone		7,865,053		0	7,865,053		3,492,347	571,085	4,063,432	2,826,212	630,762
TCPL FS Demand - Man Zone		1,738,049		0	1,738,049		771,752	126,201	897,952	624,547	139,388
Storage Capacity Charge		6,065,784		0	6,065,784		2,693,411	440,439	3,133,850	2,179,666	486,464
Storage Deliverability Charge		4,805,100		0	4,805,100		2,133,625	348,901	2,482,526	1,726,655	385,360
ANR Oklahoma Demand		522,334		0	522,334		231,934	37,927	269,861	187,695	41,890
ANR Louisiana Demand		1,523,565		0	1,523,565		676,514	110,627	787,140	547,475	122,187
ANR Crystal Falls to Storage Demand		1,777,913		0	1,777,913		789,453	129,095	918,548	638,872	142,585
GLGT Emerson to Crystal Falls Demand		2,160,818		0	2,160,818		959,475	156,898	1,116,373	776,464	173,294
GLGT Backhaul Demand		1,054,553		0	1,054,553		468,257	76,572	544,828	378,941	84,573
Forecast Capacity Management Revenues		-6,800,000		0	-6,800,000		-3,019,428	-493,751	-3,513,179	-2,443,498	-545,347
Sub-total		32,384,424		0	32,384,424		14,379,768	2,351,448	16,731,215	11,636,953	2,597,170
B. VARIABLE TRANSPORTATION											
TCPL FS - Sask Zone		7,690		0	7,690		3,173	483	3,655	2,627	691
TCPL FS - Flowing directly to Man Zone		41,200		0	41,200		16,998	2,586	19,584	14,075	3,700
TCPL FS - SSDA (Welwyn)		566,137		0	566,137		233,569	35,540	269,109	193,405	50,844
TCPL FS - SSDA (Welwyn) to Man Zone		348,338		0	348,338		143,713	21,867	165,580	119,000	31,284
ANR Oklahoma to Crystall Falls		20,769		0	20,769		8,877	1,429	10,306	7,326	1,583
ANR Storage Transportation		80,548		0	80,548		34,429	5,541	39,970	28,413	6,140
Storage Withdrawl Chg.		125,410		0	125,410		53,605	8,627	62,232	44,238	9,560
Storage Gas - Transportation & Delivery Cost		4,265,858		0	4,265,858		1,823,382	293,444	2,116,826	1,504,778	325,179
Compressor Fuel: TCPL SSDA		16,130		0	16,130		0	0	0	0	0
Compressor Fuel: TCPL MDA		267,265		0	267,265		0	0	0	0	0
Compressor Fuel: TCPL to SSDA (Welwyn)		943,271		0	943,271		0	0	0	0	0
Compressor Fuel: TCPL SSDA (Welwyn) to MDA		444,216		0	444,216		0	0	0	0	0
Compressor Fuel: Oklahoma		149,278		0	149,278		63,807	10,269	74,075	52,658	11,379
Compressor Fuel: Storage		459,370		0	459,370		196,351	31,600	227,951	162,043	35,017
Sub-total		7,735,482		0	7,735,482		2,577,904	411,385	2,989,289	2,128,563	475,377
C. COMMODITY COST											
Primary Direct to System		265,213,668		0	265,213,668		1,440,162	219,134	1,659,296	1,188,298	380,255
Storage Gas: Primary to System		71,650,375		0	71,650,375		389,076	59,202	448,277	321,032	102,730
Oklahoma Supply		4,140,315		0	4,140,315		18,830	2,865	21,695	15,537	4,972
Storage Gas: Supplemental Supply		0		0	0		0	0	0	0	0
Seasonal Delivered Service		8,216,051		0	8,216,051		37,367	5,686	43,052	30,832	9,866
Delivered Service		13,052		0	13,052		59	9	68	49	16
Fixed Price Offering		5,934,032		0	5,934,032		32,223	4,903	37,126	26,588	8,508
Sub-total		355,167,494		0	355,167,494		1,917,717	291,799	2,209,516	1,582,335	506,347
D. OTHER GAS COSTS											
Minell Charges		198,444		0	198,444		66,603	10,864	77,467	53,945	14,300
Load Balancing Charges		228,000		0	228,000		101,240	16,555	117,795	81,929	18,285
Baseload Volume Price Increment Charges		154,307		0	154,307		68,518	11,204	79,722	55,449	12,375
Sub-total		580,751		0	580,751		236,360	38,623	274,983	191,322	44,960
Total Cost of Gas		**395,868,151**		**0**	**395,868,151**		**19,111,748**	**3,093,255**	**22,205,004**	**15,539,174**	**3,623,854**
II. OTHER REVENUE											
Rental Income		-39,786		0	-39,786		-37,131	-2,655	-39,786	0	0
Late Payment Charge		-1,849,388		0	-1,849,388		-1,725,988	-123,400	-1,849,388	0	0
Broker Revenue		-136,616		0	-136,616		-101,882	-11,905	-113,787	-19,169	-1,902
Other		0		0	0		0	0	0	0	0
Total Other Revenue		**-2,025,790**		**0**	**-2,025,790**		**-1,865,001**	**-137,959**	**-2,002,960**	**-19,169**	**-1,902**

Centra Gas Manitoba Inc.
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Allocation Results of Cost of Service Elements
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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		220,729	44	3,661	0	0	5,967	0	0	0	0
TCPL STS Demand		1,591,290	316	26,395	0	0	43,019	0	0	0	0
TCPL FS Demand - SSDA (Welwyn)		9,859,237	1,956	163,538	0	0	266,537	0	0	0	0
TCPL FS Demand - SSDA (Welwyn) to Man Zone		7,865,053	1,561	130,460	0	0	212,626	0	0	0	0
TCPL FS Demand - Man Zone		1,738,049	345	28,829	0	0	46,987	0	0	0	0
Storage Capacity Charge		6,065,784	1,204	100,615	0	0	163,984	0	0	0	0
Storage Deliverability Charge		4,805,100	954	79,703	0	0	129,902	0	0	0	0
ANR Oklahoma Demand		522,334	104	8,664	0	0	14,121	0	0	0	0
ANR Louisiana Demand		1,523,565	302	25,272	0	0	41,188	0	0	0	0
ANR Crystal Falls to Storage Demand		1,777,913	353	29,491	0	0	48,065	0	0	0	0
GLGT Emerson to Crystal Falls Demand		2,160,818	429	35,842	0	0	58,416	0	0	0	0
GLGT Backhaul Demand		1,054,553	209	17,492	0	0	28,509	0	0	0	0
Forecast Capacity Management Revenues		-6,800,000	-1,349	-112,793	0	0	-183,833	0	0	0	0
Sub-total		32,384,424	6,426	537,169	0	0	875,489	0	0	0	0
B. VARIABLE TRANSPORTATION											
TCPL FS - Sask Zone		7,690	1	173	0	0	542	0	0	0	0
TCPL FS - Flowing directly to Man Zone		41,200	8	928	0	0	2,905	0	0	0	0
TCPL FS - SSDA (Welwyn)		566,137	106	12,754	0	0	39,919	0	0	0	0
TCPL FS - SSDA (Welwyn) to Man Zone		348,338	65	7,847	0	0	24,562	0	0	0	0
ANR Oklahoma to Crystall Falls		20,769	2	321	0	0	1,230	0	0	0	0
ANR Storage Transportation		80,548	9	1,246	0	0	4,770	0	0	0	0
Storage Withdrawl Chg.		125,410	14	1,939	0	0	7,427	0	0	0	0
Storage Gas - Transportation & Delivery Cost		4,265,858	463	65,972	0	0	252,641	0	0	0	0
Compressor Fuel: TCPL SSDA		16,130	0	0	0	0	0	16,130	0	0	0
Compressor Fuel: TCPL MDA		267,265	0	0	0	0	0	267,265	0	0	0
Compressor Fuel: TCPL to SSDA (Welwyn)		943,271	0	0	0	0	0	943,271	0	0	0
Compressor Fuel: TCPL SSDA (Welwyn) to MDA		444,216	0	0	0	0	0	444,216	0	0	0
Compressor Fuel: Oklahoma		149,278	16	2,309	0	0	8,841	0	0	0	0
Compressor Fuel: Storage		459,370	50	7,104	0	0	27,206	0	0	0	0
Sub-total		7,735,482	734	100,593	0	0	370,043	1,670,883	0	0	0
C. COMMODITY COST											
Primary Direct to System		265,213,668	0	315,439	120,990	237,660	419,145	260,892,583	0	0	0
Storage Gas: Primary to System		71,650,375	0	85,219	32,687	64,206	113,237	70,482,987	0	0	0
Oklahoma Supply		4,140,315	0	4,124	1,582	3,107	5,480	0	1,410,374	2,673,443	0
Storage Gas: Supplemental Supply		0	0	0	0	0	0	0	0	0	0
Seasonal Delivered Service		8,216,051	0	8,184	3,139	6,166	10,875	0	2,798,749	5,305,187	0
Delivered Service		13,052	0	13	5	10	17	0	12,874	0	0
Fixed Price Offering		5,934,032	0	7,058	2,707	5,318	9,378	0	0	0	5,837,350
Sub-total		355,167,494	0	420,038	161,111	316,467	558,133	331,375,570	4,221,998	7,978,629	5,837,350
D. OTHER GAS COSTS											
Minell Charges		198,444	30	10,074	29,768	7,322	5,539	0	0	0	0
Load Balancing Charges		228,000	45	3,782	0	0	6,164	0	0	0	0
Baseload Volume Price Increment Charges		154,307	31	2,560	0	0	4,172	0	0	0	0
Sub-total		580,751	106	16,416	29,768	7,322	15,875	0	0	0	0
Total Cost of Gas		**395,868,151**	**7,266**	**1,074,216**	**190,878**	**323,789**	**1,819,540**	**333,046,453**	**4,221,998**	**7,978,629**	**5,837,350**
II. OTHER REVENUE											
Rental Income		-39,786	0	0	0	0	0	0	0	0	0
Late Payment Charge		-1,849,388	0	0	0	0	0	0	0	0	0
Broker Revenue		-136,616	-5	-331	-175	-407	-841	0	0	0	0
Other		0	0	0	0	0	0	0	0	0	0
Total Other Revenue		**-2,025,790**	**-5**	**-331**	**-175**	**-407**	**-841**	**0**	**0**	**0**	**0**

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Allocation Results of Cost of Service Elements
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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		234,000		0	234,000		163,457	15,468	178,925	35,755	7,053
Insurance		62,000		0	62,000		43,309	4,098	47,407	9,473	1,869
Public Affairs		801,000		0	801,000		559,525	52,947	612,473	122,391	24,143
Sub-total		1,097,000		0	1,097,000		766,291	72,514	838,804	167,619	33,065
B. FINANCE & ADMINISTRATION											
Customer Billing		3,560,000		6,000	3,554,000		3,217,570	230,041	3,447,611	104,492	1,287
Banner System		1,108,000		0	1,108,000		1,003,114	71,718	1,074,832	32,577	401
Gas IT		325,000		0	325,000		226,697	21,429	248,126	49,396	9,729
Gas Accounting		405,000		8,000	397,000		19,166	3,102	22,268	15,584	3,634
Gas Regulatory		2,761,000		33,000	2,728,000		1,902,857	179,873	2,082,730	414,621	81,661
Gas Supply		2,985,473		93,416	2,892,057		935,636	152,506	1,088,142	758,704	181,971
Treasury		336,000		0	336,000		234,369	22,154	256,524	51,068	10,058
Sub-total		11,480,473		140,416	11,340,057		7,539,410	680,822	8,220,232	1,426,440	288,741
C. TRANSMISSION & DISTRIBUTION											
Property Taxes		67,000		0	67,000		39,998	5,621	45,620	14,408	2,650
Research & Development		60,000		0	60,000		33,837	4,213	38,051	16,252	4,161
Station Maintenance		4,967,000		580,210	4,386,790		2,699,656	332,035	3,031,692	1,263,534	323,636
System Integrity		1,665,000		0	1,665,000		835,602	107,041	942,643	427,364	110,188
System Maintenance & Support		616,000		0	616,000		309,148	39,602	348,750	158,112	40,766
System Support & Communication Systems		258,000		0	258,000		43,894	7,169	51,063	35,537	102,012
Sub-total		7,633,000		580,210	7,052,790		3,962,136	495,682	4,457,818	1,915,207	583,413
D. POWER SUPPLY											
Health, Safety, Environment		232,000		0	232,000		116,432	14,915	131,347	59,549	15,353
Sub-total		232,000		0	232,000		116,432	14,915	131,347	59,549	15,353
E. CUSTOMER SERVICE & MARKETING											
Billing Inquiries & Collections		11,071,000		2,978,947	8,092,053		8,992,153	758,149	9,750,302	1,075,056	128,067
Customer Inspections		10,799,000		2,908,865	7,890,135		9,532,309	699,361	10,231,671	367,196	44,403
Customer Relations		6,420,000		165,000	6,255,000		3,426,958	352,534	3,779,492	1,490,398	527,176
Customer Safety		2,660,000		0	2,660,000		1,699,477	121,504	1,820,981	822,999	10,026
Work Coordination		2,914,000		0	2,914,000		2,416,873	210,864	2,627,737	277,301	5,208
Distribution Maintenance		8,744,000		0	8,744,000		5,265,737	764,951	6,030,688	1,834,852	348,015
Emergency		107,000		0	107,000		85,881	6,140	92,021	12,273	1,693
Load Forecast		225,000		13,000	212,000		115,220	8,238	123,458	4,289	53,068
Meter Reading		1,873,000		0	1,873,000		1,423,338	179,900	1,603,237	254,127	9,454
Metering		4,696,000		0	4,696,000		3,450,912	246,724	3,697,636	924,413	46,280
Sub-total		49,509,000		6,065,812	43,443,188		36,408,859	3,348,364	39,757,223	7,062,902	1,173,390
F. ADJUSTMENTS TO INCOME											
Corporate Alloc. & Adj.		-713,000		0	-713,000		-497,338	-47,012	-544,350	-108,367	-21,343
Depreciation, Interest, Taxes		-8,895,000		0	-8,895,000		-6,204,514	-586,498	-6,791,012	-1,351,925	-266,267
Sub-total		-9,608,000		0	-9,608,000		-6,701,851	-633,510	-7,335,361	-1,460,291	-287,611
Total Operating & Maintenance Expenses		**60,343,473**		**6,786,439**	**53,557,034**		**42,091,276**	**3,978,788**	**46,070,064**	**9,171,425**	**1,806,352**

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Allocation Results of Cost of Service Elements
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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											
Audit		234,000	11	1,663	2,522	791	2,915	3,120	37	70	1,138
Insurance		62,000	3	441	668	210	772	827	10	19	301
Public Affairs		801,000	39	5,694	8,633	2,709	9,977	10,679	127	240	3,895
Sub-total		1,097,000	53	7,798	11,824	3,710	13,664	14,626	174	328	5,334
B. FINANCE & ADMINISTRATION											
Customer Billing		3,560,000	0	0	0	0	610	0	0	0	6,000
Banner System		1,108,000	0	0	0	0	190	0	0	0	0
Gas IT		325,000	18	3,038	3,503	1,099	4,029	4,333	51	97	1,580
Gas Accounting		405,000	7	1,077	191	325	1,825	333,999	4,234	8,001	13,854
Gas Regulatory		2,761,000	151	25,502	29,403	9,227	33,822	36,371	432	816	46,265
Gas Supply		2,985,473	407	77,004	164,196	40,388	71,670	538,811	6,128	11,580	46,473
Treasury		336,000	19	3,141	3,622	1,136	4,166	4,480	53	101	1,634
Sub-total		11,480,473	601	109,762	200,915	52,175	116,313	917,993	10,898	20,596	115,806
C. TRANSMISSION & DISTRIBUTION											
Property Taxes		67,000	4	898	1,760	622	1,039	0	0	0	0
Research & Development		60,000	0	0	0	0	1,536	0	0	0	0
Station Maintenance		4,967,000	679	226,167	0	4	121,289	0	0	0	0
System Integrity		1,665,000	90	30,598	90,412	22,239	41,465	0	0	0	0
System Maintenance & Support		616,000	33	11,320	33,450	8,228	15,341	0	0	0	0
System Support & Communication Systems		258,000	20	14,215	4,825	2,862	47,466	0	0	0	0
Sub-total		7,633,000	826	283,198	130,447	33,955	228,135	0	0	0	0
D. POWER SUPPLY											
Health, Safety, Environment		232,000	13	4,264	12,598	3,099	5,778	0	0	0	0
Sub-total		232,000	13	4,264	12,598	3,099	5,778	0	0	0	0
E. CUSTOMER SERVICE & MARKETING											
Billing Inquiries & Collections		11,071,000	1,320	10,562	1,320	2,641	60,733	0	0	0	41,000
Customer Inspections		10,799,000	110	29,648	87,088	21,461	17,424	0	0	0	0
Customer Relations		6,420,000	0	80,485	76,541	59,962	240,944	0	0	0	165,000
Customer Safety		2,660,000	103	827	103	207	4,754	0	0	0	0
Work Coordination		2,914,000	0	61	0	0	3,692	0	0	0	0
Distribution Maintenance		8,744,000	350	117,996	231,961	57,057	123,081	0	0	0	0
Emergency		107,000	17	140	17	35	803	0	0	0	0
Load Forecast		225,000	0	4,377	547	1,094	25,166	0	0	0	13,000
Meter Reading		1,873,000	0	982	123	245	4,832	0	0	0	0
Metering		4,696,000	477	3,817	477	954	21,947	0	0	0	0
Sub-total		49,509,000	2,378	248,894	398,179	143,656	503,377	0	0	0	219,000
F. ADJUSTMENTS TO INCOME											
Corporate Alloc. & Adj.		-713,000	-39	-6,665	-7,685	-2,412	-8,840	-9,506	-113	-213	-3,467
Depreciation, Interest, Taxes		-8,895,000	-492	-83,152	-95,874	-30,085	-110,281	-118,591	-1,408	-2,661	-43,252
Sub-total		-9,608,000	-532	-89,817	-103,559	-32,497	-119,121	-128,097	-1,521	-2,874	-46,719
Total Operating & Maintenance Expenses		**60,343,473**	**3,340**	**564,099**	**650,404**	**204,099**	**748,146**	**804,522**	**9,551**	**18,050**	**293,421**

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Allocation Results of Cost of Service Elements
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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
IV. DEPRECIATION & AMORTIZATION											
Depreciation Expense		18,144,318		0	18,144,318		11,369,829	1,571,142	12,940,971	3,647,998	603,193
Amortization of Cust. Contributions		-996,299		0	-996,299		-58,690	64,220	5,530	-229,517	-120,456
Depreciation: Common Assets		4,251,000		0	4,251,000		2,965,193	280,293	3,245,485	646,097	127,252
Amortization Expense (Deferreds)		1,050,416		108,000	942,416		562,615	79,068	641,683	202,668	37,272
Demand Side Management Amortization Expense (Deferred)		4,918,053		0	4,918,053		2,950,832	836,069	3,786,901	1,032,791	49,181
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		**31,167,487**		**108,000**	**31,059,487**		**21,589,778**	**2,830,792**	**24,420,570**	**5,300,038**	**696,440**
V. CAPITAL & OTHER TAXES											
Municipal Taxes		15,664,700		0	15,664,700		9,351,702	1,314,261	10,665,962	3,368,717	619,522
Payroll Tax		780,780		0	780,780		544,616	51,481	596,097	118,668	23,372
Taxes on Common Assets		218,000		0	218,000		124,679	18,901	143,580	49,359	9,221
Corporate Capital Tax		2,768,746		0	2,768,746		1,583,510	240,058	1,823,568	626,889	117,111
Business Taxes		0		0	0		0	0	0	0	0
Other		0		0	0		0	0	0	0	0
Income Taxes		4,507,827		0	4,507,827		2,578,131	390,841	2,968,972	1,020,645	190,670
Total Taxes		**23,940,053**		**0**	**23,940,053**		**14,182,639**	**2,015,542**	**16,198,180**	**5,184,278**	**959,896**
VI. FINANCE EXPENSE		**19,105,000**		**0**	**19,105,000**		**10,990,939**	**1,655,586**	**12,646,526**	**4,281,573**	**795,469**
VII. CORPORATE ALLOCATION		**12,000,000**		**0**	**12,000,000**		**6,903,495**	**1,039,887**	**7,943,382**	**2,689,290**	**499,640**
VIII. NET INCOME (LOSS)		**2,353,000**		**0**	**2,353,000**		**1,353,660**	**203,904**	**1,557,565**	**527,325**	**97,971**
COST OF SERVICE SUMMARY											
COST OF GAS		395,868,151		0	395,868,151		19,111,748	3,093,255	22,205,004	15,539,174	3,623,854
OTHER REVENUE		-2,025,790		0	-2,025,790		-1,865,001	-137,959	-2,002,960	-19,169	-1,902
OPERATING EXPENSES											
President & CEO		1,097,000		0	1,097,000		766,291	72,514	838,804	167,619	33,065
Finance & Administration		11,480,473		140,416	11,340,057		7,539,410	680,822	8,220,232	1,426,440	288,741
Transmission & Distribution		7,633,000		580,210	7,052,790		3,962,136	495,682	4,457,818	1,915,207	583,413
Power Supply		232,000		0	232,000		116,432	14,915	131,347	59,549	15,353
Customer Service & Marketing		49,509,000		6,065,812	43,443,188		36,408,859	3,348,364	39,757,223	7,062,902	1,173,390
Adjustments to Income		-9,608,000		0	-9,608,000		-6,701,851	-633,510	-7,335,361	-1,460,291	-287,611
Sub-total		60,343,473		6,786,439	53,557,034		42,091,276	3,978,788	46,070,064	9,171,425	1,806,352
DEPRECIATION & AMORTIZATION		31,167,487		108,000	31,059,487		21,589,778	2,830,792	24,420,570	5,300,038	696,440
CAPITAL & OTHER TAXES		23,940,053		0	23,940,053		14,182,639	2,015,542	16,198,180	5,184,278	959,896
FINANCE EXPENSE		19,105,000		0	19,105,000		10,990,939	1,655,586	12,646,526	4,281,573	795,469
CORPORATE ALLOCATION		12,000,000		0	12,000,000		6,903,495	1,039,887	7,943,382	2,689,290	499,640
NET INCOME		2,353,000		0	2,353,000		1,353,660	203,904	1,557,565	527,325	97,971
COST OF SERVICE		542,751,374		6,894,439	535,856,935		114,358,534	14,679,795	129,038,329	42,673,933	8,477,721

Centra Gas Manitoba Inc.
2009/10 and 2010/11 General Rate Application
Allocation Results of Cost of Service Elements
Non-Gas Cost Allocation Reflecting Orders 128/09 and 41/10

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		18,144,318	1,130	220,449	310,796	149,017	241,108	21,198	252	476	7,731
Amortization of Cust. Contributions		-996,299	-267	-77,637	-374,334	-151,141	-48,478	0	0	0	0
Depreciation: Common Assets		4,251,000	235	39,739	45,819	14,378	52,704	56,676	673	1,272	20,671
Amortization Expense (Deferreds)		1,050,416	53	12,627	24,754	8,750	14,609	0	0	0	108,000
Demand Side Management Amortization Expense (Deferred)		4,918,053	0	49,181	0	0	0	0	0	0	0
Furnace Replacement Program		3,800,000	0	0	0	0	0	0	0	0	0
Ex-Franchise Depreciation & Amortization		0	0	0	0	0	0	0	0	0	0
Total Depreciation & Amortization Expenses		**31,167,487**	**1,152**	**244,359**	**7,035**	**21,004**	**259,943**	**77,874**	**925**	**1,747**	**136,402**
V. CAPITAL & OTHER TAXES											
Municipal Taxes		15,664,700	886	209,887	411,455	145,449	242,822	0	0	0	0
Payroll Tax		780,780	43	7,299	8,416	2,641	9,680	10,410	124	234	3,797
Taxes on Common Assets		218,000	14	2,575	2,756	1,112	4,764	4,351	55	104	109
Corporate Capital Tax		2,768,746	177	32,704	35,000	14,128	60,503	55,258	700	1,322	1,386
Business Taxes		0	0	0	0	0	0	0	0	0	0
Other		0	0	0	0	0	0	0	0	0	0
Income Taxes		4,507,827	288	53,246	56,984	23,001	98,505	89,966	1,139	2,153	2,257
Total Taxes		**23,940,053**	**1,408**	**305,711**	**514,611**	**186,331**	**416,273**	**159,985**	**2,018**	**3,813**	**7,549**
VI. FINANCE EXPENSE		**19,105,000**	**1,216**	**223598**	**241,509**	**97,484**	**412,813**	**381,294**	**4,828**	**9,124**	**9,566**
VII. CORPORATE ALLOCATION		**12,000,000**	**764**	**140,444**	**151,694**	**61,230**	**259,291**	**239,494**	**3,033**	**5,731**	**6,008**
VIII. NET INCOME (LOSS)		**2,353,000**	**150**	**27,539**	**29,745**	**12,006**	**50,843**	**46,961**	**595**	**1,124**	**1,178**
COST OF SERVICE SUMMARY											
COST OF GAS		395,868,151	7,266	1,074,216	190,878	323,789	1,819,540	333,046,453	4,221,998	7,978,629	5,837,350
OTHER REVENUE		-2,025,790	-5	-331	-175	-407	-841	0	0	0	0
OPERATING EXPENSES											
President & CEO		1,097,000	53	7,798	11,824	3,710	13,664	14,626	174	328	5,334
Finance & Administration		11,480,473	601	109,762	200,915	52,175	116,313	917,993	10,898	20,596	115,806
Transmission & Distribution		7,633,000	826	283,198	130,447	33,955	228,135	0	0	0	0
Power Supply		232,000	13	4,264	12,598	3,099	5,778	0	0	0	0
Customer Service & Marketing		49,509,000	2,378	248,894	398,179	143,656	503,377	0	0	0	219,000
Adjustments to Income		-9,608,000	-532	-89,817	-103,559	-32,497	-119,121	-128,097	-1,521	-2,874	-46,719
Sub-total		60,343,473	3,340	564,099	650,404	204,099	748,146	804,522	9,551	18,050	293,421
DEPRECIATION & AMORTIZATION		31,167,487	1,152	244,359	7,035	21,004	259,943	77,874	925	1,747	136,402
CAPITAL & OTHER TAXES		23,940,053	1,408	305,711	514,611	186,331	416,273	159,985	2,018	3,813	7,549
FINANCE EXPENSE		19,105,000	1,216	223598	241,509	97,484	412,813	381,294	4,828	9,124	9,566
CORPORATE ALLOCATION		12,000,000	764	140,444	151,694	61,230	259,291	239,494	3,033	5,731	6,008
NET INCOME		2,353,000	150	27,539	29,745	12,006	50,843	46,961	595	1,124	1,178
COST OF SERVICE		542,751,374	15,290	2,579,634	1,785,700	905,537	3,966,007	334,756,583	4,242,946	8,018,218	6,291,474

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Combined Annual Bill Impacts

February 1, 2010 Billed Rates vs. May 1, 2010 Billed Rates

			FEBRUARY 1, 2010 BILLED RATES				**MAY 1, 2010 BILLED RATES**				**BILL IMPACTS**	
	Load Factor	Annual Use m³	Basic Chg	Demand	Commodity	Annual	Basic Chg	Demand	Commodity	Annual	$	%
Small General Service		1,000	$156	$0	$345	$501	$168	$0	$314	$482	($19)	-3.7%
		1,980	$156	$0	$682	$838	$168	$0	$622	$790	($49)	-5.8%
(Typical Residential Customer)		2,533	$156	$0	$873	$1,029	$168	$0	$795	$963	($66)	-6.4%
		2,800	$156	$0	$965	$1,121	$168	$0	$879	$1,047	($74)	-6.6%
		3,200	$156	$0	$1,103	$1,259	$168	$0	$1,005	$1,173	($86)	-6.8%
		3,680	$156	$0	$1,268	$1,424	$168	$0	$1,155	$1,323	($101)	-7.1%
		11,330	$156	$0	$3,904	$4,060	$168	$0	$3,557	$3,725	($335)	-8.2%
Large General Service		11,331	$840	$0	$3,302	$4,142	$924	$0	$2,971	$3,895	($247)	-6.0%
		59,488	$840	$0	$17,333	$18,173	$924	$0	$15,597	$16,521	($1,652)	-9.1%
		679,868	$840	$0	$198,092	$198,932	$924	$0	$178,256	$179,180	($19,751)	-9.9%
High Volume Firm	25%	850,000	$12,486	$48,574	$199,188	$260,249	$13,420	$47,797	$180,030	$241,247	($19,002)	-7.3%
	40%	850,000	$12,486	$30,359	$199,188	$242,033	$13,420	$29,873	$180,030	$223,323	($18,710)	-7.7%
	40%	1,416,392	$12,486	$50,588	$331,916	$394,991	$13,420	$49,779	$299,992	$363,191	($31,800)	-8.1%
	40%	2,832,784	$12,486	$101,177	$663,831	$777,495	$13,420	$99,559	$599,984	$712,962	($64,533)	-8.3%
	40%	6,200,000	$12,486	$221,442	$1,452,901	$1,686,829	$13,420	$217,900	$1,313,160	$1,544,480	($142,349)	-8.4%
	40%	12,600,000	$12,486	$450,027	$2,952,669	$3,415,183	$13,420	$442,830	$2,668,680	$3,124,929	($290,254)	-8.5%
	75%	849,835	$12,486	$16,188	$199,149	$227,824	$13,420	$15,929	$179,995	$209,344	($18,480)	-8.1%
	75%	1,416,392	$12,486	$26,981	$331,916	$371,383	$13,420	$26,549	$299,992	$339,961	($31,422)	-8.5%
	75%	2,832,784	$12,486	$53,961	$663,831	$730,279	$13,420	$53,098	$599,984	$666,501	($63,777)	-8.7%
	75%	6,200,000	$12,486	$118,102	$1,452,901	$1,583,490	$13,420	$116,213	$1,313,160	$1,442,793	($140,696)	-8.9%
	75%	12,600,000	$12,486	$240,015	$2,952,669	$3,205,170	$13,420	$236,176	$2,668,680	$2,918,276	($286,895)	-9.0%
Co-op	35%	250,000	$3,603	$9,360	$55,198	$68,161	$3,289	$10,845	$47,675	$61,808	($6,353)	-9.3%
	35%	350,000	$3,603	$13,105	$77,277	$93,985	$3,289	$15,182	$66,745	$85,216	($8,768)	-9.3%
	35%	500,000	$3,603	$18,721	$110,396	$132,720	$3,289	$21,689	$95,350	$120,328	($12,392)	-9.3%
Mainline Firm	40%	2,832,784	$17,943	$129,054	$640,522	$787,518	$28,240	$122,749	$574,772	$725,761	($61,758)	-7.8%
	40%	14,163,920	$17,943	$645,270	$3,202,609	$3,865,822	$28,240	$613,744	$2,873,859	$3,515,843	($349,979)	-9.1%
	40%	28,327,840	$17,943	$1,290,540	$6,405,219	$7,713,702	$28,240	$1,227,488	$5,747,719	$7,003,447	($710,255)	-9.2%
	75%	2,832,784	$17,943	$68,829	$640,522	$727,293	$28,240	$65,466	$574,772	$668,478	($58,815)	-8.1%
	75%	14,163,920	$17,943	$344,144	$3,202,609	$3,564,696	$28,240	$327,330	$2,873,859	$3,229,429	($335,267)	-9.4%
	75%	28,327,840	$17,943	$688,288	$6,405,219	$7,111,449	$28,240	$654,660	$5,747,719	$6,430,619	($680,831)	-9.6%
	75%	41,000,000	$17,943	$996,187	$9,270,526	$10,284,655	$28,240	$947,516	$8,318,900	$9,294,656	($989,999)	-9.6%
Special Contract	94%	451,570,000	$1,550,079	$0	$161,762	$1,711,841	$1,624,034	$0	$90,314	$1,610,622	($101,219)	-5.9%
Power Stations	5%	12,117,000	$304,393	$122,973	$272,633	$699,999	$277,574	$237,371	-$126,350	$388,595	($311,404)	-44.5%
Interruptible Sales	25%	849,835	$12,346	$27,185	$214,648	$254,179	$12,513	$22,888	$173,961	$209,362	($44,817)	-17.6%
	40%	2,832,784	$12,346	$56,635	$715,494	$784,475	$12,513	$47,684	$579,871	$640,067	($144,408)	-18.4%
	40%	14,163,920	$12,346	$283,177	$3,577,469	$3,872,992	$12,513	$238,420	$2,899,354	$3,150,287	($722,705)	-18.7%
	75%	849,835	$12,346	$9,062	$214,648	$236,056	$12,513	$7,629	$173,961	$194,103	($41,953)	-17.8%
	75%	2,832,784	$12,346	$30,206	$715,494	$758,045	$12,513	$25,431	$579,871	$617,815	($140,231)	-18.5%
	75%	14,163,920	$12,346	$151,028	$3,577,469	$3,740,843	$12,513	$127,157	$2,899,354	$3,039,024	($701,819)	-18.8%

Firm Billing percentages: 95% Primary Gas, 5% Supplemental Gas
Interruptible Billing percentages: 67% Primary Gas, 33% Supplemental Gas

Centra Gas Manitoba Inc.
2010/11 Cost of Gas Application Reflecting B/O 41/10
Combined Annual Bill Impacts

February 1, 2010 Base Rates vs. May 1, 2010 Base Rates

			FEBRUARY 1, 2010 BASE RATES				**MAY 1, 2010 BASE RATES**				**BASE IMPACTS**	
	Load Factor	Annual Use m³	Basic Chg	Demand	Commodity	Annual	Basic Chg	Demand	Commodity	Annual	$	%
Small General Service		1,000	$156	$0	$334	$490	$168	$0	$315	$483	($7)	-1.3%
		1,980	$156	$0	$660	$816	$168	$0	$624	$792	($25)	-3.0%
(Typical Residential Customer)		2,533	$156	$0	$845	$1,001	$168	$0	$798	$966	($35)	-3.5%
		2,800	$156	$0	$934	$1,090	$168	$0	$882	$1,050	($40)	-3.7%
		3,200	$156	$0	$1,067	$1,223	$168	$0	$1,008	$1,176	($47)	-3.9%
		3,680	$156	$0	$1,227	$1,383	$168	$0	$1,159	$1,327	($56)	-4.1%
		11,330	$156	$0	$3,779	$3,935	$168	$0	$3,569	$3,737	($198)	-5.0%
Large General Service		11,331	$840	$0	$3,194	$4,034	$924	$0	$2,981	$3,905	($129)	-3.2%
		59,488	$840	$0	$16,769	$17,609	$924	$0	$15,651	$16,575	($1,034)	-5.9%
		679,868	$840	$0	$191,650	$192,490	$924	$0	$178,868	$179,792	($12,698)	-6.6%
High Volume Firm	25%	850,000	$12,486	$36,285	$200,014	$248,786	$13,420	$41,963	$180,200	$235,582	($13,204)	-5.3%
	40%	850,000	$12,486	$22,678	$200,014	$235,179	$13,420	$26,227	$180,200	$219,846	($15,333)	-6.5%
	40%	1,416,392	$12,486	$37,790	$333,292	$383,569	$13,420	$43,702	$300,275	$357,397	($26,172)	-6.8%
	40%	2,832,784	$12,486	$75,580	$666,585	$754,651	$13,420	$87,405	$600,550	$701,375	($53,276)	-7.1%
	40%	6,200,000	$12,486	$165,419	$1,458,928	$1,636,833	$13,420	$191,300	$1,314,400	$1,519,119	($117,713)	-7.2%
	40%	12,600,000	$12,486	$336,174	$2,964,917	$3,313,578	$13,420	$388,770	$2,671,200	$3,073,390	($240,188)	-7.2%
	75%	849,835	$12,486	$12,093	$199,975	$224,555	$13,420	$13,985	$180,165	$207,570	($16,985)	-7.6%
	75%	1,416,392	$12,486	$20,155	$333,292	$365,934	$13,420	$23,308	$300,275	$337,003	($28,931)	-7.9%
	75%	2,832,784	$12,486	$40,309	$666,585	$719,381	$13,420	$46,616	$600,550	$660,586	($58,795)	-8.2%
	75%	6,200,000	$12,486	$88,223	$1,458,928	$1,559,637	$13,420	$102,027	$1,314,400	$1,429,846	($129,791)	-8.3%
	75%	12,600,000	$12,486	$179,293	$2,964,917	$3,156,697	$13,420	$207,344	$2,671,200	$2,891,964	($264,733)	-8.4%
Co-op	35%	250,000	$3,603	$9,360	$54,423	$67,386	$3,289	$10,845	$48,275	$62,408	($4,978)	-7.4%
	35%	350,000	$3,603	$13,105	$76,192	$92,900	$3,289	$15,182	$67,585	$86,056	($6,843)	-7.4%
	35%	500,000	$3,603	$18,721	$108,846	$131,170	$3,289	$21,689	$96,550	$121,528	($9,642)	-7.4%
Mainline Firm	40%	2,832,784	$17,943	$112,471	$626,266	$756,679	$28,240	$131,294	$553,809	$713,343	($43,336)	-5.7%
	40%	14,163,920	$17,943	$562,353	$3,131,329	$3,711,625	$28,240	$656,469	$2,769,046	$3,453,755	($257,870)	-6.9%
	40%	28,327,840	$17,943	$1,124,707	$6,262,658	$7,405,307	$28,240	$1,312,937	$5,538,093	$6,879,270	($526,037)	-7.1%
	75%	2,832,784	$17,943	$59,984	$626,266	$704,193	$28,240	$70,023	$553,809	$652,073	($52,120)	-7.4%
	75%	14,163,920	$17,943	$299,922	$3,131,329	$3,449,193	$28,240	$350,117	$2,769,046	$3,147,403	($301,790)	-8.7%
	75%	28,327,840	$17,943	$599,844	$6,262,658	$6,880,444	$28,240	$700,233	$5,538,093	$6,266,566	($613,878)	-8.9%
	75%	41,000,000	$17,943	$868,177	$9,064,191	$9,950,311	$28,240	$1,013,475	$8,015,500	$9,057,215	($893,096)	-9.0%
Special Contract	94%	451,570,000	$1,550,079	$0	$161,762	$1,711,841	$1,624,034	$0	$90,314	$1,714,348	$2,506	0.1%
Power Stations	5%	12,117,000	$304,393	$127,604	$318,896	$750,894	$277,574	$234,881	$197,507	$709,962	($40,931)	-5.5%
Interruptible Sales	25%	849,835	$12,346	$18,607	$212,789	$243,742	$12,513	$20,161	$173,111	$205,785	($37,957)	-15.6%
	40%	2,832,784	$12,346	$38,765	$709,296	$760,407	$12,513	$42,003	$577,038	$631,554	($128,854)	-16.9%
	40%	14,163,920	$12,346	$193,824	$3,546,482	$3,752,652	$12,513	$210,014	$2,885,191	$3,107,717	($644,935)	-17.2%
	75%	849,835	$12,346	$6,202	$212,789	$231,337	$12,513	$6,720	$173,111	$192,345	($38,993)	-16.9%
	75%	2,832,784	$12,346	$20,675	$709,296	$742,317	$12,513	$22,402	$577,038	$611,952	($130,365)	-17.6%
	75%	14,163,920	$12,346	$103,373	$3,546,482	$3,662,201	$12,513	$112,008	$2,885,191	$3,009,711	($652,490)	-17.8%

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability:

SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m³
HVF:	For gas delivered through one meter at annual volumes greater than 680,000 m³
CO-OP:	For gas delivered to natural gas distribution cooperatives
MLC:	For gas delivered through one meter to customers served from the Transmission system
Special Contract:	For gas delivered under the terms of a Special Contract with the Company
Power Station:	For gas delivered under the terms of a Special Contract with the Company

Rates:

		Distribution to Customers			
	Transportation to Centra	Sales Service	T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm (HVF)	N/A	$1,118.31	$1,118.31	N/A	N/A
Cooperative (CO-OP)	N/A	$274.06	$274.06	N/A	N/A
Main Line Class (MLC)	N/A	$2,353.33	$2,353.33	N/A	N/A
Special Contract	N/A	N/A	$135,336.14	N/A	N/A
Power Station	N/A	N/A	$11,565.60	N/A	N/A
Monthly Demand Charge ($/m ^{3} /month)					
High Volume Firm Class (HVF)	$0.2250	$0.1504	$0.1504	N/A	N/A
Cooperative (CO-OP)	$0.3320	$0.1298	$0.1298	N/A	N/A
Main Line Class (MLC)	$0.4060	$0.1579	$0.1579	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0283	N/A	N/A
Commodity Volumetric Charge: ($/m ^{3})					
Small General Class (SGC)	$0.0409	$0.0874	N/A	$0.1869	$0.1827
Large General Class (LGC)	$0.0397	$0.0367	$0.0367	$0.1869	$0.1827
High Volume Firm (HVF)	$0.0167	$0.0086	$0.0086	$0.1869	$0.1827
Cooperative (CO-OP)	$0.0063	$0.0001	$0.0001	$0.1869	$0.1827
Main Line Class (MLC)	$0.0067	$0.0021	$0.0021	$0.1869	$0.1827
Special Contract	N/A	N/A	$0.0002	N/A	N/A
Power Station	N/A	N/A	$0.0163	N/A	N/A

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after May 1, 2010.

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES ONLY - NO RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability: For any consumer at one location whose annual natural gas requirements equal or exceed 680,000 m^3 and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:

		Distribution to Customers			
	Transportation to Centra	**Sales Service**	**T-Service**	**Primary Gas Supply**	**Supplemental Gas Supply[1]**
Basic Monthly Charge: ($/month)					
Interruptible Service	N/A	$1,042.72	$1,042.72	N/A	N/A
Mainline Interruptible (with firm delivery)	N/A	$2,353.33	$2,353.33	N/A	N/A
Monthly Demand Charge ($/m ^{3} /month)					
Interruptible Service	$0.1032	$0.0772	$0.0772	N/A	N/A
Mainline Interruptible (with firm delivery)	$0.1588	$0.1579	$0.1579	N/A	N/A
Commodity Volumetric Charge: ($/m ^{3})					
Interruptible Service	$0.0109	$0.0059	$0.0059	$0.1869	$0.1870
Mainline Interruptible (with firm delivery)	$0.0070	$0.0021	$0.0021	$0.1869	$0.1870
Alternate Supply Service:			Negotiated		
Gas Supply (Interruptible Sales and Mainline Interruptible)			Cost of Gas		
Delivery - Interruptible Class			$0.0084		
Delivery - Mainline Interruptible Class			$0.0073		

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to Basic Monthly Charge as described above, plus Demand charges as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after May 1, 2010.

CENTRA GAS MANITOBA INC.
FIRM SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES PLUS RIDERS)

Territory:	Entire natural gas service area of Company, including all zones
Availability:	
SGC:	For gas supplied through one domestic-sized meter.
LGC:	For gas delivered through one meter at annual volumes less than 680,000 m³
HVF:	For gas delivered to natural gas distribution cooperatives
CO-OP:	For gas delivered through one meter at annual volumes greater than 680,000 m³
MLC:	For gas delivered through one meter to customers served from the Transmission system
Special Contract:	For gas delivered under the terms of a Special Contract with the Company
Power Station:	For gas delivered under the terms of a Special Contract with the Company

Rates:

	Transportation to Centra	Distribution to Customers: Sales Service	Distribution to Customers: T-Service	Primary Gas Supply	Supplemental Gas Supply[1]
Basic Monthly Charge: ($/month)					
Small General Class (SGC)	N/A	$14.00	N/A	N/A	N/A
Large General Class (LGC)	N/A	$77.00	$77.00	N/A	N/A
High Volume Firm (HVF)	N/A	$1,118.31	$1,118.31	N/A	N/A
Cooperative (CO-OP)	N/A	$274.06	$274.06	N/A	N/A
Main Line Class (MLC)	N/A	$2,353.33	$2,353.33	N/A	N/A
Special Contract	N/A	N/A	$135,336.14	N/A	N/A
Power Station	N/A	N/A	$11,565.60	N/A	N/A
Monthly Demand Charge ($/m ^{3} /month)					
High Volume Firm Class (HVF)	$0.2763	$0.1513	$0.1513	N/A	N/A
Cooperative (CO-OP)	$0.3320	$0.1298	$0.1298	N/A	N/A
Main Line Class (MLC)	$0.3681	$0.1591	$0.1591	N/A	N/A
Special Contract	N/A	N/A	N/A	N/A	N/A
Power Station	N/A	N/A	$0.0286	N/A	N/A
Commodity Volumetric Charge: ($/m ^{3})					
Small General Class (SGC)	$0.0397	$0.0899	N/A	$0.1844	$0.1827
Large General Class (LGC)	$0.0388	$0.0391	$0.0374	$0.1844	$0.1827
High Volume Firm (HVF)	$0.0159	$0.0116	$0.0099	$0.1844	$0.1827
Cooperative (CO-OP)	$0.0063	$0.0001	$0.0001	$0.1844	$0.1827
Main Line Class (MLC)	$0.0138	$0.0048	$0.0031	$0.1844	$0.1827
Special Contract	N/A	N/A	$0.0002	N/A	N/A
Power Station	N/A	N/A	$0.0163	N/A	N/A
Power Station refund			-$0.0267		

¹ Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill:	Equal to the Basic Monthly Charge as described above, plus Demand Charge as appropriate.
Effective:	Rates to be charged for all billings based on gas consumed on and after May 1, 2010.

CENTRA GAS MANITOBA INC.
INTERRUPTIBLE SALES AND DELIVERY SERVICES
RATES SCHEDULES (BASE RATES PLUS RIDERS)

Territory: Entire natural gas service area of Company, including all zones

Availability: For any consumer at one location whose annual natural gas requirements equal or exceed 680,000 m^3 and who contracts for such service for a minimum of one year, or who received Interruptible Service continuously since December 31, 1996. Service under this rate shall be limited to the extent that the Company considers it has available natural gas supplies and/or capacity to provide delivery service.

Rates:

		Distribution to Customers			
	Transportation to Centra	**Sales Service**	**T-Service**	**Primary Gas Supply**	**Supplemental Gas Supply[1]**
Basic Monthly Charge: ($/month)					
Interruptible Service	N/A	$1,042.72	$1,042.72	N/A	N/A
Mainline Interruptible (with firm delivery)	N/A	$2,353.33	$2,353.33	N/A	N/A
Monthly Demand Charge ($/$m^3$/month)					
Interruptible Service	$0.1271	$0.0777	$0.0777	N/A	N/A
Mainline Interruptible (with firm delivery)	$0.1827	$0.1591	$0.1591	N/A	N/A
Commodity Volumetric Charge: ($/$m^3$)					
Interruptible Service	$0.0139	$0.0056	$0.0078	$0.1844	$0.1870
Mainline Interruptible (with firm delivery)	$0.0100	$0.0048	$0.0031	$0.1844	$0.1870
Alternate Supply Service:			Negotiated		
Gas Supply (Interruptible Sales and Mainline Interruptible)			Cost of Gas		
Delivery - Interruptible Class			$0.0104		
Delivery - Mainline Interruptible Class			$0.0083		

[1] Supplemental Gas is mandatory for all Sales and Western T-Service Customers.

Minimum Monthly Bill: Equal to Basic Monthly Charge as described above, plus Demand charges as appropriate.

Effective: Rates to be charged for all billings based on gas consumed on and after May 1, 2010.

PUB/CENTRA II-144

Reference: PUB/Centra I-11

b) Please re-tabulate the 2011/12 forecasted and actual cost of service using the CGM11-1 forecast instead of the CGM11-2 forecast, and note any material variances between the forecasted and actual results.

ANSWER:

The following table provides the requested information.

Comparison of Forecast with Actual Results **($000's)**

	2011/12 Forecast CGM 11-1	2011/12 Actual	Variance	Explanation
	[1]	[2]	[3] = [2] - [1]	[4]
Cost of Gas	244 918	197 099	(47 819)	Primarily due to warmer than normal weather and lower gas costs than forecasted partially offset by an increased number of customers and by higher usage.
Other Income	(1 347)	(991)	356	
Operating & Administrative	64 000	62 117	(1 883)	Primarily due to unallocated general contingency and lower than expected customer billing inquiries
Depreciation & Amortization	25 412	25 501	89	
Capital & Other Taxes	19 626	19 274	(352)	
Finance Expense	18 678	18 464	(214)	
Corporate Allocation	12 000	12 000	-	
Net Income (Loss)	(211)	(5 751)	(5 540)	Reduced net income primarily due to warmer weather partially offset by lower operating costs.
Total Cost of Service	383 076	327 713	(55 363)	

PUB/CENTRA II-145

Reference: PUB/Centra I-12

Please re-file the schedule in PUB/Centra I-12 reflecting the Furnace Replacement Program as a revenue requirement line item rather than a reduction to revenue.

ANSWER:

The schedule included below reflects the Furnace Replacement Program as a revenue requirement line item.

($000's)

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Test
Cost of Gas	430,759	315,840	260,835	197,099	175,576	168,279
Furnace Replacement Program	3,855	3,800	3,762	3,838	3,800	3,800
Other Income	(1,901)	(1,924)	(1,394)	(991)	(1,705)	(1,866)
Operating & Administrative	59,803	60,951	60,644	62,117	67,300	68,800
Depreciation & Amortization	24,901	23,697	25,591	25,501	27,620	30,091
Capital & Other Taxes	23,412	23,351	20,490	19,274	18,334	18,750
Finance Expense	20,158	18,921	17,888	18,464	17,901	17,296
Corporate Allocation	12,000	12,000	12,000	12,000	12,000	12,000
Net Income (Loss)	8,596	(950)	6,609	(5,751)	1,562	4,821
Total Cost of Service	581,583	455,685	406,425	331,551	322,388	321,971
Less: Cost of Gas	430,759	315,840	260,835	197,099	175,576	168,279
Less: Furnace Replacement Prograr	3,855	3,800	3,762	3,838	3,800	3,800
Non-Gas Cost of Service	146,969	136,045	141,828	130,615	143,012	149,892

PUB/CENTRA II-146

Reference: PUB/Centra I-16(a)

a) Other than escalation, please identify the cost pressures that are being exerted on Operations and Maintenance costs for maintaining the gas infrastructure.

ANSWER:

Cost pressures, other than escalation, that are being exerted on Operations and Maintenance costs for maintaining the gas infrastructure include:

- Negotiated general wage increases of 2.5% for 2010 through 2011, additional shift premiums and enhanced employee benefits;
- Changes to Measurement Canada standards with respect to compliance sampling specifications have resulted in significant increases in the number of annual gas meter exchanges.
- Legislative and policy changes to address workplace safety and health have increased the time and materials required to complete work procedures, with respect to:
    - Excavation Soft Dig – safe excavation practices have been modified from traditional backhoe methods to soft dig excavation to avoid damages affecting public safety and commerce;
    - Excavation Shoring – excavation in depths greater than 1.5m now have more stringent shoring requirements;
    - Entering Potential Flammable Atmospheres – operating procedures were changed to limit entrance into flammable atmospheres;

  - Traffic Control – traffic control in large urban centers has become increasingly complex and as a result this service is now contracted out;
  - General Safety Practices –efforts to improve employee safety have resulted in more time consuming approaches to work.
- Rising fuel prices – information obtained from Statistics Canada indicates regular gasoline prices in Winnipeg have increased 32% from March 2009 to March 2012 and diesel prices have increased 52% for the same timeframe;
- More expensive safety clothing - Flame Resistant, High Visibility and Asbestos protection;
- Compliance with environmental legislation has increased costs for environmental management including employee training, spill response exercises, spill response kits, and outfitting facilities with environmental supplies.

PUB/CENTRA II-146

Reference: PUB/Centra I-16(a)

b) Since Centra forecasts declining volumes due to continuing conservation efforts in its rate applications, please explain why this is a financial risk to Centra.

ANSWER:

In recent years, Centra has experienced greater actual natural gas conservation than forecast, which has reduced sales volumes and corresponding revenues. In years where Centra does not file a General Rate Application, it is exposed to greater risk of reduced revenues, as existing rates are based on a load forecast that may not reflect actual conservation experience.

PUB/CENTRA II-147

Reference: PUB/Centra I-18

a) Please provide the activity hours, activity charges, primary costs, and total costs for the Natural Gas Operations Quality Assessment Process for each year since its inception in 2008/09.

ANSWER:

Please see attached schedule.

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS, OVERHEADS AND HOURS

($000's)

Program	2008/09 Actual Primary	2008/09 Actual Activity Charges	2008/09 Actual Overhead	2008/09 Actual Program Costs	2008/09 Actual Activity Hours	2009/10 Actual Primary	2009/10 Actual Activity Charges	2009/10 Actual Overhead	2009/10 Actual Program Costs	2009/10 Actual Activity Hours	2010/11 Actual Primary	2010/11 Actual Activity Charges	2010/11 Actual Overhead	2010/11 Actual Program Costs	2010/11 Actual Activity Hours
Quality Assessment	$ -	$ 203	$ 55	$ 258	2,693	$ 11	$ 371	$ 89	$ 470	4,623	$ 14	$ 543	$ 92	$ 649	6,345

($000's)

Program	2011/12 Actual Primary	2011/12 Actual Activity Charges	2011/12 Actual Overhead	2011/12 Actual Program Costs	2011/12 Actual Activity Hours	2012/13 Forecast Primary	2012/13 Forecast Activity Charges	2012/13 Forecast Overhead	2012/13 Forecast Program Costs	2012/13 Forecast Activity Hours	2013/14 Test Year Primary	2013/14 Test Year Activity Charges	2013/14 Test Year Overhead	2013/14 Test Year Program Costs	2013/14 Test Year Activity Hours
Quality Assessment	$ -	$ 574	$ 98	$ 671	6,040	$ 15	$ 440	$ 110	$ 565	6,210	$ 15	$ 449	$ 112	$ 576	6,210

PUB/CENTRA II-147

Reference: PUB/Centra I-18

b) In light of Centra's cost containment efforts, please explain why Donations, Grants, and Sponsorships were materially higher in 2009/10 and 2010/11 than the approved amounts and why the amounts in 2011/12 increased even further.

ANSWER:

The approved amounts for 2009/10 and 2010/11 did not include Centra's portion of the Corporation's cost to match employee funded donations, which are reflected in the actual for these years. The 2011/12 forecast included this additional cost.

In addition, actual for all the above noted years, and forecast for 2012/13, included increased costs for the Neighbors Helping Neighbors program in both the City of Winnipeg and in rural Manitoba.

PUB/CENTRA II-148

Reference: PUB/Centra 19

a) Please re-file the schedule reflecting the Furnace Replacement Program in the Forecast Year and Test Year revenue requirements instead of as a reduction in revenue.

ANSWER:

The table included below reflects the Furnace Replacement Program in the Forecast Year and Test Year revenue requirements.

($000's)

	Last Approved [1]	2012/13 Forecast Year	Net Change from Last Approved	Net Change % from Last Approved	Last Approved [1]	2013/14 Test Year	Net Change from Last Approved	Net Change % from Last Approved
Revenue Requirement:								
Cost of Gas	331,442	175,576	(155,866)	-47%	331,442	168,279	(163,163)	-49%
Other Income	(2,026)	(1,705)	321	-16%	(2,026)	(1,866)	160	-8%
Operating & Administrative	60,343	67,300	6,957	12%	60,343	68,800	8,457	14%
Depreciation & Amortization	27,367	27,620	253	1%	27,367	30,091	2,724	10%
Furnace Replacement Program	3,800	3,800	-	-	3,800	3,800	-	-
Capital and Other Taxes	23,940	18,334	(5,606)	-23%	23,940	18,750	(5,190)	-22%
Finance Expense	19,105	17,901	(1,204)	-6%	19,105	17,296	(1,809)	-9%
Corporate Allocation	12,000	12,000	-	-	12,000	12,000	-	-
Net Income	2,505	1,562	(943)	-38%	2,505	4,821	2,316	92%
Revenue Requirement from Gas Rates	478,476	322,388	(156,088)	-33%	478,476	321,971	(156,505)	-33%
Revenue on existing base rates		322,388				316,226		
Non Gas Revenue Deficiency		-				5,745		
Rate Base:								
Gas Plant in Service	634,052	658,683	24,631	4%	634,052	681,747	47,695	8%
Accumulated Depreciation	(229,807)	(232,935)	(3,128)	1%	(229,807)	(241,999)	(12,192)	5%
Net Plant	404,245	425,747	21,503	5%	404,245	439,749	35,503	9%
Contributions in Aid of Construction	(50,956)	(51,931)	(975)	2%	(50,956)	(53,062)	(2,106)	4%
Working Capital Allowance	132,576	105,031	(27,545)	-21%	132,576	102,867	(29,709)	-22%
Total Rate Base	485,864	478,847	(7,017)	-1%	485,864	489,553	3,688	1%

[1] Last approved is comprised of 2010/11 Test Year approved

PUB/CENTRA II-148

Reference: PUB/Centra 19

b) Please explain how Centra is accounting for the FRP expenditures and the deferred balance in its financial forecast and financial statements.

ANSWER:

Centra allocates $3.8 million of revenue annually to the FRP deferral account. Carrying costs are added using the short term borrowing rate, including the parental guarantee fee. As lower income customers utilize the program, the liability is drawn down by the amount of the subsidy to each customer. The FRP deferral account is included in accounts payable and accrued liabilities on Centra's financial statements.

On a forecast basis, the process is essentially the same. Forecasted rather than actual expenditures draw down the liability.

PUB/CENTRA II-149

Reference: PUB/Centra I-20 – Corporate Allocations & Adjustments, Cost Driver Change

a) Please indicate how the change from the number of bills cost driver to the number of customers cost driver has impacted the costs being allocated to Centra in each of the years 2011/12, 2012/13, and 2013/14.

ANSWER:

The change from the number of bills cost driver to the number of customers cost driver occurred at the beginning of 2013/14.

Please see the attached schedule for the impact of costs being allocated to Centra.

($000's)

	2011/12[1]		2012/13[1]		2013/14	
	% to Centra	Actual	% to Centra	Forecast	% to Centra	Test Year
Number of Bills	35%	$ 3,131,742	35%	$ 3,195,165	35%	$ 3,211,784
Number of Customers	N/A	N/A	N/A	N/A	33%	$ 3,028,253
Reduction of Cost to Centra		N/A		N/A		$ (183,531)

(1) The change from the number of bills driver to the number of customers driver occurred in 2013/14.

PUB/CENTRA II-149

Reference: PUB/Centra I-20 – Corporate Allocations & Adjustments, Cost Driver Change

b) Please file any analysis or reports undertaken in support of this change.

ANSWER:

As noted in PUB/Centra I-20(c), it was determined that the nature of the costs contained in these types of common orders was more accurately reflected in each of the utilities through this cost driver. There were no reports undertaken in support of this change.

PUB/CENTRA II-149

Reference: PUB/Centra I-20 – Corporate Allocations & Adjustments, Cost Driver Change

c) Please provide the supporting calculations for the determination of the average salary for Administration for President & CEO, Corporate Relations, Finance & Administration, and Power Supply.

ANSWER:

Please see the schedule of supporting calculations. The average salary per EFT for Power Supply includes Trainees, which results in a lower average salary per EFT.

MANITOBA HYDRO
AVERAGE SALARY PER EFT

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Test Year
President & CEO						
Administration						
Wages (In Thousands)	3,150	3,701	3,927	4,095	4,139	4,222
EFT	26.5	29.1	31.6	32.1	31.5	31.5
Average Salary/EFT	**$ 118.753**	**$ 127.271**	**$ 124.135**	**$ 127.592**	**$ 131.531**	**$ 134.161**
Corporate Relations						
Administration						
Wages (In Thousands)	871	495	385	363	373	381
EFT	7.9	4.7	3.6	2.9	2.8	2.8
Average Salary/EFT	**$ 110.598**	**$ 104.715**	**$ 108.406**	**$ 123.827**	**$ 135.412**	**$ 138.120**
Finance & Administration						
Administration						
Wages (In Thousands)	1,713	1,839	1,735	1,674	1,790	1,826
EFT	17.9	18.4	16.3	13.4	14.0	14.0
Average Salary/EFT	**$ 95.888**	**$ 99.936**	**$ 106.539**	**$ 125.325**	**$ 127.836**	**$ 130.393**
Power Supply						
Administration						
Wages (In Thousands)	8,517	9,733	11,348	12,842	13,878	14,155
EFT	172.7	189.7	218.5	230.7	246.4	246.4
Average Salary/EFT	**$ 49.326**	**$ 51.295**	**$ 51.943**	**$ 55.666**	**$ 56.317**	**$ 57.443**

PUB/CENTRA II-150

Reference: PUB/Centra I-23(c); PUB/Centra I-41(d); 2009/10 & 2010/11 GRA Transcript p.835

a) Please reconcile the analysis provided in Exhibit #20 to the 2009/10 & 2010/11 GRA and provide supporting calculations for the current estimate in rental cost at 444 St. Mary Avenue.

ANSWER:

The following table reconciles the current rental rate for 444 St Mary Avenue as it appears in PUB/Centra I-23(c), column noted as "2013", to Exhibit 20 which was Centra's response to an undertaking in the 2009/10 & 2010/11 GRA.

444 St. Mary Ave costs	2013	Exhibit 20	Difference	
Leasehold Rentals	865	850	15	(1)
Building & Property Services	668	850	(182)	(2)
Building & Property Taxes	252		252	(2)
Parking/Utility/Other O&A		400	(400)	(3)
(in '000s)	$1 785	$2 100		
Square footage	***78 642***	***72 688***	***5 954***	(4)
Cost per square foot	***23***	***29***		

(1) The market rates for leasehold rentals have remained constant over the last three years for rental property at 444 St Mary.

(2) Exhibit 20 did not break out property taxes in the same manner as the response to PUB/Centra I-23(c).

(3) Parking information is normally not included in lease rates but is added to the lease rate as an additional cost to the tenant. This information was not available for the current estimate. Utilities and other O&A were not available for the current estimate. It is noted that these represented approximately $100,000 in Exhibit 20 and were not considered material to the cost per square foot calculation.

(4) The square footage used in Exhibit 20 was incorrect and was subsequently amended to 78,642 in PUB/MH II-151(a) of the 2010/11 & 2011/12 Electric GRA, as noted in Centra's response to PUB/Centra II-150(b).

Supporting calculations for the current estimate are based on current market information obtained by the Corporation. Lease rates for property at 444 St Mary Avenue were estimated by taking $11 per square foot for rental rates; this is on the low end of an $11 to $13 range. Building & Property Services and taxes were calculated using $8.50 and $3.20 respectively.

PUB/CENTRA II-150

Reference: PUB/Centra I-23(c); PUB/Centra I-41(d); 2009/10 & 2010/11 GRA Transcript p.835

b) Please file Exhibit #20 from the 2009/10 & 2010/11 GRA.

ANSWER:

The cost per square foot information presented in Exhibit #20 from the 2009/10 & 2010/11 GRA was updated in Manitoba Hydro's 2010/11 & 2011/12 GRA. Please see the attachment to this response, which provides Manitoba Hydro's response to Information Request PUB/MH I-151(a). Exhibit #20 was filed as an attachment to PUB/MH I-151(a) and can also be found in the attachment to this response.

PUB/MH II-151

Subject: Tab 13 Board Directives
Reference: PUB/MH I-179 (a) & (h)

a) **Please file Exhibit # 20 dated June 22, 2009 from the 2009/10 and 2010/11 Centra GRA and provide an update and reconciliation with the analysis provided at this hearing.**

ANSWER:

Please see the following attachment for a copy of Exhibit #20 from the 2009/10 & 2010/11 Centra GRA.

Please see the attached tables.

444 St. Mary Costs

(in thousands of $)	
Annual Rent	$1,064
Common Area Maintenance	724
Operations	36
Property & Business Tax	235
Annual Cost	**$2,060**
Square footage	78,642
Cost per square foot	**$26**
Cost per square foot (Exhibit #20 2009/10 Gas GRA)	**$29**

The costs presented in Exhibit 20, from the 2009/10 Gas GRA, were based upon Centra's estimate of entering into a new lease. Also, the square footage provided in this response was understated.

The costs presented in PUB/MH I-179(a) are based on the last full year of costs incurred by Manitoba Hydro to lease 444 St. Mary.

360 Portage Projected Costs - 2010/11

(in thousands of $)	
Operating & Maintenance	$3,201
Property & Business Tax	4,862
Depreciation	3,093
Interest	15,990
Projected Annual Cost	**$27,147**
Square footage	697,609
Cost per square foot	**$39**
Cost per square foot (Exhibit #20 2009/10 Gas GRA)	**$44**

The costs presented in Exhibit 20, from the 2009/10 Gas GRA, where based on the annualized amounts for 360 Portage. The principal and interest amount represented the annualized payments of a $278 million building over 60 years, which inherently includes depreciation and amortization.

The costs presented in PUB/MH I-178(a) are based on the expected costs for the 2010/11 fiscal year.

CENTRA GAS MANITOBA INC.

2009/10 & 2010/11 GENERAL RATE APPLICATION

UNDERTAKING PROVIDED BY: V. WARDEN

UNDERTAKING NO. 14 - TRANSCRIPT PAGE NO. 838:

Please provide a breakdown of the projected 2010 cost per square foot for 444 St. Mary Avenue and 360 Portage Avenue.

Below is a table containing the projected 2010 cost per square foot breakdown for 444 St. Mary Avenue and the annual projected cost for 360 Portage Avenue. Please note that the projected annual costs for 360 Portage Avenue are preliminary.

444 St. Mary Projected Costs

Rent @ $12 / sq ft	$850,000
Common Area Maintenance @ $12 / sq ft	850,000
Parking	300,000
Electric Utility	50,000
Other Operating & Maintenance	50,000
Projected Annual Cost for 2010	**$2,100,000**
Square footage	72,688
Cost per square foot	**$29**

360 Portage Projected Costs

Operating & Maintenance	$3,950,000
Property & Business Tax	6,700,000
Principal & Interest	20,000,000
Projected Annual Cost (annualized)	**$30,650,000**
Square footage	697,609
Cost per square foot	**$44**

PUB/CENTRA II-150

Reference: PUB/Centra I-23(c); PUB/Centra I-41(d); 2009/10 & 2010/11 GRA Transcript p.835

c) At the 2009/10 & 2010/11 GRA, Centra indicated that current market rates for Class A office space were $12 to $14 per square foot. Please provide the current estimate and cite the source.

ANSWER:

To clarify, the market rates of $12 to $14 per square foot as referenced in the 2009/10 & 2010/11 GRA Transcript p.835 regarding the 444 St Mary property was representative of Class B office space.

The current estimate of $11 to $13 lease rates and $11.70 Building Property Services and taxes are based on market studies conducted by various real estate brokers. The Corporation has confirmed that 444 St Mary Avenue has maintained its Class B status.

PUB/CENTRA II-150

Reference: PUB/Centra I-23(c); PUB/Centra I-41(d); 2009/10 & 2010/11 GRA Transcript p.835

d) Please provide detailed calculation of the depreciation on common assets for 2012/13 and 2013/14.

ANSWER:

Please see Centra's response to PUB/Centra II-160.

PUB/CENTRA II-151

Reference: PUB/Centra I-24(b)

a) Please provide supporting calculations and analysis for the 6.5% and 5.25% discount rates.

ANSWER:

The discount rate is determined each year in consultation with Manitoba Hydro's external actuary and auditor.

The determination of a 6.5% discount rate considered the 10 year average annual rate of return on the assets of the fund and long-term bond yields, consistent with prior years. This was considered to be reasonable given that the same discount rate was used by the CSSB at the time.

In September 2011, the Canadian Institute of Actuaries (CIA) published an education note, "*Accounting Discount Rate Assumption for Pension and Post-employment Benefit Plans".* The note provided guidance to actuaries on the determination of the accounting discount rate for defined benefit plans to improve consistency in application across the actuarial industry and to ensure compliance with CICA 3461.063 which states that "the discount rate used to determine the accrued benefit obligation shall be an interest rate determined by:

(a) Market interest rates at the measurement date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments; or

(b) The interest rate inherent in the amount at which the accrued benefit obligation could be settled.

Recognizing the new guidance provided by the CIA, Manitoba Hydro adopted Mercer Canada's PC-Bond Curve to determine its discount rate as at March 31, 2012. Mercer's approach incorporated the CIA recommended methodology and resulted in a discount rate of 5.25% based on a 14 year duration. Mercer does not provide the detailed calculations of its proprietary methodology to Centra.

PUB/CENTRA II-151

Reference: PUB/Centra I-24(b)

b) Please indicate to what extent a PFAD has been incorporated in the discount rate.

ANSWER:

The provision for adverse deviations (PfAD) was not considered in the determination of the 5.25% discount rate.

<u>PUB/CENTRA II-152</u>

Reference: PUB/Centra I-28(a)

a) Please file the terms of reference for the proposed benchmarking study for the compensation of electric-based bargaining units.

<u>ANSWER</u>:

The benchmarking study is intended to acquire compensation information for jobs related to the provision of electric service, and the comparisons will be made solely against other electric utilities. No costs associated with this study will be charged to Centra.

In addition, the terms of reference contain a provision requiring parties to maintain confidentiality.

PUB/CENTRA II-152

Reference: PUB/Centra I-28(a)

b) Please indicate whether the study is being done internally or externally, and if externally by whom.

ANSWER:

Please see Centra's response to PUB/Centra II-152(a).

PUB/CENTRA II-152

Reference: PUB/Centra I-28(a)

c) Please estimate the cost for the completion of the benchmarking study.

ANSWER:

Please see Centra's response to PUB/Centra II-152(a).

PUB/CENTRA II-153

Reference: PUB/Centra I-29(b); PUB/Centra I-131(d) Attachment 1

a) For 2012/13, please provide a detailed schedule of support costs that have been removed from activity rates and indicate whether the costs are included in the common overhead rate or as a direct allocation to Centra.

ANSWER:

Please see the table below.

Schedule of Support Costs Removed from Activity Rates for 2012/13 **($ millions)**

	Overhead			Direct Allocation			Total
		% to Centra	Allocated to Centra		% to Centra	Allocated to Centra	Allocated to Centra
Training	$ 37.3	10%	$ 3.73				$ 3.73
Division & Department Manager	30.4	10%	3.04	$ 5.6	4%	$ 0.22	3.26
Information Technology	19.5	10%	1.95	20.3	10%	2.03	3.98
Other	8.2	10%	0.82				0.82
Total	$ 95.4		$ 9.54	$ 25.9		$ 2.25	$ 11.79

PUB/CENTRA II-153

Reference: PUB/Centra I-29(b); PUB/Centra I-131(d) Attachment 1

b) Please provide detail of the common overhead pool costs for 2011/12 and 2012/13 for the change in the common overhead rate from 17% to 25%. Please break out the pool costs for 2012/13 between the costs to support the 20% common overhead rate and the 5% tool overhead rate.

ANSWER:

Please see the table below.

Overhead (000's)	2011-12 Common OH Actual	2012-13 Common OH Forecast	2012-13 Tools & Procurement Forecast	2012-13 Total OH Forecast
Corporate Services (1)	$ 34,265	$ 35,000	$ 5,000	$ 40,000
Departmental Support (2)	$ -	$ 77,000	$ -	$ 77,000
Other Costs (3)	$ 71,818	-	$ 23,000	$ 23,000
Common Overhead Pool	$ 106,083	$ 112,000	$ 28,000	$ 140,000
Total Activity	$ 622,379	$ 564,000	$ 564,000	$ 564,000
Rate	**17.00%**	**20.00%**	**5.00%**	**25.00%**

Notes:

(1) Corporate Services costs include human resources, financial sevices and safety.

(2) Departmental Support are the costs that were removed from activity rates, such as training and administrative costs.

(3) Other Costs include depreciation and operating costs on common assets, such as buildings, IT infrastructure and tools and work equipment.

PUB/CENTRA II-153

Reference: PUB/Centra I-29(b); PUB/Centra I-131(d) Attachment 1

c) Please file Appendix A, B, and C to PUB/Centra I-131(d) Attachment 1.

ANSWER:

Please see the attachment to this response.

APPENDIX A

Common Overhead, Tool & Procurement and Third Party Billing Rate Calculations

Tool & Procurement Rate – A Tools & Procurement rate of 5% will be charged to capital networks and operating orders. This rate recovers costs of small tools, such as personal computers and costs associated with the procurement process. These costs were previously charged through activity or overhead rates and will be recovered as a percentage add-on to activity charges

Common Overhead Rate – The common overhead rate recovers corporate service and departmental support costs such as HR and IT, that are required by the corporation to support is various activities. These costs were previously charged through activity or overhead rates and will be recovered as a percentage add-on to activity charges.

Third Party Billing Overhead – General and administrative costs are required by the corporation to support its various activities. Although these costs will no longer be allocated to capital networks and operating orders through activity or general overhead rates, they should continue to be applied to third party billings for cost recovery purposes.

Description	2012/13 Tool & Procurement (millions)	2012/13 Common Overhead (millions)	2012/13 3rd Party Billing Overhead (millions)
Corporate Governance: - Executive, general counsel, corporate accounting	0	0	29
Corporate Infrastructure: - Buildings, IT & communication infrastructure (operating, finance expense, depreciation and property taxes)	0	0	130
Corporate Services: - Finance, HR, Safety	0	35	0
Departmental Support: - Division & Department Managers, administrative staff, training	0	77	0
Tools & Procurement: - Technical design and mapping software, PC's, accounts payable, purchasing & moves	28	0	0
Total Expenses	28	112	159

Total Activity	564	564	564

Rate (Rounded)	5%	20%	28%

APPENDIX B

General Material & Serialized Equipment Overhead Calculations

Material overhead represents the costs and salvage rates for materials managed by the Stores department. These costs include operating costs and salvage recovery credits. Serialized equipment includes items such as large oil filled equipment and switches that can be tracked by serial number. They are purchased to asset accounts resulting in a different costing structure.

Stores Overhead Rate Calculation
(in millions)

General Material Overhead Calculation	2013 Estimated	2014 Estimated
COSTS - Salaries, wages, tools, equipment, etc. related to:		
General Material Issues	5.7	5.3
General Material Salvage	1.0	0.6
Gas Material Issues	0.3	0.3
COSTS TO BE RECOVERED	7.0	6.2
RECOVERY: (items expected to be issued by stores)		
General Material Issues, Salvage and Gas Issues	72.1	72.1
General Material Overhead Rate (Rounded)	10%	9%

Serialized Equipment Overhead Calculation	2013 Estimated	2014 Estimated
COSTS - Salaries, wages, tools, equipment, etc. related to:		
Serialized Equipment Issues	0.4	0.4
Serialized Equipment Salvage	0.3	0.3
COSTS TO BE RECOVERED	0.7	0.7
RECOVERY: (items expected to be issued by stores)		
Serialized Equipment Issues and Salvage	17.5	17.5
Serialized Equipment Overhead Rate (Rounded)	4%	4%

APPENDIX C

Employee Benefit Rates

Employee benefits consist primarily of indirect and non-cash compensation paid employees. Some benefits are mandated by law (such as Canadian Pension Plan, unemployment compensation, payroll taxes, and workers compensation), and others vary from firm to firm or industry to industry (such as pension, disability insurance, and dental) in accordance with negotiated bargaining unit settlements.

Employee benefit costs are recovered by charging to department cost centers based upon a percentage add-on applied to wages and salaries. Annually, an employee benefit study is performed to recalculate the employee benefit rate based on current expectations. The employee benefit rate is reviewed against previous years and year-to-date actual results. The employee benefit study ensures that the benefit costs are fully allocated.

Employee Benefits Pool	2012 Actuals	2013 Proposed[1]	Variance	% Variance	Variance Explanation
Pension Plan	30.7	32.5	1.8	5.9%	Higher current service forecasted due to higher pensionable earnings as a result of escalating wages & salaries.
Past Service Pension	0.5	5.6	5.1	1020.0%	Increase is due to increased amortization of losses experienced since 2008.
Legislated Deductions	31.8	32.6	0.8	2.5%	
Employee & Family Health Plans	17.4	18.5	1.1	6.3%	Mainly due to projected estimates in Extended Health and Drug Plans from Blue Cross and Claims Secure.
Post Employment Benefits	13.0	14.3	1.3	10.0%	Mainly due to Increase due to amortization of the impact of the lowering of the discount rate of approx $900 K for 3 years.
Vacation	13.7	11.7	(2.0)	(14.6%)	Vac. payouts in 2012 were approx $2.5 M higher than in prior years in addition to the impact of lowering the discount rate on expense. 2013 forecast includes average expected vacation payouts.
Maternity & Disability Insurance	5.3	5.8	0.5	9.4%	
Employee Benefits Pool	$ 112	$ 121	8.6	7.7%	
Total Wages & Salaries	$ 446	$ 451	5.0	1.1%	EFTS are expected to remain relatively flat since cost constraint measures are still to be observed. Therefore rate would be the only impact to the proposed F2013 increase. F2012 was also overinflated since it included IBEW retro pay.
Total Overtime	$ 56	$ 53	(3.0)	(5.4%)	Fiscal 2012 was an abnormal year since it included IBEW retro pay and a higher amount of capital work in CS&D which is not expected in Fiscal 2013.
True Rate - Straight Time	24.83%	26.48%			
Rate (Rounded)	25%	26%			The increase in the employee benefit rate is due primarily to the increase in Past Service Pension costs as a result of the amortization of investment losses experienced since 2008 as well as higher current service pension costs due to higher pensionable earnings resulting from escalating wages & salaries

PUB/CENTRA II-154

Reference: PUB/Centra I-30(b)

a) Please explain why Centra has not harmonized the accounting policy in this application similar to other IFRS "related" overhead accounting changes that Centra has proposed be made.

ANSWER:

As indicated in the response to PUB/Centra I-31(a), Centra revised its overhead capitalization practices to ensure that Centra's capitalization practices were consistent and comparable with those of other Canadian utilities under CGAAP. Such revisions were recognized as changes in the estimate of overhead attributable to the construction of property, plant & equipment and as such, were applied on a prospective basis; similar to the accounting treatment applied in the electric operations.

The potential accounting change to begin capitalizing the labour charges for meter exchange activities upon transition to IFRS is not driven by the need to be consistent and comparable with industry practices under CGAAP, but as indicated in the response to PUB/Centra I-30(b), may be undertaken to harmonize the accounting practices of a parent and its subsidiaries upon transition to IFRS. Since this change would be part of the requirements of adopting IFRS and would not otherwise be implemented by the Corporation under CGAAP, the Corporation may consider the change upon transition to IFRS.

PUB/CENTRA II-154

Reference: PUB/Centra I-30(b)

b) Please file any internal analysis or position papers related to the capitalization of labour costs in order to harmonize the policy with Manitoba Hydro.

ANSWER:

The potential change with respect to the capitalization of labour costs on meter exchanges for Centra is not incorporated into the test years for this rate application and as indicated in the response to PUB/Centra I-30(b), is in the preliminary review stage as an item requiring harmonization with the accounting policies of Manitoba Hydro's electric operations. As such, no position papers exist at this time. In advance of the final determination of the accounting treatment of labour charges for meter exchange activities upon adoption of IFRS, a simplifying assumption has been made in CGM12 that the treatment used in electric operations would be applied to gas operations. This assumption is subject to review.

PUB/CENTRA II-154

Reference: PUB/Centra I-30(b)

c) Please indicate the financial impact of harmonizing the capitalization policy by capitalizing labour costs related to exchange activities in 2013/14.

ANSWER:

As indicated in Centra's response to PUB/Centra II-154(a), Centra is still considering this potential change and has not quantified the full financial impacts of this change, including any changes in depreciation and the potential for retrospective re-statement of this change in accounting policy if it were made in advance of IFRS implementation.

PUB/CENTRA II-154

Reference: PUB/Centra I-30(b)

d) Please indicate all accounting policies that Centra has identified will need to be harmonized and the financial implications of such harmonization.

ANSWER:

Please see Centra's response to PUB/Centra I-7(b) which identifies all accounting changes implemented to date and potential accounting changes required (including those to be harmonized) upon transition to IFRS. To date, the Corporation is not aware of any other accounting policies not already identified in the response to PUB/Centra I-7(b) that will have to be harmonized upon transition to IFRS.

PUB/CENTRA II-155

Reference: PUB/Centra I-33

a) Please quantify the amounts of building and facility OM&A costs that were recovered in 2010/11 and 2011/12 through overhead and activity rates.

ANSWER:

Please see Centra's response to PUB/Centra II-157.

PUB/CENTRA II-155

Reference: PUB/Centra I-33

b) Please describe and provide the detailed calculation for the head office credit and how it is applied.

ANSWER:

As explained in PUB/Centra I-22, the head office credit was determined to effectively maintain the total building cost allocation to Centra as if the 444 St. Mary Ave and other leased administrative buildings continue to exist.

During 2006/07 and 2007/08, 360 Portage was still under construction and none of these costs were allocated to Centra.

During 2008/09 and 2009/10, when Manitoba Hydro staff were relocated from previously leased administrative buildings to locations at 360 Portage and also 820 Taylor, building costs allocated to Centra were allocated through overhead during this transition period. During this time, Centra overhead rates, with respect to building space costs, were not changed. Not including the full space cost in the overhead rate ensured that the overall level of costs remained the same as if the 444 St. Mary Ave and other leased administrative buildings continued to exist through the transition period and in effect resulted in a reduction to the overall space cost that normally would have been allocated.

In the period post construction, a credit has been applied in the shared cost allocation to Centra to effectively maintain the building cost allocation as if the 444 St. Mary Ave and other leased administrative buildings continue to exist. These changes are reflected in the table below.

Schedule of Administrative Buildings (Space Costs) - 2006/07 to 2013/14 **($ millions)**

	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Test Year
Total Costs	$ 30.6	$ 33.2	$ 52.4	$ 59.7	$ 59.3	$ 58.6	$ 59.3	$ 60.0
Allocation % *(rounded)*	11%	10%	10%	10%	10%	10%	10%	10%
Allocation	3.4	3.4	5.2	6.0	5.8	5.7	5.9	6.0
Impact of not changing overhead rates	-	-	(1.9)	(2.7)	-	-	-	-
Head Office Credit	-	-	-	-	(2.2)	(2.2)	(2.2)	(2.2)
Allocation to Centra[1]	$ 3.4	$ 3.4	$ 3.3	$ 3.3	$ 3.6	$ 3.5	$ 3.7	$ 3.8

[1] Annualized Compound Growth Rate	1.7%

PUB/CENTRA II-155

Reference: PUB/Centra I-33

c) Please quantify the amount of IT infrastructure support recovered in 2010/11 and 2011/12 through overhead and activity rates.

ANSWER

Please see schedule below.

CENTRA GAS MANITOBA INC.
2013/14 General Rate Application
IT Infrastructure in OH and Activity Rates

($000's)

($000's)	2010/11(1) Actual	2011/12(1) Actual	2012/13(2) Forecast	2013/14(2) Forecast
IT Infrastructure Support	$ 3,129	$ 3,091	$ 2,937	$ 2,996

(1) IT infrastructure support costs were recovered through overhead and activity rates and embedded in operating programs.

(2) IT infrastructure support costs are allocated directly to Centra through Corporate Allocations and Adjustments.

PUB/CENTRA II-156

Reference: PUB/Centra I-33; PUB/Centra I-34(c) - Building Costs

a) Please indicate the detail by component of space cost allocations totaling $3.7 million in 2011/12 and $3.8 million in 2013/14 are included in the costs allocated to Centra.

ANSWER:

Please see Centra's response to PUB/Centra II-157 which identifies the related costs by component for space costs.

PUB/CENTRA II-156

Reference: PUB/Centra I-33; PUB/Centra I-34(c) - Building Costs

b) Please demonstrate how the credit related to the head office has been applied to ensure that occupancy costs are not overstated.

ANSWER:

Please see the response to PUB/Centra II-155(b) for an explanation of the head office credit and the allocation to Centra.

PUB/CENTRA II-157

Reference: PUB/Centra I-34 – Common Facilities

Please provide a schedule of the related costs by component related to common facilities and the portion of each allocated to Centra.

ANSWER:

Please see the schedule below from 2006/07 to 2013/14 of the related costs by component related for common facilities (space costs) and the portion allocated to Centra.

Schedule by Component of Administrative Buildings (Space Costs) - 2006/07 to 2013/14 ($ millions)

	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Test Year
Operating & Maintenance	$ 16.3	$ 16.4	$ 18.1	$ 18.5	$ 18.6	$ 16.8	$ 17.1	$ 17.5
Interest	7.1	9.3	24.4	27.8	25.8	25.9	25.8	25.8
Depreciation	3.0	3.0	5.7	6.5	6.6	7.8	8.0	8.0
Property Tax	4.2	4.5	4.2	6.9	8.3	8.1	8.4	8.7
Total	$ 30.6	$ 33.2	$ 52.4	$ 59.7	$ 59.3	$ 58.6	$ 59.3	$ 60.0
Allocation to Centra	$ 3.4	$ 3.4	$ 3.3	$ 3.3	$ 3.6	$ 3.5	$ 3.7	$ 3.8
% Allocated [1]	11%	10%	6%	6%	6%	6%	6%	6%

[1] Total space costs are allocated to Centra via activity charges; in 2008/09 & 2009/10 - overhead rates were not changed with respect to building space costs to ensure that the overall level of costs remained the same as if the 444 St. Mary Ave and other leased administrative buildings continued to exist through the transition period; from 2010/11 onward - In the post construction period, a credit has been applied to reduce the cost allocation to Centra via activity charges in order to maintain the building cost allocation as if the 444 St. Mary Ave and other leased administrative buildings continue to exist.

PUB/CENTRA II-158

Reference: PUB/Centra 36 – Hearing Scope

Please elaborate and discuss Centra's considerations related to policy changes if rate regulated accounting is grandfathered versus abolished.

ANSWER:

The IASB issued the exposure draft "Regulatory Deferral Accounts" on April 25, 2013. Responses to the exposure draft are due in September 2013 and a summary of the responses will be made available by the IASB in October 2013. The future actions of the IASB on this proposal will depend largely on the feedback they receive from interested parties. If a new standard is approved, the IASB is not expected to finalize the interim standard until December 2013 at the earliest.

Given that the exposure draft on the interim standard was just recently issued, Manitoba Hydro has not yet had an opportunity to complete a full assessment of the potential impacts. The Corporation's assessment of the proposed interim standard will require a review of the draft standard in detail and the validation of how the standard is to be interpreted through discussions with Manitoba Hydro's external auditor, IFRS consultant, and with other Canadian utilities. The Corporation will closely monitor the progress of the exposure draft, future communications by the IASB and from industry so as to assess the potential policy changes.

Once the Corporation is satisfied that its interpretation of the proposed standard is consistent with those of the industry, it will identify and assess potential policy changes. This assessment will take into consideration the options that may be available under the proposed standard and the potential impacts on customer rates. A full assessment is not expected to be completed until early fall 2013 once the industry has had an opportunity to assess and discuss the draft standard.

PUB/CENTRA II-159

Reference: PUB/Centra I-33; 2009/10 & 2010/11 GRA PUB/Centra 31(a) – Corporate Allocations & Adjustments

a) Please update the schedule to incorporate the years 2006/07 through 2013/14 incorporating the detail provided at the last GRA in response to PUB/Centra 31(a).

ANSWER:

Please see the schedule below.

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast ($000's)
Buildings & Facility OM&A					2,281	2,327
Head Office Credit			(274)	(240)	(240)	(240)
IT Infrastructure Support					2,937	2,996
Corporate Governance						
Executive Management		621	1,718	1,767	1,672	1,705
Employee Benefit Residuals	347	(163)	713	719	1,270	1,295
Over and Under Absorption	1,422	1,002	(497)	(405)	(1,304)	(1,330)
Other Corporate Adjustments				(123)	(57)	91
Total	1,769	1,460	1,660	1,718	6,559	6,844

Please note that prior to 2012/13, building and facility OM&A & IT infrastructure support costs were recovered through overhead and activity rates and embedded in operating programs. In 2012/13 these costs were removed from overhead and activity rates and allocated directly to Centra through Corporate Allocations and Adjustments.

PUB/CENTRA II-159 (Revised)

Reference: PUB/Centra I-33; 2009/10 & 2010/11 GRA PUB/Centra 31(a) – Corporate Allocations & Adjustments

a) Please update the schedule to incorporate the years 2006/07 through 2013/14 incorporating the detail provided at the last GRA in response to PUB/Centra 31(a).

ANSWER:

Please see the schedule below.

	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast ($000's)
Buildings & Facility OM&A							2,281	2,327
Head Office Credit					(274)	(240)	(240)	(240)
IT Infrastructure Support							2,937	2,996
Corporate Governance								
Executive Management				621	1,718	1,767	1,672	1,705
Employee Benefit Residuals	743	595	347	(163)	713	719	1,270	1,295
Over and Under Absorption	1,291	755	1,422	1,002	(497)	(405)	(1,304)	(1,330)
Other Corporate Adjustments		105				(123)	(57)	91
Total	2,035	1,455	1,769	1,460	1,660	1,718	6,559	6,844

Please note that prior to 2012/13, building and facility OM&A & IT infrastructure support costs were recovered through overhead and activity rates and embedded in operating programs. In 2012/13 these costs were removed from overhead and activity rates and allocated directly to Centra through Corporate Allocations and Adjustments.

PUB/CENTRA II-159

Reference: PUB/Centra I-33; 2009/10 & 2010/11 GRA PUB/Centra 31(a) – Corporate Allocations & Adjustments

b) Please provide a comparison between the Corporate Allocation & Adjustments indicated in 2009/10 & 2010/11 GRA PUB/Centra 31(a) for the 2009/10 and 2010/11 Test Years with those actually incurred for those years and provide explanations for the variance.

ANSWER:

($000's)

	2009/10 Forecast	2009/10 Actual	Variance	Reference	2010/11 Forecast	2010/11 Actual	Variance	Reference
Head Office Credit						(274)	(274)	*4*
Corporate Governance								
Executive Management		621	621	*1*		1,718	1,718	*5*
Employee Benefit Residuals	578	(163)	(741)	*2*	590	713	123	*2*
Over and Under Absorption	(708)	1,002	1,710	*3*	(1,303)	(497)	806	*3*
Total	(130)	1,460	1,590		(713)	1,660	2,373	

Explanations for variances are provided below.

1. Executive management costs were previously forecasted to be allocated to Centra through overhead. As a result of changes in Centra's costing methodology, actual Executive management costs were removed from overhead and allocated directly to Centra through corporate allocations and adjustments.
2. This amount represents benefit costs not allocated to the gas and electric utilities through the approved benefit rate and can fluctuate from forecast due to variability of benefit costs.

3. This amount represents department costs not allocated to the gas and electric utilities through activity charges and can fluctuate from forecast due to variability of department costs and hours charged to programs and projects.
4. A head office OM&A credit was applied to actuals to ensure that no incremental costs of the new head office building were allocated to Centra as per Order 128/09 and 99/07.
5. Executive management costs and various corporate department costs were previously forecasted to be allocated to Centra through overhead. As a result of changes in Centra's costing methodology, these actual costs were removed from overhead and allocated directly to Centra through corporate allocations and adjustments.

PUB/CENTRA II-160

Reference: PUB/Centra I-41 - Common Assets

Please provide a detailed calculation of the depreciation on common assets for 2012/13 & 2013/14.

ANSWER:

Centra program costs consist of activity charges, primary costs and overhead. Prior to 2010/11, activity charges and overhead amounts included depreciation, interest and taxes on common assets. For reporting purposes, these amounts are removed from the Centra Operating & Administrative Expenses and reclassified into their respective categories on the Centra income statement. In 2012/13 depreciation on common infrastructure assets was removed from Centra programs and allocated directly to the Centra income statement.

The following schedule details the depreciation on common assets as it relates to Centra. Please refer to PUB/Centra I-22(b) for further information on the Head Office Credit.

Centra Gas Manitoba Inc.
2013/14 General Rate Application

PUB/Centra II-160

Depreciation on Common Assets

	2012/13 Forecast	2013/14 Test Year
Activity		
Activity Charges ($000's)	$ 48,101	$ 49,063
% of Activity Charges representing Common Asset Depreciation	1.25%	1.25%
Depreciation Allocated to Centra ($000's)	$ 601	$ 613
Common Overhead		
Common Overhead ($000's)	$ 12,065	$ 12,307
% of the Common Overhead Pool representing Common Asset Depreciation	12.70%	12.70%
Depreciation Allocated to Centra ($000's)	$ 1,532	$ 1,563
Operations & Administrative Buildings - Rural		
Depreciation Expense ($000's)	$ 2,130	$ 2,151
Gas Split	10%	10%
Depreciation Allocated to Centra ($000's)	$ 213	$ 215
Operations & Administrative Buildings - City		
Depreciation Expense ($000's)	$ 1,620	$ 1,636
Gas Split	10%	10%
Depreciation Allocated to Centra ($000's)	$ 162	$ 164
820 Taylor		
Depreciation Expense ($000's)	$ 580	$ 586
Gas Split	10%	10%
Depreciation Allocated to Centra ($000's)	$ 58	$ 59
New Head Office		
Depreciation Expense ($000's)	$ 3,628	$ 3,701
Gas Split	10%	10%
Depreciation Allocated to Centra ($000's)	$ 363	$ 370
Communications		
Depreciation Expense ($000's)	$ 2,416	$ 2,419
Gas Split	10%	10%
Depreciation Allocated to Centra ($000's)	$ 241	$ 242
Office Furniture & Equipment		
Depreciation Expense ($000's)	$ 1,410	$ 1,413
Gas Split	10%	10%
Depreciation Allocated to Centra ($000's)	$ 141	$ 142
IT Infastructure		
Depreciation Expense ($000's)	$ 13,695	$ 13,807
Gas Split	10%	10%
Depreciation Allocated to Centra ($000's)	$ 1,369	$ 1,380

Centra Gas Manitoba Inc.
2013/14 General Rate Application

PUB/Centra II-160

Depreciation on Common Assets

	2012/13 Forecast	2013/14 Test Year
Computer Development (Centra)		
Depreciation Expense ($000's)	$ 125	$ 126
Gas Split	100%	100%
Depreciation Allocated to Centra ($000's)	$ 125	$ 126
Customer Telephone Integration (Centra)		
Depreciation Expense ($000's)	$ 12	$ 12
Gas Split	100%	100%
Depreciation Allocated to Centra ($000's)	$ 12	$ 12
Banner		
Depreciation Expense ($000's)	$ 2,206	$ 2,223
Gas Split	33%	33%
Depreciation Allocated to Centra ($000's)	$ 730	$ 735
WebTrader		
Depreciation Expense ($000's)	$ 197	$ 199
Gas Split	32%	32%
Depreciation Allocated to Centra ($000's)	$ 63	$ 64
DSM Tracking		
Depreciation Expense ($000's)	$ 72	$ 73
Gas Split	20%	20%
Depreciation Allocated to Centra ($000's)	$ 14	$ 15
Total Depreciation on Common Assets Allocated to Centra ($000's)	$ 5,625	$ 5,700
Less amount transferred from Centra to Manitoba Hydro	(978)	(839)
Less amount for Head Office Credit	(240)	(240)
Net Depreciation on Common Assets ($000's)	$ 4,407	$ 4,621

PUB/CENTRA II-161

Reference: PUB/Centra I-43; 2009/10 & 2010/11 GRA PUB/Centra I-49 – Stand-Alone Credit Rating

Please explain the factors that have changed since Centra's assessment of its stand-alone credit rating at March 31, 2009 of BBB- which support Centra's current assessment that its capital structure is insufficient to support an investment grade rating.

ANSWER:

Centra has defined its "stand-alone" credit rating to be Centra's rating if it were an independent entity, unaffiliated with either Manitoba Hydro or the Province of Manitoba. As this is a hypothetical situation, a definitive stand-alone credit rating assessment (along with associated financing terms) was, and is not available.

At March 31, 2009, in response to PUB/Centra I - 49 (a) from the 2009/10 & 2010/11 Gas GRA, Centra estimated that:

> "Based on the most recent financial statements, it is anticipated that Centra would place near the BBB- bond rating category on a stand-alone basis."

Centra had not assessed its stand-alone credit rating to be BBB- (which is the lowest level for an investment grade rating). Rather, given the hypothetical nature of the estimate, Centra stated that its rating would be "near" the BBB- bond rating category.

Since March 2009, the financial markets have continued to show ongoing volatility, with numerous governments and utilities experiencing increased credit rating agency scrutiny and downward rating pressure. The assessment of a Centra stand-alone credit rating and the associated financing terms remains hypothetical and uncertain. From the current proceeding, in response to PUB/Centra I-43(a) Centra stated that

> "On a stand-alone basis, Centra's capital structure may not be sufficient to support an investment grade credit rating. As such, it is unclear what liquidity, interest rates and financing terms would be available to Centra as a stand-alone entity."

PUB/CENTRA II-162

Reference: PUB/Centra I-50

Please explain how Centra will implement or meet its Target Adjustments on Capital Expenditures.

ANSWER:

Centra controls and manages its overall capital expenditure forecast through reviews of its capital expenditures and individual projects on an ongoing basis. Individual projects are reviewed for their requirement and adjusted or deferred as appropriate on the basis of safety, system reliability, customer load growth, environmental sustainability and efficiency of operations. Varying methods of prioritization are used by the business units to assist in making decisions for the allocation of capital dollars and resources to meet bottom line approved forecast totals.

PUB/CENTRA II-163

Reference: PUB/Centra I-53 (a)

a) Please explain the reasons for the reduction in DSM spending by $4.2 million or (21%) in 2012/13 and $4 million or (20%) in 2013/14 including the rationale for reduced spending on residential home insulation program, commercial window and insulation program and customer service initiatives, support and contingency.

ANSWER:

Overall, planned DSM spending for 2012/13 and 2013/14 was adjusted based on revised program participation forecasts reflecting actual program activity to date, and adjustments to the cost allocations of combined electric/natural gas programs.

The reduction in planned DSM spending for the Residential Home Insulation Program is primarily due to increasingly smaller projects being undertaken per home resulting in an overall reduction in forecast incentive payments. Customer participation forecasts for the Commercial Windows, Commercial Insulation and Bioenergy Programs were reduced to reflect trends in program activity to date, resulting in lower projected spending.

The reduction in planned DSM spending on the Customer Service Initiatives, Support and Contingency category is due to primarily to a reduction in planned contingency dollars. Near term program requirements are generally better known, reducing the requirement for dollars to be set aside for contingency.

PUB/CENTRA II-163

Reference: PUB/Centra I-53 (a)

b) Please file all supporting tables and schedules detailing the 15-year spending plan envisioned in the 2013-2016 Power Smart Plan. If not available, please explain the rationale for shortening the planning horizon for DSM from prior Power Smart Plans.

ANSWER:

The 2013-2016 Power Smart Plan was created in consultation with the Province with a shortened planning period and a focus on DSM costs and savings. Supporting documentation is currently being updated; activity forecast for the period extending beyond 2016 is not anticipated to be materially different from that presented in the 2011 Power Smart Plan.

PUB/CENTRA II-164

Reference: PUB/Centra I-53(a); 2013-2016 Power Smart Plan Page 2 - Utility Costs

Please extend the table in PUB/Centra I-53(a) comparing the DSM spending forecasts from the 2011 Power Smart Plan and the 2013-2016 Power Smart Plan to include the years 2014/15 and 2015/16.

ANSWER:

Please see the table below.

	(in $1000's)							
	2012/13		2013/14		2014/15		2015/16	
	2011 PS Plan (2011$)	Updated (2012$)	2011 PS Plan (2011$)	Updated (2012$)	2011 PS Plan (2011$)	Updated (2012$)	2011 PS Plan (2011$)	Updated (2012$)
RESIDENTIAL								
New Home Program	96	0	107	0	118	0	128	0
Lower Income:								
Power Smart	*692*	*760*	*686*	*744*	*532*	*730*	*447*	*647*
Furnace Replacement Program	*2,330*	*2,378*	*2,330*	*2,378*	*1,818*	*2,378*	*1,528*	*2,205*
Apportioned Affordable Energy Fund	*3,219*	*3,075*	*3,207*	*3,054*	*769*	*3,036*	*0*	*2,753*
Lower Income Total	6,242	6,213	6,223	6,177	3,120	6,144	1,974	5,606
Home Insulation Program	2,600	1,697	2,538	1,688	2,478	1,685	2,419	1,719
Water and Energy Saver Program	644	804	637	804	628	804	0	0
RESIDENTIAL TOTAL	9,582	8,714	9,504	8,669	6,343	8,632	4,522	7,324
COMMERCIAL								
Commercial Custom Measures Program	92	141	99	141	99	141	99	141
Commercial Windows Program	503	438	503	422	447	380	447	196
Commercial Insulation Program	3,373	1,613	3,373	1,435	2,777	1,291	2,778	951
Commercial New Construction Program	248	569	239	440	269	529	304	648
Commercial Building Optimization Program	314	255	335	193	335	214	335	214
Internal Retrofit Program	0	53	0	0	0	0	0	0
Commercial Kitchen Appliance Program	79	38	91	88	102	102	113	105
CO2 Sensors	64	58	66	56	68	58	70	59
Commercial Rinse & Save Program	2	0	0	0	0	0	0	0
Commercial Water Heater Program	91	0	97	0	106	0	120	0
Commercial Boiler Program	804	1,025	816	543	768	516	3	7
COMMERCIAL TOTAL	5,573	4,192	5,619	3,317	4,971	3,230	4,270	2,320
INDUSTRIAL								
Industrial Natural Gas Optimization Program	923	770	763	770	763	640	763	640
INDUSTRIAL TOTAL	923	770	763	770	763	640	763	640
EFFICIENCY PROGRAMS SUBTOTAL	16,077	13,676	15,885	12,756	12,077	12,503	9,555	10,285
CUSTOMER SELF-GENERATION								
BioEnergy Optimization Program	572	139	30	221	96	43	543	279
	572	139	30	221	96	43	543	279
PROGRAMS SUBTOTAL	16,649	13,815	15,915	12,977	12,173	12,546	10,097	10,564
CUSTOMER SERVICE INITIATIVES, SUPPORT AND CONTINGENCY	3,551	2,128	3,410	2,354	3,267	2,407	3,179	2,474
GRAND TOTAL	20,200	15,943	19,325	15,332	15,440	14,953	13,277	13,038

PUB/CENTRA II-165

Reference: PUB/Centra I-53(a); Appendix 7.1 2011 Power Smart Plan Page 26 - Bill Reductions

a) Please provide a schedule detailing the annual and cumulative bill reductions for each natural gas DSM program for 2013/14 to 2015/16.

ANSWER:

The following table presents the annual and cumulative bill reductions for each natural gas DSM program for the period of 2013/14 to 2015/16.

	2013/14	2014/15	2015/16	Cumulative
RESIDENTIAL	**(000's $)**	**(000's $)**	**(000's $)**	**(000's $)**
Incentive Based				
Home Insulation Program	$302	$624	$950	$1,877
Water and Energy Saver Program	$244	$511	$525	$1,280
Lower Income Energy Efficiency Program	$361	$750	$1,152	$2,263
Subtotal	**$907**	**$1,885**	**$2,627**	**$5,420**
Customer Service Initiatives / Financial Loan Programs				
Power Smart Residential Loan	$103	$216	$333	$652
Residential Earth Power Loan	$34	$71	$112	$217
Power Smart PAYS Financing	$17	$35	$55	$107
Subtotal	**$154**	**$322**	**$499**	**$975**
COMMERCIAL				
Incentive Based				
Commercial Custom Measures Program	$26	$56	$87	$169
Commercial Windows Program	$90	$179	$235	$504
Commercial Refrigeration Program	$10	$21	$34	$65
Commercial Insulation Program	$245	$489	$678	$1,412
New Buildings Program	$208	$455	$734	$1,397
Commercial Building Optimization Program	$43	$100	$161	$304
Commercial Kitchen Appliance Program	$63	$140	$223	$427
CO2 Sensors	$24	$55	$93	$172
Commercial Boiler Program	$75	$163	$219	$457
Subtotal	**$785**	**$1,659**	**$2,463**	**$4,907**
Customer Service Initiatives / Financial Loan Programs				
Power Smart for Business PAYS Financing	$4	$9	$12	$26
Subtotal	**$4**	**$9**	**$12**	**$26**
INDUSTRIAL				
Industrial Natural Gas Optimization Program	$337	$634	$946	$1,917
Subtotal	**$337**	**$634**	**$946**	**$1,917**
LOAD DISPLACEMENT & ALTERNATIVE ENERGY				
BioEnergy Optimization Program	$142	$157	$379	$678
Subtotal	**$142**	**$157**	**$379**	**$678**
LESS: INTERACTIVE EFFECTS **Subtotal**	**-$345**	**-$397**	**-$444**	**-$1,186**
Grand Total	**$1,985**	**$4,270**	**$6,482**	**$12,737**

PUB/CENTRA II-165

Reference: PUB/Centra I-53(a); Appendix 7.1 2011 Power Smart Plan Page 26 - Bill Reductions

b) Please provide the same detail in (a) for the 15 year time horizon and compare that with what was estimated in the 2011 plan.

ANSWER:

Please see Centra's response to PUB/Centra II-163(b).

PUB/CENTRA II-165

Reference: **PUB/Centra I-53(a); Appendix 7.1 2011 Power Smart Plan Page 26 - Bill Reductions**

c) Please provide calculations to support the estimated bill reductions for the top three natural gas DSM programs.

ANSWER:

Please see Centra's response to PUB/Centra I–58(a).

PUB/CENTRA II-166

Reference: PUB/Centra I-53(a) Page 7 - Metrics

Please provide a schedule for each natural gas DSM program detailing the current metrics for Total Resource Cost, Societal Cost, Rate Impact Measure, Levelized Utility Cost and Customer Simple Payback, and compare with the metrics in the 2011 Power Smart Plan.

ANSWER:

Please see Centra's response to PUB/Centra II-163(b). Cost effectiveness metrics are currently being updated but are not anticipated to be materially different from those presented in the 2011 Power Smart Plan.

PUB/CENTRA II-167

Reference: PUB/Centra I-53(a), PUB/Centra I-55(a)

Please update the response to PUB/Centra I-55(a) to include the years 2014/15 and 2015/16 as well as any updates related to the 2013-2016 Power Smart Plan.

ANSWER:

Please see the table below.

Expenditure Breakdown (1000s)

	2010/11- Actual			2011/12 - Actual			2012/13 - Forecast			2013/14 - Forecast			2014/15 - Forecast			2015/16 - Forecast		
	(nominal $)			(nominal $)			(2012$)			(2012$)			(2012$)			(2012$)		
	Total	Internal	External	Total	Internal	External	Total	Internal	External	Total	Internal	External	Total	Internal	External	Total	Internal	External
RESIDENTIAL																		
New Home Program	$108	-	$108	$64	-	$64	-	-	-	-	-	-	-	-	-	-	-	-
Home Insulation Program	$2,230	$337	$1,893	$2,104	$324	$1,780	$1,697	$223	$1,474	$1,688	$222	$1,466	$1,685	$222	$1,463	$1,719	$226	$1,493
Water and Energy Saver Program	$686	$120	$566	$1,024	$172	$853	$804	$107	$697	$804	$107	$697	$804	$107	$697	-	-	-
Lower Income Energy Efficiency Program	$791	$181	$610	$822	$240	$582	$760	$133	$627	$744	$131	$614	$730	$128	$602	$647	$114	$534
	$3,815	$638	$3,178	$4,014	$736	$3,279	$3,261	$463	$2,797	$3,236	$460	$2,777	$3,218	$457	$2,762	$2,366	$340	$2,026
COMMERCIAL																		
Commercial Custom Measures Program	$154	$58	$95	$158	$90	$68	$141	$62	$79	$141	$62	$79	$141	$62	$79	$141	$62	$79
Commercial Windows Program	$1,000	$167	$833	$1,093	$171	$922	$438	$123	$315	$422	$119	$303	$380	$107	$273	$196	$55	$141
Commercial Insulation Program	$2,212	$235	$1,977	$1,752	$265	$1,486	$1,613	$103	$1,510	$1,435	$92	$1,343	$1,291	$83	$1,208	$951	$61	$890
Commercial New Construction Program	$193	$119	$75	$198	$124	$75	$569	$135	$434	$440	$104	$336	$529	$125	$403	$648	$153	$494
Commercial Building Optimization Program	$203	$147	$56	$118	$79	$39	$255	$111	$145	$193	$84	$109	$214	$93	$121	$214	$93	$121
Commercial Kitchen Appliance Program	$28	$9	$20	$46	$25	$21	$38	$8	$30	$88	$19	$69	$102	$22	$80	$105	$23	$83
CO2 Sensors	$32	$22	$10	$35	$23	$12	$58	$34	$24	$56	$33	$23	$58	$34	$24	$59	$35	$24
Commercial Water Heater Program	$30	$30	-	$14	$14	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Smart Energy Manager	$41	$39	$2	$3	$3	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Smart Shops	$87	$83	$4	$11	$11	-	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Boiler Program	$1,227	$256	$970	$881	$258	$623	$1,025	$296	$728	$543	$157	$386	$516	$149	$367	$7	$2	$5
Commercial Rinse & Save Program	$21	$2	$19	$1	$1	-	-	-	-	-	-	-	-	-	-	-	-	-
	$5,227	$1,167	$4,060	$4,310	$1,064	$3,246	$4,138	$873	$3,265	$3,317	$670	$2,648	$3,230	$675	$2,555	$2,320	$483	$1,837
INDUSTRIAL																		
Industrial Natural Gas Optimization Program	$700	$117	$583	$707	$172	$535	$770	$217	$554	$770	$217	$554	$640	$180	$460	$640	$180	$460
CUSTOMER SELF-GENERATION																		
Bioenergy Optimization Program	-	-	-	-	-	-	$139	$133	$6	$221	$37	$184	$43	$37	$6	$279	$37	$242
Option 1 & Customer Service Initiatives	$195	$791	-$596	$481	$1,161	-$680	$70	$44	$27	$282	$176	$106	$342	$213	$129	$617	$385	$233
Support Activity & Continency	$1,222	$591	$632	$1,393	$699	$694	$1,615	$780	$834	$1,578	$763	$816	$1,578	$763	$816	$1,578	$763	$816
Total Power Smart Utility Cost - Natural Gas	**$11,161**	**$3,304**	**$7,857**	**$10,906**	**$3,832**	**$7,074**	**$9,994**	**$2,511**	**$7,483**	**$9,405**	**$2,322**	**$7,084**	**$9,053**	**$2,325**	**$6,728**	**$7,801**	**$2,188**	**$5,614**

PUB/CENTRA II-168

Reference: PUB/Centra I-53(a), PUB/Centra I-57(a) & (b)

Please update PUB/Centra I-57(a) based on the 2013-2016 Power Smart Plan.

ANSWER:

Please see Centra's response to PUB/Centra II-166.

PUB/CENTRA II-169

Reference: PUB/Centra 1-54(b)

Please confirm whether the only difference between the schedule presented and the Utility Cost shown in Appendix C.3 of the 2011 Power Smart Plan relates to the Furnace Replacement Program and the Affordable Energy Fund costs.

ANSWER:

Confirmed.

PUB/CENTRA II-170

Reference: PUB/Centra I-56(a)

In a similar format as provided in PUB/Centra I-56(a), please provide the demographic data for gas customers only.

ANSWER:

	LICO Households in Manitoba					
	Natural Gas					
Dwelling Type	Own	% of Total LICO	Rent	% of Total LICO	Total By Dwelling Type	% of Total LICO
Single Detached	27,404	78%	2,068	6%	29,472	84%
Multi-Attached	3,065	9%	1,649	5%	4,714	14%
Apartment Suite	480	1%	212	1%	692	2%
Total by Ownership	30,949	88%	3,929	12%	34,878	100%

	LICO-125 Households in Manitoba					
	Natural Gas					
Dwelling Type	Own	% of Total LICO-125	Rent	% of Total LICO-125	Total By Dwelling Type	% of Total LICO-125
Single Detached	40,581	80%	2,464	5%	43,045	85%
Multi-Attached	4,944	9%	1,801	3%	6,745	12%
Apartment Suite	788	2%	307	1%	1,095	3%
Total by Ownership	46,313	91%	4,572	9%	50,885	100%

PUB/CENTRA II-171

Reference: PUB/Centra I-57

Please confirm whether the heading of the last column "PV of Energy Saved @ Gen (kWh)" is correct or whether the data in this column are natural gas savings in cubic metres. If the data are not related to natural gas savings, please re-file the table with natural gas savings.

ANSWER:

The data in the last column are natural gas savings in cubic metres. The heading was incorrectly labeled and should be "PV of Energy Saved (cu.m)".

PUB/CENTRA II-172

Reference: PUB/Centra I-59

a) Please explain why Centra is forecasting a decline in FRP furnace installations in 2014/15 from the prior year.

ANSWER:

Centra is no longer forecasting a decline in FRP furnace installations during the 2014/15 year from the prior year. Targets were revised under the 2013-2016 Power Smart Plan based upon participation to date. Please see Centra's response to PUB/Centra II-172(c) for updated FRP furnace installation targets.

PUB/CENTRA II-172

Reference: PUB/Centra I-59

b) Centra intends to cease funding from rates to the Furnace Replacement Program as of 2015/16. Please explain Centra's intentions for the remaining $19.6 million (forecasted) in the FRP fund.

ANSWER:

Centra intends to continue replacing standard efficient natural gas furnaces and boilers until such time as the number of participants diminishes to a level insufficient to justify the continuation of the program.

Centra has not yet determined its intention for the remaining balance of the Furnace Replacement fund following discontinuance of the program.

PUB/CENTRA II-172

Reference: PUB/Centra I-59

c) Please update the response to PUB/Centra I-59(a) based on the 2013-2016 Power Smart Plan extending the schedule to include 2015/16.

ANSWER:

Furnace Replacement Fund ending March 31 (000's)	2008/9 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Projected*	2013/14 Forecast**	2014/15 Forecast**	2015/16 Forecast**
Opening Balance	$ 2,327	$ 5,972	$ 9,050	$ 11,644	$ 14,145	$ 15,853	$ 17,644	$ 19,621
Funding from SGS Class	$ 3,855	$ 3,800	$ 3,762	$ 3,838	$ 3,800	$ 3,800	$ 3,800	$ -
Disbursements	$ (264)	$ (815)	$ (1,312)	$ (1,627)	$ (2,378)	$ (2,378)	$ (2,378)	$ (2,378)
Interest	$ 54	$ 93	$ 144	$ 290	$ 286	$ 369	$ 555	$ 746
Ending Balance	$ 5,972	$ 9,050	$ 11,644	$ 14,145	$ 15,853	$ 17,644	$ 19,621	$ 17,989
Number of Furnace Installations	280	508	445	662	660	900	937	1,018
Number of Boiler Installations	5	9	16	18	9	15	9	9
Cumulative Furnace Installations	280	788	1,233	1,895	2,555	3,455	4,393	5,410
Cumulative Boiler Installations	5	14	30	48	57	72	81	90

* 2012/13 values are a combination of actual values to the end of February, 2013 and forecasted values for March, 2013

** Disbursements indicated for the Forecast years do not include amounts in connection with the Neighbourhood Approach

PUB/CENTRA II-172

Reference: PUB/Centra I-59

d) Please estimate the number of furnaces and boilers (at the historical mix) that could be replaced under the FRP beginning in 2015/16 with the forecasted $19.6 million, and estimate how long until the FRP fund is depleted. Please also estimate the number of targeted furnaces that would remain after the FRP funds are depleted, factoring in furnaces that may be replaced independently of the FRP.

ANSWER:

Centra projects the Furnace and Boiler market would be depleted before all of the Furnace Replacement Funds are spent. The number of furnaces and boilers that could be replaced under the FRP beginning in 2015/16 are shown in the following table:

FRP Replacements	**2015/16 Forecast**	**2016/17 Forecast**	**2017/18 Forecast**	**2018/19 Forecast**
Number of Furnace Installations	1,018	1,183	1,183	312
Number of Boiler Installations	9	9	9	9
Cumulative Furnace Installations	5,410	6,593	7,776	8,088
Cumulative Boiler Installations	90	99	108	117

Furnace and boiler replacements could continue at the historical mix for the years 2015/16 through to 2017/18 but would drop off in year 2018/19 due to the reduced market size. The standard efficiency furnace market is projected to be depleted at the end of fiscal year

2018/19. The FRP Fund Balance is estimated to be $14,824,734 at the end of year 2018/19 based on the above activity.

The assumptions used in the Furnace Upgrade Market Table (see Appendix 7.3 p. 1) were also used to estimate the targeted standard furnaces remaining at the end of each year starting in 2015/16. Please see the chart below for the market estimations:

LIEEP Standard Efficiency Furnace Target Market			
Furnace Marketplace at Dec 1 2009	**LICO 125%**	**Non-LICO**	**All Dwellings**
Standard Furnace Market			
Owners	16,034	39,858	55,892
Rentals	2,285	2,152	4,437
Total Standard Furnaces (source: 2009 Survey)	18,319	42,010	60,329
Standard Furnaces Remaining at Fiscal Year End			
end of 2012/13	11,576	22,110	33,686
Furnace Marketplace Projections of Standard Furnaces Remaining			
end of 2015/16	5,307	8,194	13,500
end of 2016/17	3,223	4,521	7,744
end of 2017/18	1,223	1,191	2,413
end of 2018/19	0	0	0

PUB/CENTRA II-172

Reference: PUB/Centra I-59

e) Please confirm whether the Lower Income Energy Efficiency Program budget shown in PUB/Centra I-59(h) includes funding from the Furnace Replacement Program and the Affordable Energy Fund.

ANSWER:

Confirmed.

PUB/CENTRA II-172

Reference: PUB/Centra I-59

f) Please add a row to the table in PUB/Centra I-59(c) showing Centra's program administration and marketing unit cost per furnace and per boiler. Please confirm whether the program administration and marketing costs are included in the disbursements of the FRP.

ANSWER:

	Standard Furnace Replacement Average Cost	Standard Boiler Replacement Average Cost
Customer contribution	$ 1,140	$ 6,445
Centra contribution	$ 2,387	$ 2,500
Total equipment cost	$ 3,527	$ 8,945
Marketing/Administration cost	$ 871	$ 871

Centra does not differentiate between furnace and boiler marketing and administration costs. Instead, the costs are incurred across all Furnace Replacement installations. The average marketing and administration cost per heating system replaced under the program is $871. The program administration and marketing costs under the Furnace Replacement Program are included in the disbursements of the FRP.

PUB/CENTRA II-172

Reference: PUB/Centra I-59(g)

g) Please provide a breakdown of FRP disbursements for each of years 2008/09 through 2014/15.

ANSWER:

FRP Disbursements Breakdown	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual
Internal - Labour			$358,204	$405,447
Internal - Other		$1,231	$1,993	$3,259
Marketing			$88,167	$113,821
Payments to Contractors	$264,258	$813,975	$863,256	$1,104,506
Total	**$264,258**	**$815,205**	**$1,311,620**	**$1,627,033**

FRP Disbursements Breakdown	2012/13 Projected	2013/14 Forecast	2014/15 Forecast	Total
Internal - Labour	$452,017	$452,017	$452,017	**$2,119,704**
Internal - Other	$3,837	$3,837	$3,837	**$17,993**
Marketing	$119,560	$119,560	$119,560	**$560,668**
Payments to Contractors	$1,802,973	$1,802,973	$1,802,973	**$8,454,913**
Total	**$2,378,387**	**$2,378,387**	**$2,378,387**	**$11,153,277**

PUB/CENTRA II-173

Reference: PUB/Centra I-66

a) Please update the 2012/13 EDDH by including the March 2013 EDDH in the table shown in PUB/Centra I-66.

ANSWER:

Monthly DDH for Winnipeg													
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Annual
2008/09	319.8	180.9	21.3	0	3	56.3	227.9	546.4	1,033.0	1,052.3	800.9	676.4	4,918.2
2009/10	321.4	177.1	47.4	3.8	2.4	19.8	330.1	396.9	895.9	860.1	793.6	451.1	4,299.6
2010/11	173.5	108.8	10.3	0	9	79.9	188.7	520.6	878.1	1,031.2	788.9	698.8	4,487.8
2011/12	286.8	110.3	12.9	0	0	60.8	204	481.2	683.6	767.8	698.9	371.3	3,677.6
2012/13	244.3	82.7	9.9	0	0	89.1	310.9	601.1	889.6	951.1	781.7	770.8	4,731.2

PUB/CENTRA II-173

Reference: PUB/Centra I-66

b) Please reconcile the 25 year average EDDH shown in PUB/Centra I-66(c) with the 25 year average EDDH calculated from the information provided in 2011/12 COG CAC/Centra 16(a) and updated for the last three years in PUB/Centra 66(b). (Using the 2011/12 COG data, the EDDH differs from the PUB/Centra I-66(c) by approximately 55 EDDH each year in 2008/09 through 2011/12)

ANSWER:

The attachment in 2011/12 COG CAC/Centra I-16(a) was calculated using an extended set of historical actual weather data for the purpose of the weather normal study that was downloaded from the Environment Canada website. Upon further review, some historical daily values were missing from the 1937/38, 1993/94 and 1994/95 fiscal years that resulted in the variation of the calculated weather normal values provided in Centra's response to 2011/12 COG CAC/Centra 16(a). Attached is the updated table which provides consistent values to those provided in PUB/Centra I-66(c).

Fiscal Year	Actual DDH	Normal DDH			DDH Difference: Actual - Normal			DDH % Difference: Actual - Normal		
		10 Yr Avg	25 Yr Avg	Olympic	10 Yr Avg	25 Yr Avg	Olympic	10 Yr Avg	25 Yr Avg	Olympic
1874	4,550									
1875	5,713									
1876	5,816									
1877	5,445									
1878	3,768									
1879	4,965									
1880	5,421									
1881	5,497									
1882	5,261									
1883	5,642									
1884	5,985									
1885	5,760									
1886	5,242									
1887	5,583									
1888	5,746									
1889	4,737									
1890	5,364									
1891	4,939									
1892	5,006									
1893	5,634									
1894	5,474									
1895	4,895									
1896	4,892									
1897	5,229									
1898	4,777									
1899	5,383									
1900	4,664	5,159	5,287	5,159	-495	-623	-495	-10.6%	-13.4%	-10.6%
1901	4,693	5,089	5,245	5,070	-396	-552	-377	-8.4%	-11.8%	-8.0%
1902	4,208	5,065	5,200	5,065	-857	-992	-857	-20.4%	-23.6%	-20.4%
1903	4,693	4,985	5,151	4,995	-292	-457	-302	-6.2%	-9.7%	-6.4%
1904	5,176	4,891	5,188	4,971	286	-11	205	5.5%	-0.2%	4.0%
1905	4,653	4,861	5,196	4,988	-208	-543	-335	-4.5%	-11.7%	-7.2%
1906	4,569	4,837	5,165	4,906	-268	-597	-337	-5.9%	-13.1%	-7.4%
1907	4,802	4,805	5,128	4,824	-2	-326	-22	0.0%	-6.8%	-0.5%
1908	4,931	4,762	5,110	4,815	169	-179	116	3.4%	-3.6%	2.4%
1909	4,631	4,777	5,081	4,819	-147	-451	-188	-3.2%	-9.7%	-4.1%
1910	4,576	4,702	5,027	4,759	-126	-451	-183	-2.8%	-9.9%	-4.0%
1911	4,724	4,693	4,980	4,739	31	-256	-15	0.7%	-5.4%	-0.3%
1912	4,870	4,696	4,959	4,694	174	-89	176	3.6%	-1.8%	3.6%
1913	4,794	4,763	4,931	4,714	31	-137	80	0.7%	-2.9%	1.7%
1914	4,398	4,773	4,893	4,724	-374	-494	-326	-8.5%	-11.2%	-7.4%
1915	4,344	4,695	4,879	4,724	-351	-535	-380	-8.1%	-12.3%	-8.7%
1916	4,699	4,664	4,838	4,695	35	-139	4	0.7%	-3.0%	0.1%
1917	5,151	4,677	4,829	4,672	474	322	479	9.2%	6.3%	9.3%
1918	4,891	4,712	4,834	4,699	179	57	192	3.7%	1.2%	3.9%
1919	4,348	4,708	4,805	4,732	-360	-457	-384	-8.3%	-10.5%	-8.8%
1920	5,064	4,680	4,760	4,686	384	304	378	7.6%	6.0%	7.5%
1921	4,333	4,728	4,766	4,700	-396	-434	-368	-9.1%	-10.0%	-8.5%
1922	4,483	4,689	4,744	4,671	-206	-261	-188	-4.6%	-5.8%	-4.2%
1923	4,645	4,650	4,714	4,662	-5	-69	-17	-0.1%	-1.5%	-0.4%
1924	4,198	4,636	4,709	4,654	-438	-511	-456	-10.4%	-12.2%	-10.9%

Fiscal	Actual	Normal DDH			DDH Difference: Actual - Normal			DDH % Difference: Actual - Normal		
Year	DDH	10 Yr Avg	25 Yr Avg	Olympic	10 Yr Avg	25 Yr Avg	Olympic	10 Yr Avg	25 Yr Avg	Olympic
1925	4,903	4,616	4,662	4,600	287	241	303	5.9%	4.9%	6.2%
1926	4,483	4,671	4,671	4,611	-189	-188	-128	-4.2%	-4.2%	-2.9%
1927	4,679	4,650	4,663	4,619	29	16	60	0.6%	0.3%	1.3%
1928	4,635	4,603	4,682	4,653	33	-46	-18	0.7%	-1.0%	-0.4%
1929	4,613	4,577	4,679	4,646	36	-67	-33	0.8%	-1.4%	-0.7%
1930	4,835	4,603	4,657	4,601	232	179	234	4.8%	3.7%	4.8%
1931	4,124	4,581	4,664	4,596	-457	-540	-472	-11.1%	-13.1%	-11.4%
1932	4,297	4,560	4,646	4,581	-263	-350	-284	-6.1%	-8.1%	-6.6%
1933	4,980	4,541	4,626	4,520	439	354	460	8.8%	7.1%	9.2%
1934	4,995	4,575	4,628	4,577	421	367	418	8.4%	7.4%	8.4%
1935	4,617	4,654	4,642	4,627	-38	-26	-11	-0.8%	-0.6%	-0.2%
1936	5,562	4,626	4,644	4,624	936	918	938	16.8%	16.5%	16.9%
1937	5,175	4,734	4,678	4,704	441	497	471	8.5%	9.6%	9.1%
1938	4,601	4,783	4,690	4,731	-182	-88	-130	-4.0%	-1.9%	-2.8%
1939	4,780	4,780	4,682	4,743	1	98	37	0.0%	2.1%	0.8%
1940	4,357	4,797	4,697	4,753	-439	-340	-396	-10.1%	-7.8%	-9.1%
1941	4,491	4,749	4,698	4,725	-258	-207	-234	-5.7%	-4.6%	-5.2%
1942	4,143	4,785	4,690	4,713	-642	-546	-570	-15.5%	-13.2%	-13.7%
1943	5,126	4,770	4,649	4,644	356	477	482	6.9%	9.3%	9.4%
1944	4,481	4,785	4,659	4,742	-303	-177	-261	-6.8%	-4.0%	-5.8%
1945	4,148	4,733	4,664	4,760	-585	-516	-612	-14.1%	-12.4%	-14.7%
1946	4,962	4,686	4,627	4,677	275	334	285	5.5%	6.7%	5.7%
1947	4,810	4,626	4,652	4,674	184	158	136	3.8%	3.3%	2.8%
1948	5,056	4,590	4,666	4,693	466	390	363	9.2%	7.7%	7.2%
1949	4,798	4,635	4,682	4,681	162	116	116	3.4%	2.4%	2.4%
1950	5,031	4,637	4,706	4,648	394	325	383	7.8%	6.5%	7.6%
1951	5,165	4,705	4,711	4,691	461	454	474	8.9%	8.8%	9.2%
1952	4,802	4,772	4,738	4,726	30	63	76	0.6%	1.3%	1.6%
1953	4,193	4,838	4,743	4,770	-645	-550	-577	-15.4%	-13.1%	-13.8%
1954	4,367	4,745	4,726	4,741	-378	-359	-374	-8.7%	-8.2%	-8.6%
1955	4,805	4,733	4,716	4,762	72	89	43	1.5%	1.9%	0.9%
1956	4,868	4,799	4,715	4,730	69	153	138	1.4%	3.2%	2.8%
1957	4,794	4,789	4,744	4,769	4	50	25	0.1%	1.0%	0.5%
1958	4,120	4,788	4,764	4,829	-668	-645	-709	-16.2%	-15.6%	-17.2%
1959	4,789	4,694	4,730	4,752	95	60	37	2.0%	1.2%	0.8%
1960	4,788	4,693	4,722	4,750	94	66	38	2.0%	1.4%	0.8%
1961	4,410	4,669	4,728	4,723	-259	-318	-313	-5.9%	-7.2%	-7.1%
1962	5,005	4,594	4,682	4,685	411	322	320	8.2%	6.4%	6.4%
1963	4,597	4,614	4,676	4,682	-17	-78	-85	-0.4%	-1.7%	-1.8%
1964	4,422	4,654	4,675	4,641	-232	-253	-219	-5.3%	-5.7%	-5.0%
1965	5,206	4,660	4,661	4,603	546	545	603	10.5%	10.5%	11.6%
1966	5,049	4,700	4,695	4,684	349	353	365	6.9%	7.0%	7.2%
1967	5,227	4,718	4,717	4,753	509	509	474	9.7%	9.7%	9.1%
1968	4,785	4,761	4,761	4,793	24	24	-8	0.5%	0.5%	-0.2%
1969	4,878	4,828	4,747	4,784	50	131	94	1.0%	2.7%	1.9%
1970	4,915	4,836	4,763	4,793	78	152	122	1.6%	3.1%	2.5%
1971	4,968	4,849	4,794	4,843	118	174	125	2.4%	3.5%	2.5%
1972	5,041	4,905	4,794	4,861	136	247	180	2.7%	4.9%	3.6%
1973	4,646	4,909	4,803	4,886	-262	-157	-240	-5.6%	-3.4%	-5.2%
1974	5,145	4,914	4,787	4,909	231	358	236	4.5%	7.0%	4.6%
1975	4,741	4,986	4,801	4,923	-245	-60	-182	-5.2%	-1.3%	-3.8%
1976	4,631	4,939	4,789	4,937	-309	-158	-306	-6.7%	-3.4%	-6.6%

Fiscal	Actual	Normal DDH			DDH Difference: Actual - Normal			DDH % Difference: Actual - Normal		
Year	DDH	10 Yr Avg	25 Yr Avg	Olympic	10 Yr Avg	25 Yr Avg	Olympic	10 Yr Avg	25 Yr Avg	Olympic
1977	4,710	4,897	4,768	4,937	-188	-58	-227	-4.0%	-1.2%	-4.8%
1978	4,737	4,846	4,764	4,888	-109	-27	-151	-2.3%	-0.6%	-3.2%
1979	5,248	4,841	4,786	4,856	407	462	392	7.8%	8.8%	7.5%
1980	4,978	4,878	4,821	4,856	100	157	122	2.0%	3.2%	2.5%
1981	4,143	4,884	4,828	4,876	-741	-684	-733	-17.9%	-16.5%	-17.7%
1982	4,657	4,802	4,799	4,851	-145	-142	-194	-3.1%	-3.0%	-4.2%
1983	4,238	4,764	4,793	4,825	-525	-555	-587	-12.4%	-13.1%	-13.8%
1984	4,625	4,723	4,798	4,752	-98	-173	-127	-2.1%	-3.7%	-2.8%
1985	4,661	4,671	4,791	4,711	-10	-131	-51	-0.2%	-2.8%	-1.1%
1986	4,748	4,663	4,786	4,712	86	-38	36	1.8%	-0.8%	0.8%
1987	4,134	4,675	4,800	4,673	-540	-666	-539	-13.1%	-16.1%	-13.0%
1988	4,160	4,617	4,765	4,613	-457	-605	-453	-11.0%	-14.5%	-10.9%
1989	4,706	4,559	4,748	4,566	147	-42	140	3.1%	-0.9%	3.0%
1990	4,619	4,505	4,759	4,565	114	-140	54	2.5%	-3.0%	1.2%
1991	4,630	4,469	4,736	4,554	160	-106	75	3.5%	-2.3%	1.6%
1992	4,274	4,518	4,719	4,519	-244	-445	-245	-5.7%	-10.4%	-5.7%
1993	4,787	4,480	4,681	4,471	308	106	316	6.4%	2.2%	6.6%
1994	4,867	4,534	4,681	4,532	332	186	335	6.8%	3.8%	6.9%
1995	4,255	4,559	4,680	4,545	-304	-425	-290	-7.1%	-10.0%	-6.8%
1996	5,439	4,518	4,654	4,546	921	785	893	16.9%	14.4%	16.4%
1997	5,350	4,587	4,673	4,571	763	678	779	14.3%	12.7%	14.6%
1998	4,193	4,709	4,685	4,640	-516	-493	-447	-12.3%	-11.7%	-10.7%
1999	4,035	4,712	4,667	4,584	-677	-632	-549	-16.8%	-15.7%	-13.6%
2000	3,924	4,645	4,623	4,584	-721	-699	-661	-18.4%	-17.8%	-16.8%
2001	4,820	4,575	4,590	4,571	244	230	249	5.1%	4.8%	5.2%
2002	4,239	4,594	4,597	4,583	-355	-358	-344	-8.4%	-8.4%	-8.1%
2003	4,936	4,591	4,579	4,545	346	358	391	7.0%	7.2%	7.9%
2004	4,522	4,606	4,587	4,576	-84	-65	-54	-1.8%	-1.4%	-1.2%
2005	4,715	4,571	4,558	4,600	144	157	115	3.0%	3.3%	2.4%
2006	3,980	4,617	4,547	4,593	-637	-567	-613	-16.0%	-14.3%	-15.4%
2007	4,395	4,471	4,541	4,504	-77	-146	-109	-1.7%	-3.3%	-2.5%
2008	4,733	4,376	4,530	4,518	357	203	215	7.5%	4.3%	4.5%
2009	4,918	4,430	4,550	4,457	488	368	461	9.9%	7.5%	9.4%

PUB/CENTRA II-173

Reference: PUB/Centra I-66

c) Please confirm whether the reconciliation in (b) affects the forecast of EDDH for 2013/14 and the corresponding Test Year load forecast and/or revenue deficiency.

ANSWER:

The reconciliation does not affect the forecast of EDDH for 2013/14 and the corresponding Test Year load forecast and revenue deficiency.

PUB/CENTRA II-173

Reference: PUB/Centra I-66

d) Please reconcile the Net Income impact of $12.6 million for the warmest year on record shown in PUB/Centra I-66(f) with the weather impact shown in PUB/Centra I-13(a) for 2011/12 of $8.232 million, since both reflect EDDH of 3678.

ANSWER:

The $8.232 million shown in PUB/Centra I-13(a) represents the weather variance from January 1, 2012 to March 31, 2012 only. The following table shows the total weather impact for fiscal 2011/12 which is very similar to the $12.6 million shown in PUB/Centra I-66(f). The table below shows the EDDH and related net income impact for the period.

	April - December	January - March	Total	Actual Net Income Impact
Actual EDDH	1 840	1 838	3 678	(4 685 000)
Normal EDDH	2 181	2 356	4 537	(8 232 000)
	(341)	(518)	(859)	(12 917 000)

PUB/CENTRA II-174

Reference: PUB/Centra I-75

a) Please explain why the subsurface conditions at the CentrePort construction site were not more fully explored and evaluated prior to commencing construction.

ANSWER:

Manitoba Infrastructure and Transportation (MIT) performed an extensive geotechnical investigation at the CentrePort site as part of the larger roadway project. The geotechnical investigation included 31 test holes with depths ranging from 3.0 to 19.9 meters with locations selected to suit the roadway project. This information was provided to Manitoba Hydro for use in the pipeline installation. The available information included test holes in the vicinity of the two locations where difficulties with the installation of drills were experienced. All geotechnical information available from MIT was provided to the contractor in the tender process. This available information at the design and tendering time was considered to provide a reasonable evaluation of site conditions. Neither the project designers nor installation contractors identified any conditions that would be expected to present the difficulties that were experienced.

PUB/CENTRA II-174

Reference: PUB/Centra I-75

b) Please identify the causes or the parties responsible for the design changes that resulted in construction cost over-runs. If the design changes were made by a third party, please explain why the resulting cost over-runs were not recovered from this third party.

ANSWER:

Manitoba Infrastructure and Transportation (MIT) required design changes due to the design-build process and schedule impacts of the overall project. The design-build process requires final design to be taking place while construction has already commenced. Due to this design build process, Centra had to complete the gas main relocation while large scale earth works had already commenced on site. The earth works required two major routing changes to the gas main routing and an alteration of the north tie-in point. Centra has a 50/50 cost sharing agreement with MIT and the costs were jointly shared between parties.

PUB/CENTRA II-175

Reference: PUB/Centra 1-77

Please file the true-up related to the service expansion provided to the high volume customer in Minnedosa.

ANSWER:

As per the customer agreement, the project true-up using data to December 31, 2012 is anticipated to be complete on a best efforts basis by June 30, 2013. The results of the true-up will be filed with the Public Utilities Board when it is completed.

PUB/CENTRA II-176

Reference: PUB/Centra I-86(a) – Short Term Debt

Please explain what factors have led to Centra's weighting of short term debt falling from 20% of capital structure in 2008/09 to under 3% in 2012/13.

ANSWER:

This question references PUB/Centra I-86(a) which provides information derived for the theoretical rate base calculations and contains the disclaimer that "this information does not represent Centra's actual capital structure but rather the calculation of the capital structure that has been specified by the PUB."

The calculated reduction in the relative weighting of short term debt shown in the schedule is primarily the result of the cumulative amounts of capital financing that were converted from short term debt to long term debt with debt series CG9 ($30 million on September 1, 2009) and CG14 ($30 million on March 31, 2010).

PUB/CENTRA II-177

Reference: Tab 10 Page 5 of 63

a) Please provide the annual operating costs incurred by Centra to facilitate the Western Transportation Service. If any of these costs incurred are also necessary to facilitate FRPGS, please separately identify.

ANSWER:

The actual annual costs of facilitating the WTS for the past five fiscal years are denoted in the table below. While the migration of customers between Centra's quarterly variable Primary Gas rate and the FRPGS are facilitated through the direct purchase process, there are no incremental costs associated with doing so.

2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Outlook
$821,100	$759,100	$695,000	$671,400	$549,100

PUB/CENTRA II-177

Reference: Tab 10 Page 5 of 63

b) Please provide the bad debt expense by customer class specific to WTS customers for each of the past five years.

ANSWER:

Bad debt expense is a product of determining an appropriate level of the allowance for doubtful accounts in anticipation of future losses. Bad debt write-off is the specific customer receivable deemed to be uncollectible. The following is the bad debt write-off for the past five years for both (a) the primary gas portion of WTS customers and (b) all gas customers. A breakdown by customer class specific to WTS customers is not available.

	2007-08	2008-09	2009-10	2010-11	2011-12
Write-Off - WTS Primary Gas Only	$ 220 549	$ 220 701	$ 299 551	$ 181 798	$ 116 017
Write-Off - All Gas Customers	$ 2 577 816	$ 2 162 739	$ 2 026 025	$ 1 866 223	$ 1 356 825

PUB/CENTRA II-177

Reference: Tab 10 Page 5 of 63

c) Please provide Centra's views on whether it is appropriate to recover these costs from the brokers and retailers who make use of WTS.

ANSWER:

In Order 160/07, the PUB directed that the costs incurred to facilitate choice provide benefit to all customers and therefore all customers should continue to pay for these costs through the Distribution Rate. Centra continues to recover all costs of WTS through the Distribution rate as directed in this Order and does not take issue with this direction.

PUB/CENTRA II-178

Reference: PUB/Centra I-94 – NEB Decision

In the high level update of the NEB's Decision on TCPL's Business and Services Restructuring Application that is being prepared as stated in PUB/Centra I‐94, please address the NEB's decision on each of the points Centra advocated in its closing submission, and how Centra anticipates these decisions will affect Centra and its ratepayers, both in the Test Year and beyond.

ANSWER:

The NEB issued its Reasons for Decision (the "decision") related to the RH-003-2011 hearing on TransCanada's Restructuring Proposal on March 27, 2013 to fix multi-year tolls on the Canadian Mainline (the "Mainline"). Highlights of the decision are as follow:

- The NEB approved multi-year fixed tolls which the NEB deemed to be competitive and provide TransCanada with a reasonable opportunity to recover its Mainline costs given the increase in Mainline throughput which is forecast. In its decision, the NEB established the Firm Transportation toll from Empress, Alberta to Dawn, Ontario at $1.42/GJ compared to the current interim toll of $1.89/GJ.
- The NEB expects this toll to remain in effect through 2017. Recognizing the increased business risk the Mainline is facing, the NEB approved the Mainline's return on equity at 11.5 per cent on a 40 per cent equity ratio. The NEB also approved an incentive mechanism which would further increase the Mainline's profits if annual net revenues are higher than forecast.

- The NEB developed a streamlined regulatory process for the Mainline to address new service and pricing proposals in a timelier manner.
- The NEB approved all of TransCanada's proposed changes to the Mainline's cost allocation and the elimination of both FT-RAM and toll zones on the Mainline. The NEB also gave greater discretion to TransCanada on how it prices IT and STFT services on the Mainline.
- The NEB did not approve other TransCanada proposals, including the Alberta System Extension (ASE). Among other things, the NEB viewed the ASE as inappropriate cost shifting among affiliated companies that is contrary to sound tolling principles. The NEB also denied the reallocation of accumulated depreciation and the new proposed treatment of costs related to TransCanada's agreement for transportation services on Trans Québec and Maritimes (TQM) Pipeline Inc.'s pipeline system.
- The NEB denied intervener proposals to disallow costs from the Mainline's rate base or revenue requirement.

The NEB observed in its decision that the Mainline is in an unprecedented position. No major NEB-regulated natural gas transmission pipeline has ever been affected by market forces to the extent that the Mainline is now affected. Throughput on the Mainline has decreased significantly, and as a result, Mainline tolls have increased substantially over a short period of time. The future of the Mainline depends on how TransCanada is able to respond to the changes to its business environment. The NEB also noted that it has provided TransCanada with the tools it requires to achieve positive outcomes for its investors and customers, and that TransCanada must now use those tools to construct a viable future.

Relative to the status quo the decision is directionally positive for Centra and its ratepayers although the net cost impact is uncertain at this point and the decision contains elements which are both favourable and unfavourable.

The NEB expects this toll to remain in effect through 2017 which has the potential to provide for toll certainty and stability and may facilitate contracting for Centra and the broader marketplace at least in the short-term; however there are off-ramps defined within the decision which could lead to the multi-year fixed tolls being in place for less time than expected.

The NEB gave greater discretion to TransCanada on how it prices Interruptible Transportation (IT) service and Short Term Firm Transportation (STFT) service on the Mainline. Centra has recently used STFT to shape its transportation contracts to better match its load curve. Centra anticipates that TransCanada will price STFT to Centra's delivery points (which TransCanada considers captive) at a price which will economically incent Centra back into holding more annual FT capacity. This will result in Centra having more Unutilized Demand Charges (UDC) to mitigate in the secondary market.

Centra's most effective UDC mitigation tool, the FT-Risk Alleviation Mechanism (FT-RAM), was eliminated by way of the decision. Centra will return to using FT-Diversions as a way of mitigating its UDC but, due to the nature of the market which it serves, FT-Diversions will be less effective than using FT-RAM. Centra was able to reduce its fixed costs on the Mainline by almost $5 million in the 2011/12 gas year through its use of the FT-RAM service attribute.

On May 1, 2013 TransCanada made a Compliance Filing which included an Application to Review and Vary portions of the NEB decision.

Centra along with other shippers awaits confirmation of tolls for all paths and services; and bid floors for IT and STFT services. Once this information becomes available, Centra will evaluate its options using this information to inform its transportation contracting and gas supply purchase decisions going forward.

Centra's three key expectations of TransCanada as one of its service providers and as outlined by Centra in its closing submission in the RH-003-2011 proceeding were as follow:

1) For stable and predictable tolls;
2) For TransCanada to be competitive; and
3) For TransCanada's interests and those of Mainline shippers to be more closely aligned such that the risk and costs of underutilization are shared.

Although there is some ambiguity in these objectives, in Centra's opinion the NEB's decision goes a long way to meeting all of these expectations.

Please find below a chart which presents the key components of TransCanada's proposal as compared with the position taken by Centra in its final argument and the NEB's decision.

TransCanada's Proposal	Centra	NEB Decision
Alberta System Extension	Against	Not Approved
Accumulated Depreciation Transfer	Against	Not Approved
Toll Design Changes		
• Elimination of toll zones	For	Approved
• Improvements to cost allocation	For	Approved
• Allocation of TBO costs on TQM system	No Position	Not Approved
Service & Pricing Changes		
• RAM Elimination	Against	Approved
• Multi-Year Fixed Price Service (MFP)	Against	Approved
• Pricing flexibility (IT/STFT)	*	Approved +
Return and other Cost of Service elements	No Position	Approved

*Centra's position on the appropriateness of granting TransCanada with pricing discretion was influenced by whether the discretion would be accompanied by regulatory oversight and TransCanada being accountable for the financial outcomes of the exercising of its discretion.

+ Approved with additional flexibility beyond what was requested by TCPL.

PUB/CENTRA II-179

Reference: PUB/Centra I-102(b); Tab 10 Page 36 of 63; Schedules 10.4.1, 10.8.1

a) Centra presumably pays its Primary Gas Delivered Service suppliers according to a formula (or formulas) that takes into account one or more published indices. Please provide the pricing formula(s) or mechanism(s) for Primary Gas Delivered Service.

ANSWER:

Centra pays Primary Gas Delivered Service ("PGDS") suppliers based on the "AECO Monthly 7A Index" plus a fixed fee which reflects the cost charged by the counterparty to transport gas from AECO to the delivery location.

PUB/CENTRA II-179

Reference: PUB/Centra I-102(b); Tab 10 Page 36 of 63; Schedules 10.4.1, 10.8.1

b) Please demonstrate how Centra calculates the upstream compressor fuel costs when it imputes the transportation component of the Primary Gas Delivered Service price.

ANSWER:

TransCanada's monthly mainline compressor fuel ratio is multiplied by the unit commodity price of natural gas at Empress, with the result then applied against the total Primary Gas Delivered Service volumes. The following is an example of the aforementioned calculation:

TransCanada Mainline Compressor Fuel Ratio = 0.79%

Commodity Price at Empress = $2.9362/GJ

Total Primary Gas Delivered Service Volumes = 300,000 GJ's

Upstream Compressor Fuel Unit Cost = 0.79% x $2.9362/GJ = $0.0232/GJ

Total Compressor Fuel Costs = $0.0232/GJ x 300,000 GJ's = $6,959

PUB/CENTRA II-179

Reference: PUB/Centra I-102(b); Tab 10 Page 36 of 63; Schedules 10.4.1, 10.8.1

c) Please give Centra's view of whether the Primary Gas Rate Setting Methodology requires amendment to reflect the pricing formula for Primary Gas Delivered Service.

ANSWER:

Centra does not believe that the Primary Gas Rate Setting Methodology requires amendment at this time. In the event that Centra utilizes Primary Gas Delivered Service, the associated costs would be captured in the Primary Gas PGVA, which would be disposed as part of the subsequent Quarterly Primary Gas Rate Application.

PUB/CENTRA II-179

Reference: PUB/Centra I-102(b); Tab 10 Page 36 of 63; Schedules 10.4.1, 10.8.1

d) Please explain why the Primary Gas Supply Prices at Empress provided in PUB/Centra I-102(a) multiplied by the Primary Gas Supply volumes in PUB/Centra I-102(b) rows 5 and 15 do not reconcile with the inflows into the Primary Gas PGVA shown in Schedules 10.4.1 and 10.8.1 row 2.

ANSWER:

Multiplying the monthly average cost of purchases from ConocoPhillips at Empress on lines 3 and 23 of PUB/Centra 1-102(a) by the volumes shown on rows 5 and 15 of PUB/Centra 1-102(b) will not yield the figures shown on row 2 of Schedules 10.4.1 and 10.8.1 for a number of reasons.

In addition to the cost of purchases from ConocoPhillips at Empress, the figures on row 2 of Schedules 10.4.1 and 10.8.1 also include monthly amounts relating to short-term park and loan arrangements on the TransCanada Mainline, as well as loans and repayments of storage gas to and from WTS marketers. These amounts are minor in aggregate and net to a total credit contribution (i.e. a cost reduction embedded in the Primary Gas costs depicted on row 2 of Schedules 10.4.1 and 10.8.1) of $1.5 million or approximately 1% of the total amount depicted on row 2 of the schedules in question over the two-year period.

As well, the Primary Gas volumes shown on rows 5 and 15 of PUB/Centra 1-102(b) include, in addition to purchases from ConocoPhillips at Empress, volumes related to short-term

TransCanada park and loan arrangements, WTS storage loans, and limited balancing agreement and T-Service customer imbalances on the TransCanada Mainline.

PUB/CENTRA II-179

Reference: PUB/Centra I-102(b); Tab 10 Page 36 of 63; Schedules 10.4.1, 10.8.1

e) Please explain the circumstances that have caused the Primary Gas Supply Price at Empress to exceed the AECO monthly price by $0.75/GJ in October 2012, compared to the average for the previous 11 months of $0.11/GJ.

ANSWER:

The NGX AB-NIT (7A) Month Ahead Index price for October 2012 was established at $2.34/GJ based on the volume-weighted average price of trades in the October 2012 futures contract during the month of September 2012. By comparison, NGX AB-NIT (2A) Same Day Index prices increased significantly relative to the monthly index throughout the month of October 2012, rising to nearly $3.20/GJ during the period. Because a significant portion of Centra's Primary Gas purchases during October 2012 were indexed to same day prices, Centra's average cost of October 2012 Primary Gas was noticeably higher than the October 2012 AECO monthly index price determined during September 2012.

PUB/CENTRA II-179

Reference: PUB/Centra I-102(b); Tab 10 Page 36 of 63; Schedules 10.4.1, 10.8.1

f) Please provide the monthly Primary Gas baseload volumes from Empress, the monthly Primary Gas swing volumes from Empress, the average AECO daily price for each month, the AECO to Empress Nova tolls, the AECO to Empress Transportation Basis Differentials, and the monthly Primary Gas sales volumes for the period November 2010 to October 2012. If Centra claims any portions of this information to be commercially sensitive information, such portions may be filed in confidence, with a redacted response being filed on the public record.

ANSWER:

Please see attachment to this response.

Centra Gas Manitoba Inc.
2013/14 General Rate Application
Primary Baseload & Swing Volumes, Daily and Monthly Pricing Components

PUB/Centra II-179 (f)
Attachment
May 7, 2013

Line	Description	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Total
1	Primary Gas Baseload Volumes from Empress (ConocoPhillips)[1]	1,619,700	2,047,550	2,425,750	1,867,600	1,556,820	1,396,800	1,194,430	1,408,500	2,224,870	2,171,860	1,411,200	855,600	**20,180,680**
2	Monthly Primary Gas Swing Volumes from Empress (ConocoPhillips)[1]	1,397,879	1,523,960	1,135,280	1,355,930	1,960,132	1,636,526	880,784	429,254	61,209	169,921	504,681	1,179,343	**12,234,899**
3	Centra Primary Gas Sales Volumes	3,984,318	6,221,736	6,937,572	5,593,938	4,971,003	2,477,526	1,591,395	831,886	707,571	721,409	972,462	1,957,990	**36,968,805**
4														
5	Average AECO Daily Spot Price (NGX)	$3.4786	$3.6995	$3.7845	$3.4132	$3.5259	$3.5414	$3.7006	$3.7944	$3.5108	$3.4502	$3.4420	$3.2019	
6	AECO to Empress Nova Tolls (NGTL)	$0.1982	$0.1982	$0.1982	$0.1982	$0.1982	$0.1982	$0.1982	$0.1982	$0.1982	$0.1982	$0.1982	$0.1930	
7	AECO to Empress Monthly Basis Differential Index (CGPR)	($0.1152)	($0.1509)	($0.1134)	($0.1209)	($0.1000)	($0.1603)	($0.1816)	($0.1729)	($0.1630)	($0.2029)	($0.2384)	($0.2776)	
8														
9														
10		**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Total**
11														
12	Primary Gas Baseload Volumes from Empress (ConocoPhillips)[1]	526,200	1,529,230	1,478,700	625,240	431,830	-	-	309,900	1,484,280	1,487,380	742,500	156,240	**8,771,500**
13	Monthly Primary Gas Swing Volumes from Empress (ConocoPhillips)[1]	1,716,330	1,151,756	727,568	1,429,612	1,063,463	1,517,395	575,994	711,744	92,132	165,829	531,994	2,134,626	**11,818,443**
14	Centra Primary Gas Sales Volumes	4,556,616	6,209,236	6,895,718	6,059,689	3,950,897	2,771,343	1,494,099	1,187,267	798,461	835,266	1,274,481	3,252,975	**39,286,048**
15														
16	Average AECO Daily Spot Price (NGX)	$3.0872	$2.8112	$2.4204	$2.0493	$1.6983	$1.5937	$1.9452	$1.8586	$2.2235	$2.0847	$2.1848	$2.9222	
17	AECO to Empress Nova Tolls (NGTL)	$0.1930	$0.1930	$0.1740	$0.1740	$0.1740	$0.1740	$0.1740	$0.1740	$0.1740	$0.1740	$0.1740	$0.1740	
18	AECO to Empress Monthly Basis Differential Index (CGPR)	($0.3393)	($0.3807)	($0.3811)	($0.3278)	($0.2017)	($0.3347)	($0.1531)	$0.0245	$0.1183	$0.0161	$0.1123	$0.1196	
19														
20	**Note 1: Primary Gas Storage purchases are included.**													
21														

PUB/CENTRA II-180

Reference: PUB/Centra I-104

a) Please explain why Centra is of the view that DSM investments, which are fixed and are independent of consumption, should be recovered volumetrically by classifying these costs as Energy.

ANSWER:

It should be noted that DSM costs are not classified as energy for the purpose of allocating among classes but rather for rate design purposes. DSM costs are first assigned directly to rate classes on the basis of anticipated program uptake, that is, according to cost causation among the rate classes. This methodology was approved by the PUB in Order 99/07. Once assigned to classes, the costs are recovered through the commodity charge applied to each class.

Centra believes it is appropriate to recover DSM costs, once assigned directly to rate classes, through the commodity portion of the rate. DSM services are intended to substitute for commodity usage and DSM benefits are associated with reduction in commodity uptake. Once they have participated in DSM programming, customers realize their bill savings through a reduction in commodity usage. Generally, larger users have more capability to conserve (e.g. larger homes, more appliances or more commercial or industrial processes) and consequently are likely to have greater uptake of DSM programs.

Finally, it should be noted that this issue is moot in the case of the SGS (Residential and Small Commercial) and LGS classes which are assigned the vast majority (92%) of the DSM costs. This is because the BMC for these classes recovers only a portion of fixed customer related cost. Even if DSM were considered to be a fixed cost, and classified as customer related, its costs would still be recovered through the commodity charge.

PUB/CENTRA II-180

Reference: PUB/Centra I-104

b) Please provide the impacts related to the change in the allocation of DSM costs for the HVF and INT customer classes for the lowest, average, and highest consumption levels and load factors.

ANSWER:

The following table shows the impact of the change in the DSM classification for purposes of rate design. The column "DSM-Onsite" reflects the impact of functionalizing DSM costs as On-Site and classifying these costs as Customer related. Centra has also reflected the bill impacts of the Mainline class in the table as it is this class that is most affected by the DSM change.

Base Rate Bill Impact	2013/14 TY						
	Load	Annual Use		Annual Bill		Bill Impact	
	Factor	10^3m^3	Mcf	As filed	DSM-Onsite	$	%
High Volume Firm	25%	850	30,000	$187,789	$189,041	-$1,252	-0.7%
	40%	850	30,001	$170,645	$171,897	-$1,252	-0.7%
	40%	1,416	50,000	$274,565	$275,024	-$459	-0.2%
	40%	2,833	100,000	$534,378	$532,853	$1,524	0.3%
	40%	6,200	218,866	$1,152,036	$1,145,797	$6,238	0.5%
	40%	12,600	444,792	$2,326,006	$2,310,808	$15,198	0.7%
	75%	685	24,181	$129,652	$131,135	-$1,483	-1.1%
	75%	850	30,000	$157,301	$158,553	-$1,252	-0.8%
	75%	1,416	50,000	$252,334	$252,793	-$459	-0.2%
	75%	2,833	100,000	$489,916	$488,392	$1,524	0.3%
	75%	6,200	218,866	$1,054,725	$1,048,486	$6,238	0.6%
	75%	12,600	444,792	$2,128,245	$2,113,047	$15,198	0.7%
Mainline Firm	40%	2,833	100,000	$525,384	$572,190	-$46,806	-8.9%
	40%	14,164	500,000	$2,566,603	$2,576,016	-$9,414	-0.4%
	40%	28,328	1,000,000	$5,118,126	$5,080,799	$37,327	0.7%
	75%	2,833	100,000	$464,385	$511,192	-$46,806	-10.1%
	75%	14,164	500,000	$2,261,609	$2,271,023	-$9,414	-0.4%
	75%	28,328	1,000,000	$4,508,139	$4,470,811	$37,327	0.8%
	75%	41,000	1,447,339	$6,518,061	$6,438,916	$79,145	1.2%
Interruptible Sales	25%	850	30,000	$159,037	$162,953	-$3,916	-2.5%
	40%	2,833	100,000	$466,915	$466,865	$50	0.0%
	40%	14,164	500,000	$2,273,921	$2,251,209	$22,712	1.0%
	75%	850	30,000	$144,196	$148,112	-$3,916	-2.7%
	75%	2,833	100,000	$445,271	$445,221	$50	0.0%
	75%	14,164	500,000	$2,165,701	$2,142,988	$22,712	1.0%

PUB/CENTRA II-181

Reference: PUB/Centra I-107

a) Please provide a table showing the changes in the BMC for the SGS and LGS customer classes since 2006/07.

ANSWER:

The table below shows the changes in the BMC for the SGS and LGS customer classes since 2006/07.

Date	SGS ($/month)	LGS ($/month)
previous	$10.00	$70.00
August 1, 2007	$12.00	$70.00
May 1, 2008	$13.00	$70.00
May 1, 2010	$14.00	$77.00

PUB/CENTRA II-181

Reference: PUB/Centra I-107

b) Please compare Centra's residential BMC with the current residential BMCs for the major Canadian gas utilities as well as for Swan Valley Gas Corporation.

ANSWER:

The residential BMC's for major Canadian gas utilities and Swan Valley Gas Corporation are provided in the table below:

Basic Monthly Charges as of April 1, 2013

Utility	Rate class/Service area	BMC ($/month)
FortisBC Inc. Gas[1)]	Residential - Lower Mainland	$11.67
ATCO Gas North[1)]	Low Use Delivery Service	$26.67
ATCO Gas South[1)]	Low Use Delivery Service	$23.04
SaskEnergy	Residential	$18.85
Swan Valley Gas	Residential	$20.00
Centra Gas Manitoba Inc.	Residential - SGS	$14.00
Union Gas	Southern Residential	$21.00
Enbridge Gas Distribution	Residential	$20.00
GazMetro[1)]	Residential	$13.95

[1)] Monthly charge calculated based on a 30 day month.

PUB/CENTRA II-181

Reference: PUB/Centra I-107

c) Please discuss whether Centra has a long term goal in respect of structuring the BMC for the SGS and LGS classes to recover a greater portion of its customer-related costs.

ANSWER:

Centra does not presently intend to increase the level of the BMC for the SGS and LGS customer classes to recover a greater portion of customer-related costs.

The BMC is a minimum bill concept that is intended to ensure that customers contribute a reasonable amount toward the fixed customer related costs of the utility including the costs of meter reading, billing and collections, meters, and regulators. Centra currently recovers approximately 50% of its customer-related costs through its fixed BMC for these customer classes.

In 2005, Centra filed a BMC report which concluded that the BMC not be changed for these customer classes as it was viewed as striking a reasonable balance between various rate design considerations. Some of these rate design considerations could include:

- Rates should be reflective of the costs incurred to provide service;
- Rates should be fair and equitable;
- Rates should provide for revenue stability and predictability;

- Rates should be publicly acceptable;
- Rates should be simple and understandable; and
- Rates should be competitive.

Since that time, Centra has not requested any increase to the BMC, but the PUB has directed several increases. Centra is of the view the current focus on demand side management and low income programs provide additional rate design considerations in support of greater emphasis on the volumetric charge. In addition, Centra is part of the larger Manitoba Hydro, which has been following a strategy of emphasizing in its rate proposals the part of the bill that is most conservable. Finally, a high monthly BMC may discourage uptake of natural gas service in some situations where it would otherwise be beneficial for both the customer and Manitoba Hydro.

PUB/CENTRA II-181

Reference: PUB/Centra I-107

d) Please discuss whether Centra has a long term goal in respect of recovering the full demand-related costs of the High Volume Firm and Interruptible classes in the demand charge.

ANSWER:

Centra's rate design for the HVF and Interruptible classes currently recovers 65% of their respective capacity costs by way of the demand charge. This level of demand recovery through the demand rate has been in place since 2004. There are several seasonal customers within these classes that do not pay demand rates. If Centra moves to recovering all the demand costs in the demand rate for this class, these customers will not contribute to any fixed capacity costs. Given that capacity-related costs are largely recovered through the monthly demand and in light of the seasonal customer circumstance, Centra is satisfied that the current rate design reflects a reasonable balance between the nature of the costs and their recovery with the practical realities of its system, and has no plans at this time to recommend a change in this methodology.

PUB/CENTRA II-182

Reference: PUB/Centra I-119; Tab 11 Schedule 11.1.0

a) Please confirm whether the Minimum Annual Gross Margin Amount was established based on the original feasibility tests for extension of service to these customers. If not confirmed, please explain the basis for the MAGMA.

ANSWER:

The Minimum Annual Gross Margin Amount (MAGMA) was established based on rates flowing from Centra's Cost Allocation Study filed with the PUB on January 31, 2003 as part of Centra's 2003/04 GRA along with the load forecast filed in that Application. This data was used in the feasibility test to calculate the MAGMA.

PUB/CENTRA II-182

Reference: PUB/Centra I-119; Tab 11 Schedule 11.1.0

b) Order 118/03 speaks of three true-up calculations embedded in the customer contracts. Please file these true-up calculations.

ANSWER:

Please see Attachment 1 to this response for the results of the two initial True-ups, which were to be completed on or about October 31, 2003, and were filed in response to Information Request PUB/Centra I-159 as part of the 2007/08 & 2008/09 General Rate Application.

Please see Attachment 2 to this response for the results of the second True-ups which were to be completed on or about October 31st, 2008.

The contracts stipulate that the final True-up period concludes on July 31, 2013. The True-ups are to be completed on or about October 31, 2013. The final two True-ups will be filed with the PUB upon completion.

Centra Gas Manitoba Inc.
2007/08 & 2008/09 General Rate Application
Financial Feasibility Test

1	**Brandon Combustion Turbine Project - Initial True Up**											
2		TIME 0 2001	YEAR 1 2002	YEAR 2 2003	YEAR 3 2004	YEAR 4 2005	YEAR 5 2006	YEAR 6 2007	YEAR 7 2008	YEAR 8 2009	YEAR 9 2010	YEAR 10 2011
3	OPERATING ASSUMPTIONS											
4	Number of Customers		1	1	1	1	1	1	1	1	1	1
5	Annual Volume (Mcf)		1,280,259	1,533,371	3,212,574	3,212,574	3,212,574	3,212,574	3,212,574	3,212,574	3,212,574	3,212,574
6	Annual Volume (10^3m^3)		36,267	43,437	91,005	91,005	91,005	91,005	91,005	91,005	91,005	91,005
7	Projected Revenues		$189,412	$695,552	$718,065	$718,065	$718,065	$718,065	$718,065	$718,065	$718,065	$718,065
8	RATE BASE											
9	Gross Fixed Assets	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471
10	Accumulated Depreciation		$77,191	$172,226	$257,008	$341,789	$426,571	$511,353	$596,135	$680,917	$765,699	$850,481
11	Contributions	$765,001	$750,026	$731,589	$715,142	$698,694	$682,247	$665,799	$649,352	$632,904	$616,457	$600,009
12	Working Capital Allowance		$4,765	$5,660	$10,377	$10,357	$10,337	$10,317	$10,297	$10,277	$10,257	$10,237
13	Rate Base		$3,164,127	$3,095,615	$3,027,866	$2,959,512	$2,891,158	$2,822,803	$2,754,449	$2,686,094	$2,617,740	$2,549,385
14	REVENUE DEFICIENCY											
15												
16	Cost of Gas		$67,659	$70,327	$145,465	$145,465	$145,465	$145,465	$145,465	$145,465	$145,465	$145,465
17	Operating & Maintenance Expenses		$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161
18	Depreciation Expense		$77,191	$95,035	$84,782	$84,782	$84,782	$84,782	$84,782	$84,782	$84,782	$84,782
19	Amortization of Contributions		($14,975)	($18,437)	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)
20	Municipal Tax & Corp.Cap. Tax		$66,852	$66,377	$65,953	$65,529	$65,105	$64,681	$64,257	$63,833	$63,409	$62,985
21	Income Taxes		$103,706	$59,482	$51,872	$53,806	$55,575	$57,188	$58,649	$59,966	$61,143	$62,187
22	Overall Return		$281,398	$265,949	$245,257	$239,720	$234,184	$228,647	$223,110	$217,574	$212,037	$206,500
23	Total Revenue Requirement		$589,992	$546,895	$585,043	$581,016	$576,825	$572,476	$567,977	$563,333	$558,550	$553,633
24	Projected Revenues		$189,412	$695,552	$718,065	$718,065	$718,065	$718,065	$718,065	$718,065	$718,065	$718,065
25	Revenue Sufficiency (Deficiency)		($400,580)	$148,657	$133,022	$137,049	$141,240	$145,589	$150,088	$154,732	$159,515	$164,432
26	Revenue to Cost Ratio		32.1%	127.2%	122.7%	123.6%	124.5%	125.4%	126.4%	127.5%	128.6%	129.7%
27	NPV of Revenue Deficiency	$1										
28	CONTRIBUTION REQUIREMENT											
29	Total Contribution Required	$765,001										

Centra Gas Manitoba Inc.
2007/08 & 2008/09 General Rate Application
Financial Feasibility Test

1 **Brandon Combustion Turbine Project - Initial True Up**

#		YEAR 11 2012	YEAR 12 2013	YEAR 13 2014	YEAR 14 2015	YEAR 15 2016	YEAR 16 2017	YEAR 17 2018	YEAR 18 2019	YEAR 19 2020	YEAR 20 2021
2											
3	OPERATING ASSUMPTIONS										
4	Number of Customers	1	1	1	1	1	1	1	1	1	1
5	Annual Volume (Mcf)	3,212,574	1,878,587	11,004	11,004	11,004	11,004	11,004	11,004	11,004	11,004
6	Annual Volume (10^3m^3)	91,005	53,216	312	312	312	312	312	312	312	312
7	Projected Revenues	$718,065	$524,326	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847
8	RATE BASE										
9	Gross Fixed Assets	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471
10	Accumulated Depreciation	$935,263	$1,020,045	$1,104,827	$1,189,609	$1,274,391	$1,359,173	$1,443,954	$1,528,736	$1,613,518	$1,698,300
11	Contributions	$583,562	$567,114	$550,667	$534,219	$517,772	$501,324	$484,877	$468,429	$451,982	$435,534
12	Working Capital Allowance	$10,217	$7,349	$3,341	$3,321	$3,301	$3,281	$3,261	$3,241	$3,221	$3,201
13	Rate Base	$2,481,031	$2,409,828	$2,337,486	$2,269,132	$2,200,777	$2,132,423	$2,064,068	$1,995,714	$1,927,359	$1,859,005
14	REVENUE DEFICIENCY										
15											
16	Cost of Gas	$145,465	$85,196	$819	$819	$819	$819	$819	$819	$819	$819
17	Operating & Maintenance Expenses	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161
18	Depreciation Expense	$84,782	$84,782	$84,782	$84,782	$84,782	$84,782	$84,782	$84,782	$84,782	$84,782
19	Amortization of Contributions	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)
20	Municipal Tax & Corp.Cap. Tax	$62,562	$62,138	$61,714	$61,290	$60,866	$60,442	$60,018	$59,594	$59,170	$58,746
21	Income Taxes	$63,102	$63,805	$64,353	$64,914	$65,366	$65,713	$65,960	$66,111	$66,169	$66,138
22	Overall Return	$200,964	$195,196	$189,336	$183,800	$178,263	$172,726	$167,190	$161,653	$156,116	$150,579
23	Total Revenue Requirement	$548,588	$482,830	$392,717	$387,317	$381,809	$376,195	$370,482	$364,672	$358,769	$352,778
24	Projected Revenues	$718,065	$524,326	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847
25	Revenue Sufficiency (Deficiency)	$169,477	$41,497	($235,870)	($230,470)	($224,962)	($219,348)	($213,635)	($207,825)	($201,922)	($195,931)
26	Revenue to Cost Ratio	130.9%	108.6%	39.9%	40.5%	41.1%	41.7%	42.3%	43.0%	43.7%	44.5%

Centra Gas Manitoba Inc.
2007/08 & 2008/09 General Rate Application
Financial Feasibility Test

1 **Brandon Combustion Turbine Project - Initial True Up**

#		YEAR 21 2022	YEAR 22 2023	YEAR 23 2024	YEAR 24 2025	YEAR 25 2026	YEAR 26 2027	YEAR 27 2028	YEAR 28 2029	YEAR 29 2030	YEAR 30 2031
2											
3	OPERATING ASSUMPTIONS										
4	Number of Customers	1	1	1	1	1	1	1	1	1	1
5	Annual Volume (Mcf)	11,004	11,004	11,004	11,004	11,004	11,004	11,004	11,004	11,004	11,004
6	Annual Volume (10^3m^3)	312	312	312	312	312	312	312	312	312	312
7	Projected Revenues	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847
8	RATE BASE										
9	Gross Fixed Assets	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471	$3,955,471
10	Accumulated Depreciation	$1,783,082	$1,867,864	$1,952,646	$2,037,428	$2,122,210	$2,206,992	$2,291,774	$2,376,556	$2,461,338	$2,546,119
11	Contributions	$419,087	$402,639	$386,191	$369,744	$353,296	$336,849	$320,401	$303,954	$287,506	$271,059
12	Working Capital Allowance	$3,181	$3,161	$3,141	$3,121	$3,101	$3,081	$3,061	$3,040	$3,020	$3,000
13	Rate Base	$1,790,651	$1,722,296	$1,653,942	$1,585,587	$1,517,233	$1,448,878	$1,380,524	$1,312,169	$1,243,815	$1,175,461
14	REVENUE DEFICIENCY										
15											
16	Cost of Gas	$819	$819	$819	$819	$819	$819	$819	$819	$819	$819
17	Operating & Maintenance Expenses	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161
18	Depreciation Expense	$84,782	$84,782	$84,782	$84,782	$84,782	$84,782	$84,782	$84,782	$84,782	$84,782
19	Amortization of Contributions	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)	($16,448)
20	Municipal Tax & Corp.Cap. Tax	$58,322	$57,899	$57,475	$57,051	$56,627	$56,203	$55,779	$55,355	$54,931	$54,507
21	Income Taxes	$66,022	$65,825	$65,548	$65,197	$64,773	$64,279	$63,719	$63,094	$62,408	$61,663
22	Overall Return	$145,043	$139,506	$133,969	$128,433	$122,896	$117,359	$111,822	$106,286	$100,749	$95,212
23	Total Revenue Requirement	$346,702	$340,543	$334,306	$327,994	$321,609	$315,155	$308,634	$302,049	$295,403	$288,697
24	Projected Revenues	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847	$156,847
25	Revenue Sufficiency (Deficiency)	($189,855)	($183,696)	($177,459)	($171,147)	($164,762)	($158,308)	($151,787)	($145,202)	($138,556)	($131,850)
26	Revenue to Cost Ratio	45.2%	46.1%	46.9%	47.8%	48.8%	49.8%	50.8%	51.9%	53.1%	54.3%

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1 **East Selkirk Generating Station Project - Initial True Up**

2		TIME 0 2001	YEAR 1 2002	YEAR 2 2003	YEAR 3 2004	YEAR 4 2005	YEAR 5 2006	YEAR 6 2007	YEAR 7 2008	YEAR 8 2009	YEAR 9 2010	YEAR 10 2011
3	**OPERATING ASSUMPTIONS**											
4	Number of Customers		1	1	1	1	1	1	1	1	1	1
5	Annual Volume (Mcf)		743,443	786,486	1,101,988	1,101,988	1,101,988	1,101,988	1,101,988	1,101,988	1,101,988	1,101,988
6	Annual Volume (10^3m^3)		21,060	22,279	31,217	31,217	31,217	31,217	31,217	31,217	31,217	31,217
7	Projected Revenues		$18,821	$821,226	$427,707	$427,707	$427,707	$427,707	$427,707	$427,707	$427,707	$427,707
8	**RATE BASE**											
9	Gross Fixed Assets	$4,743,074	$9,926,292	$10,002,654	$10,002,654	$10,002,654	$10,002,654	$10,002,654	$10,002,654	$10,002,654	$10,002,654	$10,002,654
10	Accumulated Depreciation		$150,622	$567,434	$920,429	$1,273,423	$1,626,417	$1,979,411	$2,332,405	$2,685,400	$3,038,394	$3,391,388
11	Contributions	$8,282,222	$8,026,577	$7,680,381	$7,387,190	$7,093,999	$6,800,809	$6,507,618	$6,214,427	$5,921,237	$5,628,046	$5,334,855
12	Working Capital Allowance		$6,553	$8,031	$10,888	$10,805	$10,722	$10,638	$10,555	$10,471	$10,388	$10,304
13	Rate Base		($888,475)	$1,759,997	$1,735,826	$1,675,939	$1,616,052	$1,556,165	$1,496,278	$1,436,391	$1,376,504	$1,316,617
14	**REVENUE DEFICIENCY**											
15												
16	Cost of Gas		$39,601	$38,663	$53,203	$53,203	$53,203	$53,203	$53,203	$53,203	$53,203	$53,203
17	Operating & Maintenance Expenses		$28,725	$28,725	$28,725	$28,725	$28,725	$28,725	$28,725	$28,725	$28,725	$28,725
18	Depreciation Expense		$150,622	$416,812	$352,994	$352,994	$352,994	$352,994	$352,994	$352,994	$352,994	$352,994
19	Amortization of Contributions		($255,645)	($346,197)	($293,191)	($293,191)	($293,191)	($293,191)	($293,191)	($293,191)	($293,191)	($293,191)
20	Municipal Tax & Corp.Cap. Tax		$127,888	$138,180	$148,463	$146,698	$144,933	$143,168	$141,403	$139,638	$137,873	$136,108
21	Income Taxes		($147,093)	$62,057	$51,510	$51,799	$52,000	$52,118	$52,156	$52,116	$52,002	$51,817
22	Overall Return		($79,015)	$151,204	$140,522	$135,673	$130,825	$125,977	$121,129	$116,281	$111,433	$106,585
23	Total Revenue Requirement		($134,917)	$489,445	$482,226	$475,902	$469,490	$462,995	$456,419	$449,766	$443,040	$436,242
24	Projected Revenues		$18,821	$821,226	$427,707	$427,707	$427,707	$427,707	$427,707	$427,707	$427,707	$427,707
25	Revenue Sufficiency (Deficiency)		$153,739	$331,781	($54,519)	($48,195)	($41,783)	($35,288)	($28,712)	($22,060)	($15,333)	($8,535)
26	Revenue to Cost Ratio		-14.0%	167.8%	88.7%	89.9%	91.1%	92.4%	93.7%	95.1%	96.5%	98.0%
27	NPV of Revenue Deficiency	$1										
28	**CONTRIBUTION REQUIREMENT**											
29	Total Contribution Required	$8,282,222										

Centra Gas Manitoba Inc.
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1 **East Selkirk Generating Station Project - Initial True Up**

		YEAR 11 2012	YEAR 12 2013	YEAR 13 2014	YEAR 14 2015	YEAR 15 2016	YEAR 16 2017	YEAR 17 2018	YEAR 18 2019	YEAR 19 2020	YEAR 20 2021
2											
3	OPERATING ASSUMPTIONS										
4	Number of Customers	1	1	1	1	1	1	1	1	0	0
5	Annual Volume (Mcf)	1,101,988	667,094	58,242	58,242	58,242	58,242	58,242	58,242	0	0
6	Annual Volume (10^3m^3)	31,217	18,897	1,650	1,650	1,650	1,650	1,650	1,650	0	0
7	Projected Revenues	$427,707	$335,742	$145,430	$145,430	$145,430	$145,430	$145,430	$145,430	$0	$0
8	RATE BASE										
9	Gross Fixed Assets	$10,002,654	$10,002,654	$10,002,654	$10,002,654	$10,002,654	$10,002,654	$10,002,654	$10,002,654	$0	$0
10	Accumulated Depreciation	$3,744,382	$4,097,376	$4,450,370	$4,803,365	$5,156,359	$5,509,353	$5,862,347	$6,215,341	$0	$0
11	Contributions	$5,041,665	$4,748,474	$4,455,283	$4,162,093	$3,868,902	$3,575,711	$3,282,521	$2,989,330	$0	$0
12	Working Capital Allowance	$10,221	$9,141	$7,661	$7,578	$7,494	$7,411	$7,328	$7,244	$0	$0
13	Rate Base	$1,256,730	$1,195,846	$1,134,563	$1,074,676	$1,014,789	$954,902	$895,016	$835,129	$0	$0
14	REVENUE DEFICIENCY										
15											
16	Cost of Gas	$53,203	$32,105	$2,568	$2,568	$2,568	$2,568	$2,568	$2,568	$0	$0
17	Operating & Maintenance Expenses	$28,725	$28,725	$28,725	$28,725	$28,725	$28,725	$28,725	$28,725	$0	$0
18	Depreciation Expense	$352,994	$352,994	$352,994	$352,994	$352,994	$352,994	$352,994	$352,994	$0	$0
19	Amortization of Contributions	($293,191)	($293,191)	($293,191)	($293,191)	($293,191)	($293,191)	($293,191)	($293,191)	$0	$0
20	Municipal Tax & Corp.Cap. Tax	$134,343	$132,578	$130,813	$129,048	$127,283	$125,518	$123,753	$121,988	$0	$0
21	Income Taxes	$51,564	$51,214	$50,788	$50,346	$49,846	$49,290	$48,681	$48,021	$0	$0
22	Overall Return	$101,737	$96,808	$91,847	$86,999	$82,151	$77,303	$72,455	$67,607	$0	$0
23	Total Revenue Requirement	$429,375	$401,234	$364,545	$357,490	$350,377	$343,208	$335,986	$328,712	$0	$0
24	Projected Revenues	$427,707	$335,742	$145,430	$145,430	$145,430	$145,430	$145,430	$145,430	$0	$0
25	Revenue Sufficiency (Deficiency)	($1,669)	($65,492)	($219,115)	($212,060)	($204,947)	($197,778)	($190,556)	($183,282)	$0	$0
26	Revenue to Cost Ratio	99.6%	83.7%	39.9%	40.7%	41.5%	42.4%	43.3%	44.2%	0.0%	0.0%

Centra Gas Manitoba Inc.
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1 **East Selkirk Generating Station Project - Initial True Up**

2		YEAR 21 2022	YEAR 22 2023	YEAR 23 2024	YEAR 24 2025	YEAR 25 2026	YEAR 26 2027	YEAR 27 2028	YEAR 28 2029	YEAR 29 2030	YEAR 30 2031
3	OPERATING ASSUMPTIONS										
4	Number of Customers	0	0	0	0	0	0	0	0	0	0
5	Annual Volume (Mcf)	0	0	0	0	0	0	0	0	0	0
6	Annual Volume (10^3m^3)	0	0	0	0	0	0	0	0	0	0
7	Projected Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	RATE BASE										
9	Gross Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Working Capital Allowance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Rate Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	REVENUE DEFICIENCY										
15											
16	Cost of Gas	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17	Operating & Maintenance Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Depreciation Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Amortization of Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	Municipal Tax & Corp.Cap. Tax	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	Overall Return	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Total Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Projected Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Revenue Sufficiency (Deficiency)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Revenue to Cost Ratio	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Financial Feasibility Test
for Natural Gas Expansion

1 **Brandon Combustion Turbine - True Up as of July 31, 2008**

		TIME 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
2		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
3	OPERATING ASSUMPTIONS											
4	Number of Customers		1	1	1	1	1	1	1	1	1	1
5	Annual Volume (Mcf)		1,280,259	1,436,131	374,234	134,013	328,159	488,474	241,285	488,474	488,474	488,474
6	Annual Volume (10^3m^3)		36,267	40,682	10,601	3,796	9,296	13,837	6,835	13,837	13,837	13,837
7	Projected Revenues		$224,506	$653,538	$817,557	$652,426	$561,860	$829,115	$938,350	$1,308,986	$1,308,986	$1,308,986
8	RATE BASE											
9	Gross Fixed Assets	$3,955,471	$3,955,471	$3,956,301	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850
10	Accumulated Depreciation		$77,191	$172,640	$259,012	$345,385	$430,958	$516,530	$599,304	$682,077	$764,851	$847,625
11	Contributions	$198,695	$194,806	$189,998	$185,706	$181,414	$177,162	$172,910	$168,797	$164,684	$160,571	$156,458
12	Working Capital Allowance		$4,766	$5,554	$5,496	$4,462	$6,035	$14,796	$21,467	$38,965	$38,946	$38,926
13	Rate Base		$3,724,891	$3,644,123	$3,585,394	$3,529,553	$3,449,426	$3,376,866	$3,303,547	$3,242,384	$3,163,704	$3,085,024
14	REVENUE DEFICIENCY											
15												
16	Cost of Gas		$67,684	$66,588	$39,066	$24,342	$50,284	$224,146	$365,714	$736,386	$736,386	$736,386
17	Operating & Maintenance Expenses		$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161
18	Depreciation Expense		$77,191	$95,449	$86,372	$86,372	$85,573	$85,573	$82,774	$82,774	$82,774	$82,774
19	Amortization of Contributions		($3,889)	($4,808)	($4,292)	($4,292)	($4,252)	($4,252)	($4,113)	($4,113)	($4,113)	($4,113)
20	Municipal Tax & Corp.Cap. Tax		$66,852	$67,405	$69,072	$67,932	$77,414	$80,767	$80,353	$79,939	$79,525	$79,112
21	Income Taxes		$122,085	$70,305	$0	$0	$0	$0	$0	$0	$0	$0
22	Overall Return		$331,269	$313,073	$290,417	$285,894	$264,958	$244,010	$238,712	$234,292	$228,607	$222,921
23	Total Revenue Requirement		$669,352	$616,173	$488,797	$468,410	$482,137	$638,404	$771,600	$1,137,439	$1,131,339	$1,125,240
24	Projected Revenues		$224,506	$653,538	$817,557	$652,426	$561,860	$829,115	$938,350	$1,308,986	$1,308,986	$1,308,986
25	Revenue Deficiency (Annual)		($444,845)	$37,365	$328,760	$184,016	$79,723	$190,711	$166,749	$171,547	$177,646	$183,745
26	Revenue to Cost Ratio		33.5%	106.1%	167.3%	139.3%	116.5%	129.9%	121.6%	115.1%	115.7%	116.3%
27	NPV of Revenue Deficiency	1										
28	CONTRIBUTION REQUIREMENT											
29	Total Contribution Required	$198,695										

Financial Feasibility Test
for Natural Gas Expansion

1 **Brandon Combustion Turbine - True Up as of July 31, 2008**

		YEAR 11 2012	YEAR 12 2013	YEAR 13 2014	YEAR 14 2015	YEAR 15 2016	YEAR 16 2017	YEAR 17 2018	YEAR 18 2019	YEAR 19 2020	YEAR 20 2021
2											
3	OPERATING ASSUMPTIONS										
4	Number of Customers	1	1	1	1	1	1	1	1	1	1
5	Annual Volume (Mcf)	488,474	289,528	11,004	11,004	11,004	11,004	11,004	11,004	11,004	11,004
6	Annual Volume (10^3m^3)	13,837	8,202	312	312	312	312	312	312	312	312
7	Projected Revenues	$1,308,986	$909,056	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595
8	RATE BASE										
9	Gross Fixed Assets	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850
10	Accumulated Depreciation	$930,398	$1,013,172	$1,095,945	$1,178,719	$1,261,493	$1,344,266	$1,427,040	$1,509,813	$1,592,587	$1,675,360
11	Contributions	$152,345	$148,232	$144,119	$140,006	$135,893	$131,780	$127,667	$123,554	$119,441	$115,328
12	Working Capital Allowance	$38,907	$24,713	$4,850	$4,831	$4,811	$4,792	$4,772	$4,753	$4,733	$4,713
13	Rate Base	$3,006,344	$2,913,490	$2,814,966	$2,736,286	$2,657,606	$2,578,926	$2,500,246	$2,421,566	$2,342,886	$2,264,205
14	REVENUE DEFICIENCY										
15											
16	Cost of Gas	$736,386	$436,475	$16,599	$16,599	$16,599	$16,599	$16,599	$16,599	$16,599	$16,599
17	Operating & Maintenance Expenses	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161
18	Depreciation Expense	$82,774	$82,774	$82,774	$82,774	$82,774	$82,774	$82,774	$82,774	$82,774	$82,774
19	Amortization of Contributions	($4,113)	($4,113)	($4,113)	($4,113)	($4,113)	($4,113)	($4,113)	($4,113)	($4,113)	($4,113)
20	Municipal Tax & Corp.Cap. Tax	$78,698	$78,284	$77,870	$77,456	$77,042	$76,628	$76,215	$75,801	$75,387	$74,973
21	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	Overall Return	$217,236	$210,526	$203,407	$197,722	$192,036	$186,351	$180,666	$174,980	$169,295	$163,610
23	Total Revenue Requirement	$1,119,141	$812,107	$384,698	$378,599	$372,500	$366,401	$360,301	$354,202	$348,103	$342,004
24	Projected Revenues	$1,308,986	$909,056	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595
25	Revenue Deficiency (Annual)	$189,845	$96,950	($210,103)	($204,004)	($197,905)	($191,805)	($185,706)	($179,607)	($173,508)	($167,409)
26	Revenue to Cost Ratio	117.0%	111.9%	45.4%	46.1%	46.9%	47.7%	48.5%	49.3%	50.2%	51.1%

Financial Feasibility Test
for Natural Gas Expansion

1 **Brandon Combustion Turbine - True Up as of July 31, 2008**

		YEAR 21	YEAR 22	YEAR 23	YEAR 24	YEAR 25	YEAR 26	YEAR 27	YEAR 28	YEAR 29	YEAR 30
2		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
3	OPERATING ASSUMPTIONS										
4	Number of Customers	1	1	1	1	1	1	1	1	1	1
5	Annual Volume (Mcf)	11,004	11,004	11,004	11,004	11,004	11,004	11,004	11,004	11,004	11,004
6	Annual Volume (10^3m^3)	312	312	312	312	312	312	312	312	312	312
7	Projected Revenues	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595
8	RATE BASE										
9	Gross Fixed Assets	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850	$4,010,850
10	Accumulated Depreciation	$1,758,134	$1,840,908	$1,923,681	$2,006,455	$2,089,228	$2,172,002	$2,254,776	$2,337,549	$2,420,323	$2,503,096
11	Contributions	$111,215	$107,102	$102,989	$98,876	$94,763	$90,650	$86,537	$82,424	$78,311	$74,198
12	Working Capital Allowance	$4,694	$4,674	$4,655	$4,635	$4,616	$4,596	$4,577	$4,557	$4,537	$4,518
13	Rate Base	$2,185,525	$2,106,845	$2,028,165	$1,949,485	$1,870,805	$1,792,124	$1,713,444	$1,634,764	$1,556,084	$1,477,404
14	REVENUE DEFICIENCY										
15											
16	Cost of Gas	$16,599	$16,599	$16,599	$16,599	$16,599	$16,599	$16,599	$16,599	$16,599	$16,599
17	Operating & Maintenance Expenses	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161	$8,161
18	Depreciation Expense	$82,774	$82,774	$82,774	$82,774	$82,774	$82,774	$82,774	$82,774	$82,774	$82,774
19	Amortization of Contributions	($4,113)	($4,113)	($4,113)	($4,113)	($4,113)	($4,113)	($4,113)	($4,113)	($4,113)	($4,113)
20	Municipal Tax & Corp.Cap. Tax	$74,559	$74,145	$73,731	$73,317	$72,904	$72,490	$72,076	$71,662	$71,248	$70,834
21	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	Overall Return	$157,924	$152,239	$146,554	$140,868	$135,183	$129,497	$123,812	$118,127	$112,441	$106,756
23	Total Revenue Requirement	$335,904	$329,805	$323,706	$317,607	$311,507	$305,408	$299,309	$293,210	$287,111	$281,011
24	Projected Revenues	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595	$174,595
25	Revenue Deficiency (Annual)	($161,309)	($155,210)	($149,111)	($143,012)	($136,912)	($130,813)	($124,714)	($118,615)	($112,515)	($106,416)
26	Revenue to Cost Ratio	52.0%	52.9%	53.9%	55.0%	56.0%	57.2%	58.3%	59.5%	60.8%	62.1%

Financial Feasibility Test
for Natural Gas Expansion

1 **Selkirk Generating Station Project - True Up as of July 31, 2008**

2		TIME 0 2001	YEAR 1 2002	YEAR 2 2003	YEAR 3 2004	YEAR 4 2005	YEAR 5 2006	YEAR 6 2007	YEAR 7 2008	YEAR 8 2009	YEAR 9 2010	YEAR 10 2011
3	OPERATING ASSUMPTIONS											
4	Number of Customers		1	1	1	1	1	1	1	1	1	1
5	Annual Volume (Mcf)		743,443	1,533,665	747,370	23,594	67,646	299,702	476,127	1,101,988	1,101,988	1,101,988
6	Annual Volume (10^3m^3)		21,060	43,445	21,171	668	1,916	8,490	13,488	31,217	31,217	31,217
7	Projected Revenues		$50,438	$929,311	$594,352	$561,928	$518,380	$465,631	$1,051,652	$2,018,233	$2,018,233	$2,018,233
8	RATE BASE											
9	Gross Fixed Assets	$4,743,074	$9,926,292	$10,079,662	$10,085,653	$10,085,653	$10,085,653	$10,085,653	$10,085,653	$10,085,653	$10,085,653	$10,085,653
10	Accumulated Depreciation		$150,622	$565,087	$917,783	$1,270,479	$1,619,179	$1,967,879	$2,305,588	$2,643,297	$2,981,006	$3,318,715
11	Contributions	$7,802,845	$7,561,997	$7,238,179	$6,962,739	$6,687,298	$6,414,979	$6,142,660	$5,878,923	$5,615,187	$5,351,451	$5,087,715
12	Working Capital Allowance		$6,553	$9,571	$10,793	$8,893	$9,602	$12,584	$43,088	$87,085	$87,005	$86,926
13	Rate Base		($416,496)	$2,254,606	$2,251,557	$2,175,397	$2,099,288	$2,025,890	$1,981,217	$1,951,241	$1,877,188	$1,803,136
14	REVENUE DEFICIENCY											
15												
16	Cost of Gas		$39,601	$74,162	$45,317	$12,692	$16,077	$63,957	$711,078	$1,643,729	$1,643,729	$1,643,729
17	Operating & Maintenance Expenses		$28,725	$28,725	$28,725	$28,725	$28,725	$28,725	$28,725	$28,725	$28,725	$28,725
18	Depreciation Expense		$150,622	$414,465	$352,696	$352,696	$348,700	$348,700	$337,709	$337,709	$337,709	$337,709
19	Amortization of Contributions		($240,848)	($323,818)	($275,440)	($275,440)	($272,319)	($272,319)	($263,736)	($263,736)	($263,736)	($263,736)
20	Municipal Tax & Corp.Cap. Tax		$127,888	$142,102	$154,323	$158,762	$171,340	$173,597	$171,909	$170,220	$168,531	$166,843
21	Income Taxes		($126,993)	$78,920	$0	$0	$0	$0	$0	$0	$0	$0
22	Overall Return		($37,041)	$193,697	$182,376	$176,207	$161,251	$146,389	$143,161	$140,995	$135,644	$130,293
23	Total Revenue Requirement		($58,045)	$608,254	$487,997	$453,641	$453,773	$489,049	$1,128,846	$2,057,642	$2,050,602	$2,043,563
24	Projected Revenues		$50,438	$929,311	$594,352	$561,928	$518,380	$465,631	$1,051,652	$2,018,233	$2,018,233	$2,018,233
25	Revenue Sufficiency (Deficiency)		$108,482	$321,057	$106,355	$108,286	$64,607	($23,418)	($77,194)	($39,409)	($32,369)	($25,330)
26	Revenue to Cost Ratio		-86.9%	152.8%	121.8%	123.9%	114.2%	95.2%	93.2%	98.1%	98.4%	98.8%
27	NPV of Revenue Deficiency	1										
28	CONTRIBUTION REQUIREMENT											
29	Total Contribution Required	$7,802,845										

Financial Feasibility Test
for Natural Gas Expansion

1 **Selkirk Generating Station Project - True Up as of July 31, 2008**

2		YEAR 11	YEAR 12	YEAR 13	YEAR 14	YEAR 15	YEAR 16	YEAR 17	YEAR 18	YEAR 19	YEAR 20
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
3	OPERATING ASSUMPTIONS										
4	Number of Customers	1	1	1	1	1	1	1	1	0	0
5	Annual Volume (Mcf)	1,101,988	667,094	58,242	58,242	58,242	58,242	58,242	58,242	0	0
6	Annual Volume (10^3m^3)	31,217	18,897	1,650	1,650	1,650	1,650	1,650	1,650	0	0
7	Projected Revenues	$2,018,233	$1,336,305	$239,145	$239,145	$239,145	$239,145	$239,145	$239,145	$0	$0
8	RATE BASE										
9	Gross Fixed Assets	$10,085,653	$10,085,653	$10,085,653	$10,085,653	$10,085,653	$10,085,653	$10,085,653	$10,085,653	$0	$0
10	Accumulated Depreciation	$3,656,424	$3,994,133	$4,331,842	$4,669,551	$5,007,260	$5,344,970	$5,682,679	$6,020,388	$0	$0
11	Contributions	$4,823,979	$4,560,243	$4,296,506	$4,032,770	$3,769,034	$3,505,298	$3,241,562	$2,977,826	$0	$0
12	Working Capital Allowance	$86,846	$56,106	$13,101	$13,021	$12,942	$12,862	$12,782	$12,702	$0	$0
13	Rate Base	$1,729,083	$1,624,370	$1,507,392	$1,433,340	$1,359,287	$1,285,234	$1,211,181	$1,137,129	$0	$0
14	REVENUE DEFICIENCY										
15											
16	Cost of Gas	$1,643,729	$994,971	$86,711	$86,711	$86,711	$86,711	$86,711	$86,711	$0	$0
17	Operating & Maintenance Expenses	$28,725	$28,725	$28,725	$28,725	$28,725	$28,725	$28,725	$28,725	$0	$0
18	Depreciation Expense	$337,709	$337,709	$337,709	$337,709	$337,709	$337,709	$337,709	$337,709	$0	$0
19	Amortization of Contributions	($263,736)	($263,736)	($263,736)	($263,736)	($263,736)	($263,736)	($263,736)	($263,736)	$0	$0
20	Municipal Tax & Corp.Cap. Tax	$165,154	$163,466	$161,777	$160,089	$158,400	$156,712	$155,023	$153,335	$0	$0
21	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	Overall Return	$124,942	$117,376	$108,923	$103,572	$98,221	$92,870	$87,519	$82,168	$0	$0
23	Total Revenue Requirement	$2,036,523	$1,378,511	$460,110	$453,070	$446,030	$438,991	$431,951	$424,912	$0	$0
24	Projected Revenues	$2,018,233	$1,336,305	$239,145	$239,145	$239,145	$239,145	$239,145	$239,145	$0	$0
25	Revenue Sufficiency (Deficiency)	($18,290)	($42,206)	($220,965)	($213,925)	($206,886)	($199,846)	($192,806)	($185,767)	$0	$0
26	Revenue to Cost Ratio	99.1%	96.9%	52.0%	52.8%	53.6%	54.5%	55.4%	56.3%	0.0%	0.0%

1 **Selkirk Generating Station Project - True Up as of July 31, 2008**

		YEAR 21	YEAR 22	YEAR 23	YEAR 24	YEAR 25	YEAR 26	YEAR 27	YEAR 28	YEAR 29	YEAR 30
2		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
3	OPERATING ASSUMPTIONS										
4	Number of Customers	0	0	0	0	0	0	0	0	0	0
5	Annual Volume (Mcf)	0	0	0	0	0	0	0	0	0	0
6	Annual Volume (10^3m^3)	0	0	0	0	0	0	0	0	0	0
7	Projected Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	RATE BASE										
9	Gross Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Accumulated Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Working Capital Allowance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Rate Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	REVENUE DEFICIENCY										
15											
16	Cost of Gas	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17	Operating & Maintenance Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Depreciation Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Amortization of Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	Municipal Tax & Corp.Cap. Tax	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	Overall Return	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Total Revenue Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Projected Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Revenue Sufficiency (Deficiency)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Revenue to Cost Ratio	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

PUB/CENTRA II-182

Reference: PUB/Centra I-119; Tab 11 Schedule 11.1.0

c) Please explain why only $389,273 is allocated to the Power Station class if the combined MAGMA is $947,100 for the two customers in this class.

ANSWER:

The annual allocation of cost to the Power Station Class and the Minimum Margin Guarantee serve different purposes. The $389,000 represents this year's allocated portion of embedded cost to the Power Stations based their forecasted load data for the 2013/14 Test Year and is consistent with the allocation of costs to all other customer classes.

The Minimum Margin Guarantee of $947,000 is a contractual provision contained in the Power Station Contracts. It was put in place to provide a predictable revenue stream to Centra recognizing the potential highly variable use profile of the customers. This revenue, combined with the customer contributions received from the Power Stations ensures that incremental investment made to serve them will be recovered. The Minimum Margin Guarantee was established as part of Centra's 2003/04 GRA and was based on the anticipated normal demand and usage forecasted for the Power Stations at that time. The Minimum Margin Guarantee comes into effect if actual billings to the Power Stations in a year are less than the minimum of $947,000.

PUB/CENTRA II-182

Reference: PUB/Centra I-119; Tab 11 Schedule 11.1.0

d) Please provide the forecasted Test Year revenue to cost ratio for this customer reflecting the anticipated revenue from the MAGMA.

ANSWER:

Please refer to the tables below.

i) Forecast RCC with all revenues included:

Cost Allocation	2013/14 GRA
Energy	125,157
Demand	67,332
Customer	196,785
Total Allocated costs	389,273
Revenue	
Energy	125,157
Minimum Annual Gross Margin	947,104
Total Revenue	1,072,261
Revenue To Cost Ratio	
Total Revenue	1,072,261
Total Allocated costs	389,273
Revenue To Cost Ratio:	2.8

ii) Forecast RCC excluding top-up payment to assure MAGMA:

Cost Allocation	2013/14 GRA
Energy	125,157
Demand	67,332
Customer	196,785
Total Allocated costs	389,273
Revenue	
Energy	125,157
Minimum Annual Gross Margin (MAGMA)	947,104
Total Revenue	1,072,261
Minimum Annual Gross Margin	947,104
Less: Demand	-67,332
Less: Customer	-196,785
Top-up payment to MAGMA	682,988
Revenue To Cost Ratio	
Total Revenue	1,072,261
Less: Top-up payment to MAGMA	-682,988
PS Revenue before Top-up payment	389,273
Total Allocated costs	389,273
Revenue To Cost Ratio:	1.0

PUB/CENTRA II-182

Reference: PUB/Centra I-119; Tab 11 Schedule 11.1.0

e) Please give Centra's view on whether the allocations to the Power Station class should be adjusted such that Centra's Cost Allocation Model allocates a greater share of cost to the Power Station customer, reflecting the cost to serve this customer as originally established by the contract and the MAGMA.

ANSWER:

Please see Centra's response to PUB/Centra II-182(c).

PUB/CENTRA II-183

Reference: PUB/Centra I-123 FRPGS

a) In the case where Centra finds that there is a concentrated number of contracts clustered in a single set of offerings, please explain what mitigating actions Centra can take.

ANSWER:

In the event that any of the thresholds are reached, the protocol will be followed as outlined in Centra's responses to PUB/Centra I-123(e) and (f).

PUB/CENTRA II-183

Reference: PUB/Centra I-123 FRPGS

b) If the 2.5% overall annual sales volume threshold triggers a review of the program, please indicate what mitigating actions Centra may take.

ANSWER:

Please see Centra's response to PUB/Centra 1-183(d) for discussion of the alternatives available to Centra in the event that any of the program review thresholds is reached.

PUB/CENTRA II-183

Reference: PUB/Centra I-123 FRPGS

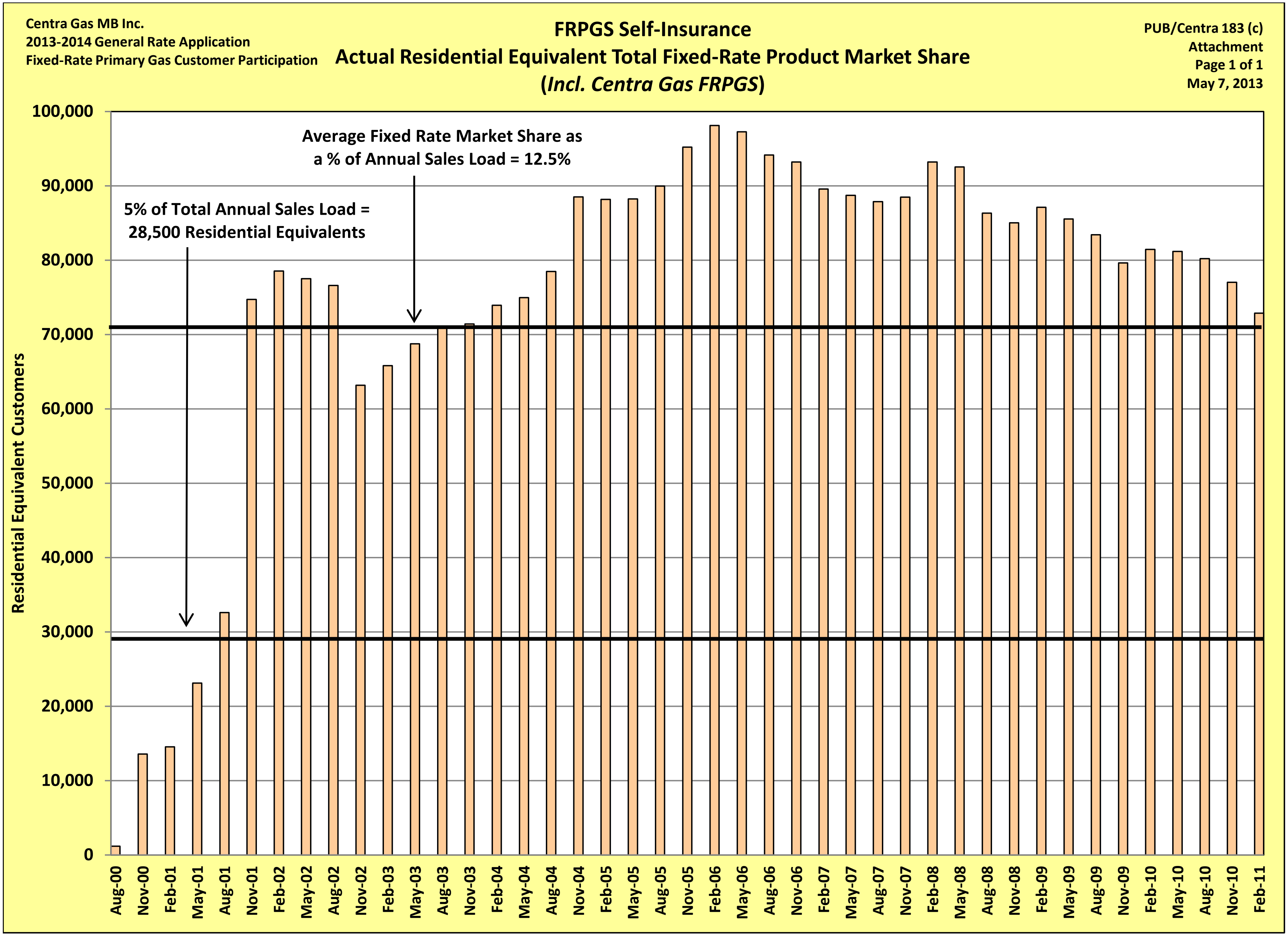
c) Please explain how Centra determined that an annual limit of the total active customers under FRPGS contract of 5% of overall annual sales is a manageable financial risk. Provide any analysis in support of this determination.

ANSWER:

A cap on total active customers under FRPGS contract of 5% of overall annual sales volumes serves to limit Centra's overall financial risk associated with the FRPGS, while also allowing Centra to accommodate total customer demand under the program that represents 40% of the average of 12.5% of overall annual sales volume contracted on a fixed Primary Gas rate (marketers and Centra combined) during the period from May 1, 2000 through March 31, 2011.

Please see the attached chart that depicts overall fixed-rate Primary Gas customer participation, in residential customer equivalents, during the aforementioned period.

As stated in the response to PUB/Centra I-122(c) and PUB/Centra I-123(e), Centra believes that a cap of 5% of overall annual sales volumes under FRPGS contract, combined with the remaining three supplementary risk mitigation thresholds, along with an 8% SRP, provides for a reasonably robust program for managing Centra's financial risks under the FRPGS given the highly volatile market conditions during the historical period over which the SRP was modeled and tested.



Centra Gas MB Inc.
2013-2014 General Rate Application
Fixed-Rate Primary Gas Customer Participation
FRPGS Self-Insurance
Actual Residential Equivalent Total Fixed-Rate Product Market Share
(Incl. Centra Gas FRPGS)
PUB/Centra 183 (c)
Attachment
Page 1 of 1
May 7, 2013
Average Fixed Rate Market Share as a % of Annual Sales Load = 12.5%
5% of Total Annual Sales Load = 28,500 Residential Equivalents
Residential Equivalent Customers
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Aug-00
Nov-00
Feb-01
May-01
Aug-01
Nov-01
Feb-02
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Nov-10
Feb-11

PUB/CENTRA II-183

Reference: PUB/Centra I-123 FRPGS

d) With respect to the final two thresholds related to settled and unsettled margin losses of greater than $1 million, please discuss the actions that Centra can take in order to limit the continued growth in the program's potential financial losses.

ANSWER:

The alternatives available to Centra in order limit the continued growth in settled or unsettled risk margin losses in the event that either of $1 million thresholds is reached would be dependent upon the particular circumstances encountered at the time.

For example, in a case where settled risk margin losses were to reach the $1 million threshold, while unsettled risk margin is in a gain position that offsets all or a significant portion of settled losses, it may be acceptable to allow settled risk margin results to exceed the $1 million threshold and continue to accept new customers into the FRPGS. The same may also hold in cases where unsettled risk margin losses reach $1 million, while at the same time settled risk margin gains offset all or a significant portion of unsettled losses.

Depending on the relationship between settled and unsettled risk margin results at the time either of the $1 million thresholds are reached, Centra could also elect to close the FRPGS to new customer subscriptions until such time as risk margin results have returned to within these thresholds.

Another alternative available to Centra could be the placement of hedging instruments in order to either lock-in its unsettled risk margin gain position, or to prevent further deterioration of existing unsettled risk margin losses. This alternative would only be viable in cases where the unsettled volumes involved are of a sufficient magnitude to allow the economic placement of hedges.

Similar factors and alternatives would be considered in the event that either quarterly customer migration to the FRPGS reaches 0.5%, or total customers under FRPGS contract reaches 2.5% of Centra's overall annual sales volume.

In the event that any of the FRPGS program target risk thresholds are reached, the protocol will be followed as outlined in Centra's responses to PUB/Centra I-123(e) and (f).

PUB/CENTRA II-184

Reference: PUB/Centra I-127 – FRPGS Mark to Market

In light of the reported updated settled and unsettled results, please indicate to what level the balances have to reach to trigger the proposed review of the program based on the million-dollar threshold established

ANSWER:

Please see the table below. The proposed $1 million threshold includes results of the FRPGS offerings that did not use hedging instruments (i.e. commencing with the November 1, 2011 flow offering). Please note that the information contained in the referenced response to PUB/Centra I-127 reflects FRPGS hedging impacts only. As the $1 million settled and unsettled thresholds are with respect to risk margin results (i.e. Total FRPGS program revenues less program cost rate revenues, minus FRPGS WACOG, plus or minus hedging impacts if applicable), additional information has been included in the table in order to illustrate risk margin results as at March 31, 2013.

FRPGS Risk Margin as March 31, 2013
Relative to $1 Million Risk Margin Thresholds Calculated From the Inception of Self-Insurance

	Settled	Unsettled Mark-to-Market
FRPGS Revenue (Not Incl. Program Cost Rate Revenue)	$2,470,355	$1,382,521
Less FRPGS WACOG	$1,500,592	$1,045,607
FRPGS Gross Margin (Not Incl. Program Cost Rate Revenue & Hedge Impacts)	$969,763	$336,914
Hedging Impact	($1,512,945)	($336,089)
Risk Margin as @ March 31, 2013	**($543,182)**	**$825**
Risk Margin on Unhedged Offerings From November 2011 through February 2013 (Included Above)	$50,146	$29,282
Further Deterioration in Risk Margin Required to Reach $1 Million Threshold	($1,050,146)	($1,029,282)
Net Risk Margin Balance @ $1 Million Threshold Calculated From the Inception of Self-Insurance	**($1,593,328)**	**($1,028,457)**

PUB/CENTRA II-185

Reference: PUB/Centra I-129

a) In response to PUB/Centra I-129(a), (d), and (e), Centra advises that it currently does not track or invoice incident investigation and appliance relight costs. Please confirm whether Centra has an estimate or projection of the total annual incident investigation and appliance relight costs it expects to invoice if the PUB approves such invoicing. If confirmed, please provide.

ANSWER:

Centra does not forecast the number of third party damages, and as such does not have an estimate or projection of the total annual costs related to incident investigation and relights. The amount of costs that would be recovered will be specific to the event and will be dependent on the severity, nature and location.

PUB/CENTRA II-185

Reference: PUB/Centra I-129

b) Please confirm whether the new activity rates for third party damages will be charged to Manitoba Hydro electric operations in instances where Manitoba Hydro or its contractors damage Centra's plant.

ANSWER:

In instances where Manitoba Hydro or its contractors damage Centra's plant, charges related to the new activity rates pertaining to incident investigation and relights will be assessed and recovered in the same manner as a third party damage.

PUB/CENTRA II-186

Reference: PUB/Centra I-134

a) Please confirm the rate of return and the reference to its source used in the feasibility tests for the main extensions on Bergen Road – Rosser (MER 2010-00111), Portage La Prairie (MER 2011-00005), and Pine Drive – La Broquerie (MER 2012-00139).

ANSWER:

The Rate of Return used in the feasibility test for Bergen Road – Rosser (MER 2010-00111) was 6.08% for years 2 through 30. The Rate of Return for Year One had not been updated and was 7.23%. The contribution requirement did not change when the Rate of Return in Year One was changed to 6.08%.

The Rate of Return used in the feasibility tests for Portage La Prairie (MER 2011-00005), and Pine Drive – La Broquerie (MER 2012-00139) is 6.08%.

This rate is based upon Schedule 5.7.4 Overall Rate of Return Reflecting Order 128/09 & 41/10 - 2010/11 Test Year. This revised schedule was filed with the PUB on April 29, 2010 and approved in Order 46/10.

PUB/CENTRA II-186

Reference: PUB/Centra I-134

b) If the rate of return used in Centra's feasibility test is less than it should be, please explain the implications to Centra or to its customers.

ANSWER:

Centra's feasibility test is used to evaluate the financial feasibility of a proposed expansion to a new franchise area or a main extension in an existing franchise area. The feasibility test is by nature an incremental test that includes an estimate of the revenues and costs associated with the extension. If the revenues from the extension are not sufficient to make it financially feasible (i.e. the 30 year Net Present Value is negative and/or the revenue-to-cost ratio is less than 1.0 by the end of year 5), then the feasibility test determines an amount that is payable by the customer. This customer contribution is, over the long-run, considered to make the proposed extension financially feasible.

Using a lower rate of return in the feasibility test, all else being equal, will result in a lower calculated revenue deficiency and in some cases a lower customer contribution, if a contribution is required. The reverse would occur if a higher rate of return is used. For example, the MER (2010-00111) referenced in PUB/Centra II-186 (a) inadvertently included a higher rate of return in the first year of the test, but did not result in a change in the customer contribution.

PUB/CENTRA II-186

Reference: PUB/Centra I-134

c) Please explain how the number of lead days used in the feasibility test is derived from the lead days of 39.7, 15.2, and 17.7 for Purchased Gas, OM&A, and Taxes, respectively.

ANSWER:

The lead (lag) days used in the feasibility test is not solely derived from the lead days referenced for Purchased Gas, OM&A, and Taxes, but rather is the weighted average for all the Cash Revenue Requirement Items and it is based on Schedule 5.6.4 - Working Capital Allowance for the 2008/09 Test Year updated reflecting Order 99/07.

PUB/CENTRA II-186

Reference: PUB/Centra I-134

d) Please confirm whether the lead days used in the working capital calculation is in fact 15 and not 17.3.

ANSWER:

Centra confirms that the number of lead (lag) days used in the working capital calculation is 15. In the feasibility test this lead (lag) day value is applied to the Cost of Gas, Operating and Maintenance, and Municipal and Corporate Tax. There is an additional input into the working capital calculation of 15% to approximate the Non-Cost of Service Tax Collections in the project.

PUB/CENTRA II-186

Reference: PUB/Centra I-134

e) Please identify the origin or demonstrate the determination of the composite depreciation rate used in the feasibility test.

ANSWER:

The depreciation rate of 2.88% used in the feasibility test is based on depreciable distribution plant and associated depreciation expense as per Schedules 4.9.4 and 5.1.4 filed as part of the 2009/10 & 2010/11 General Rate Application, updated on May 29, 2009, and which were approved by Order 128/09. Only the categories pertaining to expansion projects are included in the calculation.

The following table outlines the calculation used to arrive at the 2.88% depreciation rate using the above noted schedules:

Depreciation Rate Calculation - for Main Extensions
Excludes Transmission Mains
Based upon: 2010/11 Test Year approved Board Order 128/09

	Balance Mar 31/10 per Sched. 5.1.4 (2010/11 Forecast) $000's	Balance Mar 31/11 per Sched. 5.1.4 (2010/11 Forecast) $000's	Average Plant	Expense per Sched. 4.9.4 (2010/11 Forecast) $000's	Average Depreciation Rate
	A	B	C =(A+B)/2	D	E = D/C
Distribution					
Land Rights	652	652	652	8	
Structures & Improvements	1,342	1,342	1,342	43	
Structures & Improvements-M&R	3,963	4,257	4,110	65	
Service Lines	204,040	211,233	207,637	6,920	
Regulators	45,798	48,029	46,914	1,223	
Reg. & Meter Installations	0	0	0	0	
Mains - Distribution	159,077	166,590	162,834	2,943	
Meas. & Reg. Equipment	34,630	36,392	35,511	1,464	
Telemetry Equipment	4,042	4,052	4,047	181	
Meters	40,472	41,922	41,197	1,674	
AMR/ERT modules	89	89	89	0	
Other Distribution Equipment	89	89	89	0	
Total	494,194	514,647	504,421	14,521	2.88%

PUB/CENTRA II-187

Reference: CAC/Centra I-26; 2011/12 COG PUB/Centra 8(c)

Please file a table showing the forecast Primary Gas supply price at Empress, the forecast AECO 7A price, the forecast transportation adder, the strip date, the actual Primary Gas supply price at Empress, the settled AECO 7A price, and the actual transportation adder in a similar format to 2011/12 COG PUB/Centra 8(c).

ANSWER:

Please see the attachment to this response. Please note that Centra did not file a purchased gas cost forecast with the PUB for the 2011/12 Gas Year, therefore no forecast is provided for the 2011/12 Gas Year in the attachment to this response.

AECO 7A to Empress Transportation Component - Forecast vs. Actual Comparison

	Forecast					**Actual**		
	Avg.Primary Supply -$/GJ	**AECO-7A**	**Adder**	**Strip date**	**Application**	**Avg.Primary Supply -$/GJ**	**AECO-7A**	**Adder/Discount**
Nov-10	$3.38	$3.20	$0.18	1-Nov-10	2011/12 COG	$3.54	$3.20	$0.34
Dec-10	$3.64	$3.47	$0.17	1-Nov-10	2011/12 COG	$3.82	$3.60	$0.21
Jan-11	$3.63	$3.47	$0.16	1-Nov-10	2011/12 COG	$3.88	$3.67	$0.20
Feb-11	$3.66	$3.48	$0.19	1-Nov-10	2011/12 COG	$3.77	$3.70	$0.07
Mar-11	$3.62	$3.45	$0.17	1-Nov-10	2011/12 COG	$3.63	$3.36	$0.27
Apr-11	$3.57	$3.39	$0.18	1-Nov-10	2011/12 COG	$3.60	$3.44	$0.16
May-11	$3.54	$3.38	$0.17	1-Nov-10	2011/12 COG	$3.70	$3.54	$0.16
Jun-11	$3.57	$3.40	$0.17	1-Nov-10	2011/12 COG	$3.83	$3.66	$0.18
Jul-11	$3.60	$3.45	$0.16	1-Nov-10	2011/12 COG	$3.87	$3.72	$0.16
Aug-11	$3.66	$3.50	$0.16	1-Nov-10	2011/12 COG	$3.62	$3.45	$0.16
Sep-11	$3.72	$3.56	$0.17	1-Nov-10	2011/12 COG	$3.52	$3.41	$0.12
Oct-11	$3.83	$3.65	$0.18	1-Nov-10	2011/12 COG	$3.43	$3.46	($0.03)
10/11 Gas Year Average	**$3.62**	**$3.45**	**$0.17**			**$3.68**	**$3.52**	**$0.17**
Nov-11						$3.10	$3.19	($0.09)
Dec-11						$3.02	$3.21	($0.18)
Jan-12						$2.64	$2.86	($0.22)
Feb-12						$2.12	$2.32	($0.20)
Mar-12						$1.84	$1.97	($0.14)
Apr-12						$1.56	$1.71	($0.15)
May-12						$1.59	$1.56	$0.03
Jun-12						$2.04	$1.95	$0.09
Jul-12						$2.05	$1.90	$0.16
Aug-12						$2.40	$2.28	$0.12
Sep-12						$2.26	$2.06	$0.20
Oct-12						$2.83	$2.34	$0.49
11/12 Gas Year Average						**$2.29**	**$2.28**	**$0.01**

PUB/CENTRA II-188

Reference: CAC/Centra I-27

Tab 10 pages 9 and 16 and Appendix 10.2 show Centra forecasting to use Primary Gas Delivered Service. CAC/Centra I-27 states that Centra is not forecasting the use of Primary Gas Delivered Service.

If Centra is only forecasting to use Primary Gas Delivered Service in colder-than-normal weather, please explain whether the Primary Gas Delivered Service is contracted prior to the start of the gas year, and if so, whether there are any costs that should be included in the gas cost forecast. If Centra forecasts the use of Primary Gas Delivered Service under normal weather, please explain the discrepancy between Tab 10 and CAC/Centra I-27.

ANSWER:

For the purpose of forecasting costs for the 2012/13 gas year, it was assumed that Centra's normal weather Primary Gas supply requirements would be met using Primary Gas supplied at Empress and transported using FT and STFT, recognizing that Primary Gas Delivered Service, as a short-term service, may also be used in place of Primary Gas transported on STFT.

Appendix 10.2 and the commentary in Tab 10, pages 9 and 16 are reflective of Centra's plan for serving Manitoba market requirements for the 2012/13 winter.

PUB/CENTRA II-189

Reference: CAC/Centra 29(b) & (e)

Please explain how Centra calculates the expected future storage costs when forecasting FRPGS WACOG and offering prices.

ANSWER:

The forecast impact of storage pertaining to the calculation of FRPGS WACOG and offering prices is determined in a similar manner to that for Centra's quarterly Primary Gas rate. For each year of each applicable forward FRPGS product term, the forecast financial impact of Primary Gas storage requirements to the load is determined assuming volumetric withdrawals under normal weather conditions. Winter withdrawals are priced at the forecast unit cost of Primary Gas storage inventories. The injections required to re-fill Primary Gas storage inventories in each of the summer injection seasons are also forecast under normal weather conditions. The same futures market strip as that utilized in the determination of forecast direct to the load supply prices at Empress is used in the calculation of forecast summer storage injection costs.

CAC/CENTRA II-45

Reference: **PUB/Centra I-6.**

Preamble: **Table 1 provides certain data points which are used to derive a forecast of Canadian 3 month T-bill rates for certain periods.**

Table 2 provides certain data points which are used to derive a forecast of Canadian 10 year + bond yield rates for certain periods.

CAC wishes to better understand the methodology employed in deriving these forecasts.

CAC observes that in Table 1 there are no 1Q 2014 values ascribed to CIBC, Laurentian, National Bank, Bank B, Scotia Bank, and would like to understand how the Fiscal 2013/14 T-bill rate forecast addressed the missing data points.

CAC also observes that in Table 2 there are no 1Q 2014 values ascribed to Desjardins, Laurentian, National Bank, and Scotia Bank, and there are no 1Q 2015 values ascribed to TD Bank and Conference Board, and would like to understand how the Fiscal 2013/14 and Fiscal 2014/15 10 year + Canada rate forecasts addressed the missing data points.

a) **Other than providing for the averaging of 10 year and 30 year bond yields to arrive at a 10 year + forecast rate, was the same methodology applied in converting the relevant data points found in the various forecasts supplied in**

attachment 1 used to derive the T-bill forecast in Table 1 and the Canada yield forecast in Table 2?

b) If the reply to "a" above is other than a full confirmation, please explain the reasons for the differences in methods applied.

c) Did the Infometrica contribution to the calculation of the average forecast T-bill rate for 2013/14 of 1.30% include, the values 1.80 for 2Q 2013, 1.80 for 3Q 2013, 1.80 for 4Q 2013 and 2.80 for 1Q 2014, and no other values.

d) If the reply to "c" above is other than a full confirmation, please explain the reasons for including or excluding other values and identify those values.

e) Did the Desjardins contribution to the calculation of the average forecast T-bill rate for 2013/14 of 1.30%, include the values 1.00 for 2Q 2013, 1.03 for 3Q 2013, 1.10 for 4Q 2013 and 1.55 for 1Q 2014, and no other values.

f) If the reply to "e" above is other than a full confirmation, please explain the reasons for including or excluding other values and identify those values.

g) Please explain the method of calculation of the average forecast T-bill rate for 2013/14 of 1.30%, for each of the "end period" forecasters for which there is no value indicated for 1Q 2014.

h) Did the Infometrica contribution to the calculation of the average forecast 10 year + rate for 2014/15 of 3.20% include, the values 3.60 for 2Q 2014, 3.60 for 3Q 2014, 3.60 for 4Q 2014 and 4.30 for 1Q 2015, and no other values.

i) If the reply to "h" above is other than a full confirmation, please explain the reasons for including or excluding other values and identify those values.

j) Did the TD Bank contribution to the calculation of the average forecast 10 year + rate for 2014/15 of 3.20% include, the values 2.99 for 2Q 2014, 3.11 for 3Q 2014, 3.23 for 4Q 2014 and, and no other values?

k) If the reply to "j" above is other than a full confirmation, please explain the reasons for including or excluding other values and identify those values.

l) Do the Fiscal 2013/14 and 2014/15 T-bill and 10 year + values, respectively 1.30, 2.10, 2.55 and 3.20, represent calculations rounded to the nearest 5 basis points, and if so, please provide the calculated values before rounding.

ANSWER:

Response to parts (a) and (b):

Please see the response to PUB/Centra II-141(b) for a description of the adjustments made to the interest rate forecasts.

Response to parts (c), (d), (e), (f), (h), (i), (j) and (k):

Centra confirms parts (c), (e), (h), and (j).

Response to part (g):

For 2013/14, the fiscal year forecast of the short and long term rates are derived from the average of all available quarterly forecasts for the period 2013 Q2 to 2014 Q1. Forecasters that do not provide a 2014 Q1 forecast still contribute to the calculation of the 2013/14 fiscal year rate by providing forecasts for Q2, Q3 and Q4 of 2013.

Response to part (l):

The fiscal year rates noted in Tables 1 and 2 of PUB/Centra I-6 were rounded to the nearest 5 basis points, as follows:

	Short Term		Long Term	
	Forecast	**Forecast (rounded to 5 basis points)**	**Forecast**	**Forecast (rounded to 5 basis points)**
2013/14	1.32	1.30	2.54	2.55
2014/15	2.10	2.10	3.22	3.20

CAC/CENTRA II-46

Reference: **PUB/Centra I-6.**

Preamble: **Table 1 provides certain data points which are used to derive a forecast of Canadian 3 month T-bill rates for certain periods.**

Table 2 provides certain data points which are used to derive a forecast of Canadian 10 year + bond yield rates for certain periods.

CAC wishes to better understand the methodology employed in deriving these forecasts.

CAC observes that certain data points available in the various forecasts in Attachment 1 have not been included in Tables 1 and 2, including the CIBC forecast values for 1Q 2014, and the Conference Board values for 10 year + Canada bond yields for 1Q 2015.

CAC estimates that using the CIBC period end forecast T-bill rate for March 2014 would have allowed the inclusion of the value 1.33 for 2014 Q1, in Table 1, where no value now appears, and would have been included in the calculation of the 2013/14 Fiscal year forecast T-bill rate.

CAC estimates that using the Conference Board data points for 10 year and long Canada rates for 1Q 2015, would have allowed the inclusion of the value 2.41 for 2015 Q1 in Table 2, where no value now appears, and would have been included in the calculation of the 2014/15 Fiscal year

forecast 10 year + rate. CAC estimates that the exclusion of this 2.41 value may have increased the 2014/15 forecast 10 year + rate by 3.4 basis points, which after giving effect to rounding could have changed that 2014/15 forecast value by 5 basis points.

CIBC	4Q 2013	1Q 2014	Average	Source
T-bill	**1.20**	**1.45**	**1.33**	**Attachment 1 Page 1 of 29**
Conf. Bd	**10 year**	**Cdn Long**	**Average**	
1Q 2015	**2.30**	**2.52**	**2.41**	**Page 27 of 29**

a) Please confirm the calculation of the 1.33 value for the CIBC 1Q 2014 data point, or provide the corrected value.

b) Please confirm the calculation of the 2.41 value for the Conference Board 1Q 2015 data point, or provide the corrected value.

c) Please provide an update to Table 2 including a revised value for the 2014/15 Fiscal 10 year + rate, incorporating the 2.41 or other corrected value for the missing Conference Board 1Q 2015 data point.

ANSWER:

Response to parts (a) - (c):

Please see the response to PUB/Centra II-141(a) for Table 2. As described in Footnote 1 of that response, the fiscal year interest rates as originally calculated in response to PUB/Centra I-6 remain unchanged.

CAC/CENTRA II-47

Reference: **PUB/Centra I-6.**

Preamble: **Table 1 provides certain data points which are used to derive a forecast of Canadian 3 month T-bill rates for certain periods.**

Table 2 provides certain data points which are used to derive a forecast of Canadian 10 year + bond yield rates for certain periods.

CAC wishes to better understand the methodology employed in deriving these forecasts.

CAC also observes that certain values included in Tables 1 and 2, for which it cannot identify the data points available in the various forecasts in Attachment 1 which would appear to be required support the calculation of those values, including the CIBC period end values for Q1 through Q4 in 2014 in Table 2, and the National Bank values for Q2 through Q4 in Tables 1 and 2.

CIBC	4Q 2013	1Q 2014	Average	Source
10 year	2.60	2.65	2.625	Attachment 1
30 year	3.10	3.10	3.10	Page 1 of 29
		Avg	2.8625	

National	1Q 2013	2Q 2013	3Q 2013	4Q 2013
T-bill	0.94	1.05	1.57 ? 0.95	1.67
10 Year	1.65	2.10	?	2.40
30 Year	2.20	2.58	?	2.86

a) Please confirm that the average of the National Bank 1Q 2013 data point of 0.94, and the 2Q 2013 data point of 1.05, in each case for 3 month T-bills found on page 12 of 29 of Attachment 1 to PUB/Centra 1-6 would result in a 2Q 2013 period average value of 1.00 rather than the 1.31 value found for 2Q 2013 in Table 1, or if unable to confirm explain the calculation of the 1.31 value for that time period.

b) Please confirm that for the National Bank 3Q 2013 period average T-bill value to be 1.31, based on a 1.05 opening data point, the National Bank 3Q 2013 end period data point would need to be 1.57, or if unable to confirm please provide the alternative value and identify its source in Attachment 1.

c) Please confirm that for the National Bank 4Q 2013 period average T-bill value to be 1.31, based on a 1.67 end period data point, the National Bank 3Q 2013 end period data point would need to be 0.95, or if unable to confirm please provide the alternative value and identify its source in Attachment 1.

d) Please confirm that the average of the National Bank 1Q 2013 10 year and 30 year data points of 1.65 and 2.20, and the 2Q 2013 data points of 2.10 and 2.58, found on page 12 of 29 of Attachment 1 to PUB/Centra 1-6 would result in a 2Q 2013 period average 10 year + value of 2.13 rather than the 2.28 value found for 2Q 2013 in Table 2, or if unable to confirm explain the calculation of the 2.28 value for that time period.

e) Please provide the National Bank 3Q 2013 end period values for each of the 10 year and 30 year Canada rates which based on the 1Q and 4Q 2013 forecast values mathematically result in the average values of 2.28 for each of the 3Q and 4Q 2013 data points presented in table 2, or provide the methodology and supporting data points to arrive at the value 2.28 for each of the 2Q, 3Q and 4Q 2013 data points..

f) Please confirm that the correct value for the CIBC 1Q 2014 data point is 2.86, or provide the CIBC forecast data points that gave rise to the value 2.75.

<u>ANSWER</u>:

Response to parts (a) - (f):

As National Bank did not provide a 2013 Q3 end period data point, the Corporation calculated the average of the 2013 Q1 and 2013 Q4 end period data to derive the 2013 Q2, Q3 and Q4 average period data points. For example, as shown in the following chart, for the National Bank T-Bill rate, the adjusted quarterly average forecast for 2013 Q1 was 0.96 (the average of 0.98 and 0.94) and the derived average for 2013 Q2, Q3 and Q4 was 1.31 (the average of 0.94 and 1.67).

	2012 Q4	2013 Q1	2013 Q2	2013 Q3	2013 Q4
T-Bill End Period	0.98	0.94	1.05		1.67
T-Bill Average Period	0.98	0.96	1.31	1.31	1.31

Utilizing the same approach, the Canadian long term interest rate (which averages the 10 year and 30 year long bond data points) from National Bank was as follows:

	2012Q4	2013Q1	2013Q2	2013Q3	2013Q4
10 Year Long Bond End Period	1.76	1.65	2.10		2.40
10 Year Long Bond Average Period	1.77	1.71	2.03	2.03	2.03

	2012Q4	2013Q1	2013Q2	2013Q3	2013Q4
30 Year Long Bond End Period	2.31	2.20	2.58		2.86
30 Year Long Bond Average Period	2.31	2.26	2.53	2.53	2.53

	2012Q4	2013Q1	2013Q2	2013Q3	2013Q4
Average of 10 and 30 Year Long Bond	2.04	1.98	2.28	2.28	2.28

An alternative approach would be to interpolate between the Q2 and Q4 end points to derive the 2013 Q3 end point, and then calculate average period data of all known or derived end points. Under this approach, for the Canadian long term interest rate, the adjusted quarterly forecast from National Bank would have been as follows:

	2012Q4	2013Q1	2013Q2	2013Q3	2013Q4
10 Year Long Bond End Period	1.76	1.65	2.10	2.25	2.40
10 Year Long Bond Average Period	1.77	1.71	1.88	2.18	2.33

	2012Q4	2013Q1	2013Q2	2013Q3	2013Q4
30 Year Long Bond End Period	2.31	2.20	2.58	2.72	2.86
30 Year Long Bond Average Period	2.31	2.26	2.39	2.65	2.79

	2012Q4	2013Q1	2013Q2	2013Q3	2013Q4
Average of 10 and 30 Year Long Bond	2.04	1.98	2.13	2.41	2.56

When combining the National Bank forecast with the other forecast sources and rounding to the nearest five basis points, Centra can confirm that utilizing the alternative method would have resulted in the same forecasted short and long term interest rates for the 2012/13 and 2013/14 Test Years.

National Bank is considered by the Corporation to be an appropriate and credible forecasting source, and as noted in Footnote 9 of PUB/Centra II-141(b), the impact of any computational adjustments such as those for National Bank is normally immaterial to the Economic Outlook.

As noted in the response to PUB/Centra II-141(a), Centra also confirms that the 2014 Q1 data point for CIBC is 2.86.

CAC/CENTRA II-48

Reference: **PUB/Centra I-6.**

Preamble: **Table 1 provides certain data points which are used to derive a forecast of Canadian 3 month T-bill rates for certain periods.**

Table 2 provides certain data points which are used to derive a forecast of Canadian 10 year + bond yield rates for certain periods.

CAC observes that the preponderance of data points in Attachment 1 sources are quarterly data points, but certain annual data points available in the various forecasts in Attachment 1 have been included in Tables 1 and 2, including some identified as being sourced from Desjardins, CIBC and Infometrica.

CAC also observes that while quarter over quarter forecast interest rate changes are generally modest, the CIBC 4Q 2014 to 1Q 2015 ascribed change is 73 basis points, the HIS Global 4Q 2014 to 1Q 2015 ascribed change is 80 basis points and the 4Q 2014 to 1Q 2015 change is 70 basis points.

CAC wishes to better understand the methodology employed in deriving these forecasts, including the manner in which annual averages data points are ascribed to the first quarter of a year and its effect on the quality of the forecast.

a) Please explain the efficacy of using 3/4s of the annual average of one calendar year's forecast average interest rate, and ¼ of the annual average of the following calendar year's interest rate as a proxy for the interest rate of an offset fiscal year in market conditions where interest rates are forecast to be rising over time.

b) Please explain the efficacy of using 3/4s of the annual average of one calendar year's forecast average interest rate, and ¼ of the annual average of the following calendar year's interest rate as a proxy for the interest rate of an offset fiscal year in market conditions where interest rates are forecast to be falling over time.

c) In as much as Centra needs to forecast fiscal periods that are not coincident with the calendar year, why has Centra not preferred data sources that provide quarterly data points and excluded sources that supply annual data points requiring adjustment in its forecast methodology?

ANSWER:

Response to parts (a) - (c):

In response to changing market conditions, either rising and falling over time, the Corporation follows a regular review process as described in response to PUB/Centra II-141(b).

Annual calendar year information is adjusted to fiscal year information on a proportionate basis. For a discussion regarding the efficacy and integration of annual (12 month) and quarterly (3 month) data, please see the response to PUB/Centra II-141(b).

CAC/CENTRA II-49

Reference: **PUB/Centra I-6.**

Preamble: **Table 1 provides certain data points which are used to derive a forecast of Canadian 3 month T-bill rates for certain periods.**

Table 2 provides certain data points which are used to derive a forecast of Canadian 10 year + bond yield rates for certain periods.

CAC observes that the identities and input data for Bank A and Bank B are suppressed.

CAC also observes that the visible data points for 2Q and 3Q 2012 in Table 1 and Table 2 are equal in each column, in spite of the fact that some that some of the forecasts date from September 1, 11, 17, 18, 19 or 25, 2012, dates at which the average value would not have been known.

Based on data in Attachment 1, CAC estimates that the forecast values for 3Q 2012 in Table 2 would have been 2.14 for Desjardins, and, 2.04 for Laurentian, based on the respective September 1 and September 17th forecasts.

		2Q 2012	3Q 2012		2Q 2012	3Q 2012
Desjardins	**10 yr**	**1.74%**	**1.95%**	**Laurentian**	**1.74%**	**1.75%**
Desjardins	**30 yr**	**2.33%**	**2.55%**	**Laurentian**	**2.33%**	**2.35%**
			2.14%			**2.04%**

CAC wishes to better understand the methodology employed in deriving these forecasts, including when the methodology requires that actual data is substituted for forecast data points.

a) **Please advise whether the data in the columns for 2Q and 3Q 2012 in Table 1 and Table 2 is actual data, or if unable to confirm provide the source and description.**

b) **If the data in the columns for 2Q and 3Q 2012 in Table 1 and Table 2 is actual data, and therefore not proprietary data of any bank or commercial forecaster, why are the values for Bank A and Bank B suppressed?**

ANSWER:

Response to parts (a) and (b):

The data for 2012 Q2 and Q3 as shown in Tables 1 and 2 is actual data. For a discussion of Bank A and Bank B, please see the response to PUB/Centra II-141(a).

CAC/CENTRA II-50

Reference: **CAC - CENTRA II-50**

Preamble: **Table 1 provides certain data points which are used to derive a forecast of Canadian 3 month T-bill rates for certain periods.**

Table 2 provides certain data points which are used to derive a forecast of Canadian 10 year + bond yield rates for certain periods.

CAC observes that the identities and input data for Bank A and Bank B are suppressed.

CAC also observes that Bank A is identified as forecasting period average data and is aware that BMO provides forecasts of certain interest rates on a period average basis.

CAC observes that in the 2009/10 GRA, in CAC/MSOS/Centra 1-4, Centra declined to provide copies of the forecasts relied upon at that time, and in the May 1, 2009 reply to PUB/Centra 2-198, provided the names of forecasters included but chose not to link the forecaster's name to the values they had forecast. It was only in the June 1, 2009 revision of PUB/Centra 2-198 that Centra linked the names of the forecasters to the date of the forecast and forecast values.

CAC is aware that in the first week of October 2012 BMO published certain forecast T-bill and Canada bond rates up to and including 4Q

2013, forecasting among other things 4Q average T-bill rates of 1.26% and 4Q 10 year Canada bond rates of 2.11%.

a) Is Bank A, the Bank of Montreal, BMO Capital Markets, BMO Nesbitt Burns, or one of their related companies?

b) Please confirm that financial forecasts, of T-bill and Canada bond rates, from BMO related companies are readily available from sites including: http://www.bmonesbittburns.com/economics/rates/20130404/rates.pdf

c) To the extent that any portion of the forecast rates of Bank A and Bank B were in the public domain or readily available on the internet, please update Tables 1 and 2 of PUB/Centra I-6 to incorporate the data in the public domain or readily available, and provide the forecast document.

ANSWER:

Response to parts (a) - (c):

For a discussion of Bank A and Bank B, please see Centra's response to PUB/Centra II-141(a).

CAC/CENTRA II-51

Reference: **PUB/Centra I-6, PUB/Centra 2-198 June 1, 2009 Revision, in the 2009/10 Centra GRA.**

Manitoba Hydro transcript of its recent GRA, beginning at page 1103, where Mr. Schulz refers to an "internal debate on this, and as recently as just in the last number of weeks" related to "how best to assess the accuracy of these forecasters".

Tab 4 page 2 of 7 which discusses an update of the spring Economic Outlook and a review of the IFF in the spring and summer forecasts resulting in an update "in the fall of 2012".

Preamble: **Tables 1 and 2 in PUB/Centra I-6 provide a list of 11 forecasters, including Bank A, Bank B, Desjardins and Laurentian and data derived from their forecasts, which were thought worthy to have data from their forecasts used as the inputs into the Centra interest rate forecast, but were not included in the list of worthy forecasters in the PUB/Centra 2-198 June 1, 2009 Revision.**

PUB/Centra 2-198 June 1, 2009 Revision, in the 2009/10 Centra GRA provides a list of 13 forecasters, including BMO Nesbitt and Spatial Economics who were at that time thought worthy to have data from their forecasts used as the inputs into the Centra interest rate forecast, and are no longer listed in Tables 1 and 2 in PUB/Centra I-6.

CAC wishes to better understand the timing, process and reasons for the inclusion of Bank A, Bank B, Desjardins and Laurentian and the removal of, BMO Nesbitt and Spatial Economics, from list of forecasters thought worthy to have data from their forecasts used as the inputs into the Centra interest rate forecast.

a) **For each of Bank A, Bank B, Desjardins and Laurentian, please identify the date at which their data was first added to the Economic Outlook and interest rate forecasting sample group?**

b) **At the time each of Bank A, Bank B, Desjardins and Laurentian were added to the Economic Outlook and interest rate forecasting sample group, what other forecasters, if any, were considered for inclusion, but were not included?**

c) **Please identify the reasons for the selection of each of Bank A, Bank B, Desjardins and Laurentian, having particular regard to the frequency of their forecasts, the reliability or historic accuracy of their forecasts, the length of their forecast periods, the number of consecutive quarterly periods for which they provide estimates, and any other material factors.**

d) **For each of BMO Nesbitt and Spatial Economics, please identify the date at which their data was first removed from the Economic Outlook and interest rate forecasting sample group?**

e) **At the time each of BMO Nesbitt and Spatial Economics were removed from the Economic Outlook and interest rate forecasting sample group, what other forecasters, if any, were considered for removal, but were not removed?**

f) **Please identify the reasons for the removal of each of BMO Nesbitt and Spatial Economics having particular regard to the frequency of their forecasts, the**

reliability or historic accuracy of their forecasts, the length of their forecast periods, the number of consecutive quarterly periods for which they provide estimates, and any other material factors.

g) **Please identify whether the "internal debate" referenced by Mr. Schulz preceded or was subsequent to the dates at which each of Bank A, Bank B, Desjardins and Laurentian were included, and each of BMO Nesbitt and Spatial Economics were removed from the lists of worthy forecasters.**

h) **Between June 1, 2009 and the September and October 2012 forecast revisions, were there any forecasters added that were subsequently removed?**

i) **In observing that there were 13 worthy forecasters at the time of PUB/Centra 2-198 June 1, 2009 Revision, and there were only 11 worthy forecasters at the time of September and October 2012 forecast revision, CAC inquires as to whether Centra has formed or revised its view of the optimum number of forecasters to be included in the sample to obtain a robust forecast?**

j) **In observing that the presentation of the interest forecast data by the National Bank frequently is discontinuous, in that one of the quarterly data points is not provided [3Q 2013 is not reported in the forecast on page 12 of 29 of Attachment 1 to PUB/Centra I-6], and that discontinuity appears to require adjustments to the data [as seen in Tables 1 and 2 to PUB/Centra/ I-6], CAC enquires, what special features or forecast accuracy does the National Bank forecast possesses to merit its continued inclusion in the sample of source providers to overcome the discontinuity of data points, and through a period where other sources have been added and dropped?**

<u>ANSWER</u>:

Response to parts (a) - (j):

For a discussion of Bank A and Bank B, see Centra's response to PUB/Centra II-141(a).

For a discussion pertaining to the utilized forecasters, please see Centra's response to PUB/Centra II-141(b).

For a discussion of the National Bank forecast, please see Centra's response to CAC/Centra II-47.

CAC/CENTRA II-52

Reference: **PUB/Centra I-42**

Preamble: **The table in PUB/Centra I-42 provides certain data points showing the forecast, actual, and variance between forecast and actual interest costs for certain periods.**

CAC observes that in each of the 4 years provided, forecast interest costs exceed actual costs. CAC calculates that the forecast interest costs exceeded actual costs in one year by approximately 23%, and in aggregate forecast interest costs exceeded actual costs by approximately $10 million.

PUB Central I-42	2008/09	2009/10	2010/11	2011/12	Total
Interest on LT	13,753	14,305	14,142	14,390	56,590
Interest on ST	2,758	342	131	102	3,333
	16,511	14,647	14,273	14,492	59,923
Forecast					
Interest on LT	13,760	14,987	15,342	15,342	59,431
Interest on ST	4,384	912	1,719	3,530	10,545
	18,144	15,899	17,061	18,872	69,976
Variance					
Interest on LT	- 7	- 682	-1,200	- 952	- 2,841
Interest on ST	-1,626	- 570	-1,588	-3,428	- 7,212
	-1,633	- 1,252	-2,788	-4,380	- 10,053
Variance as a % of actual					
Interest on LT	0%	5%	8%	6%	5%
Interest on ST	37%	63%	92%	97%	68%
Total	9%	8%	16%	23%	14%

CAC wishes to better understand whether the excess forecast interest costs are arising as a result of the forecast methodology, changes in the capital spending or debt levels.

a) **In light of the fact that in each of the past 4 years forecast interest costs have exceeded actual interest cost by at least 8% and as much as 23% in one year, can Centra advise as to the level of excess or deficit in forecast accuracy which would warrant a change in the forecast methodology or sample of forecasters selected?**

b) **For each of the 4 annual forecasts of interest expense on long term debt, please quantify, the cause of the variance between actual and forecast, the effect, if any, of swaps, extensions or adjustments to the terms of existing issues, changes in estimated date of issue, principal amount, or interest basis [fixed or floating] of forecast issues, variance of market rate from the forecast rate, or deferral of issues related to changes in capital requirements from those forecast.**

c) **For each of the 4 annual forecasts of interest expense on short term debt, please quantify, the cause of the variance between actual and forecast, the effect, if any, of swaps, extensions or adjustments to the terms of existing issues, changes in estimated date of issue, principal amount, or interest basis [fixed or floating] of forecast issues, variance of market rate from the forecast rate, operation of any "true-up", or deferral of issues related to changes in capital requirements from those forecast.**

d) **Please advise the last financial period in which forecast interest costs were exceeded by actual interest costs.**

ANSWER:

Response to parts (a), (b), (c) and (d):

Centra disagrees with the premise outlined in the preamble to this Information Request that variations between forecast and actual interest costs as shown in Centra's response to PUB/Centra I-42(b), arise as a result of the forecast methodology, changes in the capital spending or debt levels.

During the 2009/10 & 2010/11 Centra GRA, the global economy was in the midst of a financial crisis that led to a significant reduction in actual interest rates. Since that time, actual interest rates continue to decrease as the anticipated macro-economic recovery did not occur. The differences between forecast and actual interest costs are primarily associated with these significant financial market changes.

CAC/CENTRA II-53

Reference: **PUB/Centra I-42 and Schedules 5.8.2, 5.8.3 and 5.8.4 from the Centra 2009/10 GRA**

Preamble: **The table in PUB/Centra I-42 provides certain data points showing the forecast interest costs for certain periods.**

CAC observes that the forecast interest cost for long term debt for 2008/09 in Schedules 5.8.3, approximately agrees to that found in PUB/Centra I-42, but CAC calculates the values for the 2010/11 test year in schedule 5.8.4 from the Centra 2009/10 GRA, do not agree with the forecast found in PUB/Centra I-42.

CAC observes that Schedule 5.8.4 appears to forecast approximately $16,029,000 in long term debt interest resulting in unexplained variance is approximately $687,000 in 2010/11.

CAC wishes to better understand these differences in calculation.

a) **Please provide a reconciliation of these variances between the information in Schedules 5.8.3 and 5.8.4 from the Centra 2009/10 GRA, using a format similar to that found in lines 24 to 36 of Schedule 5.8.4.**

b) **Please identify the other factors, including change of issue size, coupon or yield to maturity, which gave rise to the variances in new or extended issues.**

c) Please confirm that Schedules 5.8.3 and 5.8.4 from the Centra 2009/10 GRA reported a forecast short term rate of 5.05% for 2009/10, and 5.60% for 2010/11, and provide the forecast short term rate for 2011/12 forecast in CGM08-01.

ANSWER:

Response to (a) & (b):

Centra observes that the schedules referenced in this Information Request were originally filed on January 20, 2009 as part of the 2009/10 GRA, as opposed to the updated Schedules filed on May 29, 2009 which were examined in detail at the 2009/10 GRA hearing.

Attached to this response, please find updated Schedules 5.8.3 and 5.8.4, together with Schedule 4.12.0 which summarizes total Finance Expense, filed on May 29, 2009, which reconciles to the information provided in response to Information Request PUB/Centra I-42(b) in this GRA.

Response to (c):

The initial and updated forecasted short term interest rates (inclusive of the 1% Provincial Guarantee Fee) were as follows:

Forecast Short Term Interest Rate

	2009/10	2010/11	2011/12
CGM08 Initial Application January 20, 2009	5.05%	5.60%	5.60%
CGM08 Updated Application May 29, 2009	1.90%	3.00%	4.90%

CENTRA GAS MANITOBA INC. **Schedule 5.8.3**
13 Month Average Debt Financing

($000'S)
2009/10 Test Year **May 29, '09**

Principal Balances Debt Code	Principal at Start of Year	Principal at End of Year	30 Apr-09	31 May-09	30 Jun-09	31 Jul-09	31 Aug-09	30 Sep-09	31 Oct-09	30 Nov-09	31 Dec-09	31 Jan-10	28 Feb-10	31 Mar-10	365 Monthly Average
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
CG 1	62,671	62,671	1,880,118	1,942,789	1,880,118	1,942,789	1,942,789	1,880,118	1,942,789	1,880,118	1,942,789	1,942,789	1,754,777	1,942,789	62,671
CG 4	18,077	0	542,316	560,393	542,316	560,393	560,393	542,316	560,393	542,316	560,393	560,393	506,162	542,316	18,028
CG 5 (EM 3 & 4)	75,000	0	2,250,000	2,325,000	2,250,000	2,325,000	2,325,000	2,250,000	2,325,000	2,250,000	2,325,000	2,325,000	1,575,000	0	67,192
CG 7 - (Refinance CG 3)	50,000	50,000	1,500,000	1,550,000	1,500,000	1,550,000	1,550,000	1,500,000	1,550,000	1,500,000	1,550,000	1,550,000	1,400,000	1,550,000	50,000
CG 8 - (CG 6 Extension)	30,000	30,000	900,000	930,000	900,000	930,000	930,000	900,000	930,000	900,000	930,000	930,000	840,000	930,000	30,000
New Issue March 2009	30,000	30,000	900,000	930,000	900,000	930,000	930,000	900,000	930,000	900,000	930,000	930,000	840,000	930,000	30,000
New Issue March 2010	0	30,000	0	0	0	0	0	0	0	0	0	0	0	30,000	82
New Issue (Refinance CG 5)	0	75,000	0	0	0	0	0	0	0	0	0	0	525,000	2,325,000	7,808
New Issue (Refinance CG 4)	0	20,000	0	0	0	0	0	0	0	0	0	0	0	20,000	55
Balances at April 1 and March 31	265,748	297,671													
Monthly Debt Balances Weighted by Day			7,972,434	7,308,182	7,072,434	7,308,182	7,308,182	7,072,434	7,308,182	7,072,434	7,308,182	7,308,182	6,075,938	4,965,105	
Average Monthly Debt Balance			265,748	265,748	265,748	265,748	265,748	265,748	265,748	265,748	265,748	265,748	265,748	266,778	265,835

Financing Costs on Debt	Interest Expense Long Term	Short Term
CG 1	3,792	
CG 4	997	
CG 5 (EM 3 & 4)	4,212	
CG 7 - (Refinance CG 3)	2,253	
CG 8 - (CG 6 Extension)	1,890	
New Issue March 2009	1,470	
New Issue March 2010	0	
New Issue (Refinance CG 5)	371	
New Issue (Refinance CG 4)	3	
Provincial Guarantee Fee	2,657	
Sub-total of Debt Financing Cost	17,644	
Amortization of Redemption Premium	1,262	
Net Cost of Debt Financing	18,906	
Embedded Cost of Long Term and Short Term Debt	7.11%	1.90%

CENTRA GAS MANITOBA INC. **Schedule 5.8.4**
13 Month Average Debt Financing

($000'S)
2010/11 Test Year **May 29, '09**

Line	Principal Balances Debt Code	Principal at Start of Year [1]	Principal at End of Year [2]	30 Apr-10 [3]	31 May-10 [4]	30 Jun-10 [5]	31 Jul-10 [6]	31 Aug-10 [7]	30 Sep-10 [8]	31 Oct-10 [9]	30 Nov-10 [10]	31 Dec-10 [11]	31 Jan-11 [12]	28 Feb-11 [13]	31 Mar-11 [14]	365 Monthly Average [15]
6	CG 1	62,671	62,671	1,880,118	1,942,789	1,880,118	1,942,789	1,942,789	1,880,118	1,942,789	1,880,118	1,942,789	1,942,789	1,754,777	1,942,789	62,671
7	CG 7 - (Refinance CG 3)	50,000	50,000	1,500,000	1,550,000	1,500,000	1,550,000	1,550,000	1,500,000	1,550,000	1,500,000	1,550,000	1,550,000	1,400,000	1,550,000	50,000
8	CG 8 - (CG 6 Extension)	30,000	30,000	900,000	930,000	900,000	930,000	930,000	900,000	930,000	900,000	930,000	930,000	840,000	930,000	30,000
9	New Issue March 2009	30,000	30,000	900,000	930,000	900,000	930,000	930,000	900,000	930,000	900,000	930,000	930,000	840,000	930,000	30,000
10	New Issue March 2010	30,000	30,000	900,000	930,000	900,000	930,000	930,000	900,000	930,000	900,000	930,000	930,000	840,000	930,000	30,000
11	New Issue (Refinance CG 5)	75,000	75,000	2,250,000	2,325,000	2,250,000	2,325,000	2,325,000	2,250,000	2,325,000	2,250,000	2,325,000	2,325,000	2,100,000	2,325,000	75,000
12	New Issue (Refinance CG 4)	20,000	20,000	600,000	620,000	600,000	620,000	620,000	600,000	620,000	600,000	620,000	620,000	560,000	620,000	20,000
14	Balances at April 1 and March 31	297,671	297,671													
16	Monthly Debt Balances Weighted by Day			8,930,118	9,227,789	8,930,118	9,227,789	9,227,789	8,930,118	9,227,789	8,930,118	9,227,789	9,227,789	8,334,777	9,227,789	
18	Average Monthly Debt Balance			297,671	297,671	297,671	297,671	297,671	297,671	297,671	297,671	297,671	297,671	297,671	297,671	297,671

Line	Financing Costs on Debt	Interest Expense Long Term	Short Term
25	CG 1	3,792	
26	CG 7 - (Refinance CG 3)	2,253	
27	CG 8 - (CG 6 Extension)	1,890	
28	New Issue March 2009	1,470	
29	New Issue March 2010	1,425	
30	New Issue (Refinance CG 5)	3,563	
31	New Issue (Refinance CG 4)	950	
33	Provincial Guarantee Fee	2,977	
35	Sub-total of Debt Financing Cost	18,319	
37	Amortization of Redemption Premium	298	
39	Net Cost of Debt Financing	18,616	
41	Embedded Cost of Long Term and Short Term Debt	6.25%	3.00%

CENTRA GAS MANITOBA INC.
Finance Expense - 2006/07 to 2010/11

Schedule 4.12.0

($000'S)
May 29, '09

	2006/07 Actual	2007/08 Actual	2008/09 Forecast	2009/10 Test Year	2010/11 Test Year
	[1]	[2]	[3]	[4]	[5]
Interest on Long Term Debt/Advances	13,762	13,547	13,760	14,987	15,342
Provincial Guarantee Fee on Long Term Debt	2,476	2,403	2,380	2,657	2,977
Amortization of Debt Discounts	1,692	1,253	1,256	1,262	298
Interest on Short Term Debt	3,349	4,665	4,384	912	1,719
Provincial Guarantee Fee on Short Term Debt	603	815	902	628	656
Interest on Common Assets	2,138	2,244	2,562	2,677	2,839
Interest on Inventory	24	32	24	25	27
Interest Capitalized	(1,958)	(3,270)	(3,101)	(2,253)	(2,862)
Other	9	22	58	97	21
Total Financing Expenses	22,095	21,711	22,225	20,992	21,017

CAC/CENTRA II-54

Reference: **PUB/Centra I-42, CGM08-1, page 22 to 25 in the Tab 3 attachments from the Centra 2009/10 GRA, and section 4.7 in Tab 4 of the application from the Centra 2009/10 GRA**

Preamble: **Centra indicates in PUB/Centra I-42, Finance Expense of 2009/10 of 20,992 and in CGM08-1, page 22 to 25 in the Tab 3 attachments from the Centra 2009/10 GRA, an amount of $24 million, and finally 24,656 in section 4.7 of Tab 4.**

Centra indicates in PUB/Centra I-42, Finance Expense of 2010/11 of 21,017 and in CGM08-1, page 22 to 25 in the Tab 3 attachments from the Centra 2009/10 GRA, an amount of $26 million, and, finally 25,237 in section 4.7 of Tab 4.

Centra indicates in PUB/Centra I-42, Finance Expense of 2011/12 of 23,376 and in CGM08-1, page 22 to 25 in the Tab 3 attachments from the Centra 2009/10 GRA, an amount of $26 million.

CAC would like to better understand these apparent inconsistencies.

a) **Please reconcile the 2009/10 finance expense numbers of $20,992, $24 million and $24,656 identified above.**

b) **Please reconcile the 2010/11 finance expense numbers of $20,017, $26 million and $25,237 identified above.**

c) Please reconcile the 2011/12 finance expense numbers of $23,367, and $26 million identified above.

<u>ANSWER</u>:

Response to (a), (b) and (c):

The 2009/10 & 2010/11 Centra GRA was filed in January 2009, and included CGM08-1 (pages 22 to 25 in the Tab 3 attachments) and Section 4.7 in Tab 4. Any variations between these numbers for the respective fiscal years were due to the rounding of CGM08-1 for presentation purposes.

As noted in CAC/Centra II-53, PUB/Centra I-42 from the 2013/14 Centra GRA utilized information from the updated filing on May 29, 2009.[1]

[1] Please note that the amount referenced by CAC from PUB/Centra I-42 in for 2010/11 should read $21,017 rather than $20,017; and for 2011/12 should read $23,375 rather than $23,376 or $23,367.

CAC/CENTRA II-55

Reference: **PUB/Centra I-42 and Schedule 4.12.0 of the application from the Centra 2009/10 GRA**

Preamble: **Centra indicates in PUB/Centra I-42, interest on short term debt for 2009/10 of $912 and in Schedule 4.12.0 of the application from the Centra 2009/10 GRA, an amount of $4,470.**

Centra indicates in PUB/Centra I-42, interest on short term debt for 2010/11 of $1,719 and in Schedule 4.12.0 of the application from the Centra 2009/10 GRA, an amount of $5,079.

Centra indicates in PUB/Centra I-42, interest on short term debt for 2011/12 of $3,530 but in Schedule 4.12.0 of the application from the Centra 2009/10 GRA, does not provide a comparable amount.

CAC would like to better understand these apparent inconsistencies.

a) Please indicate the forecast amount of interest on short term debt for 2011/12 that would have been prepared on a consistent basis to the forecasts of $4,470 for 2009/10 and of $5,079 for 2010/11 found in Schedule 4.12.0 referenced above.

b) Please reconcile the forecast interest on short term debt, of $4,470 for 2009/10 and the forecast contained in PUB/Centra I-42, for 2009/10 of $912, indicating

the changes in the amount of debt outstanding and changes in interest rate assumptions.

c) For Please reconcile the forecast interest on short term debt, of $5,079 for 2010/11 and the forecast contained in PUB/Centra I-42, for 2010/11 of $1,719 indicating the changes in the amount of debt outstanding and changes in interest rate assumptions.

ANSWER:

Response to part (a):

The comparable amount would be $5,547 thousand.

Response to parts (b) and (c):

Please see Centra's response to CAC/Centra II-54.

CAC/CENTRA II-56

Reference: **CAC/Centra I-6 and Section 4.1 in Tab 4 of the application**

Preamble: **Centra indicates in Section 4.1 page 1 of 7, in Tab 4 of the application, that the most recent forecasts as of the end of Q1 of the 2012 calendar year were used in developing the Economic Outlook.**

Centra indicates in Section 4.1 page 2 of 7, in Tab 4 of the application, that the summer review is usually the last point in time to incorporate information into the IFF process, unless there is a "significant financial market event".

Centra indicates in Section 4.1 page 2 of 7, in Tab 4 of the application, that "this year, the continued falling forecasts of near term interest rates …were considered materially different from the spring and summer forecasts".

CAC would like to better understand these material changes, and the level of interest rate forecast change which renders the result "materially different" from the prior data so as to require an update.

a) **Please provide the equivalent tables to Table 1 and Table 2 provided in PUB/Centra I-6 for the spring forecasts.**

b) Please provide the equivalent tables to Table 1 and Table 2 provided in PUB/Centra I-6 for the summer forecasts, many of which were provided in reply to CAC/Centra I-6 (a).

c) Please indicate whether the "materially different" result was in either long term debt rate forecasts, short term debt rate forecasts, or both, and quantify the change either in percentage or basis point terms for both the short and long term forecast rate.

d) Please provide copies of the source forecasts utilized by the Corporation as part of the spring preparation or review of the Economic Outlook.

ANSWER:

Response to parts (a) - (d):

As described in the response to PUB/Centra II-141(b), the Corporation has an established methodology for reviewing its interest rate forecasts. The IFF draws upon the most currently available Economic Outlook. As IFF12, which is the basis for the 2013/14 Centra General Rate Application, was produced in late fall/ early winter, the fall interest rate forecast was utilized. The 2012 spring and summer interest rate forecasts did not form the basis of Centra's 2013/14 General Rate Application. The 2013 Economic Outlook will be considered for the purposes of assessing whether to update the Application.

CAC/CENTRA II-57

Reference: **PUB/Centra I-43 and CAC/Centra I-10**

Preamble: **Centra indicates in PUB/Centra I-43, $60 million of new fixed rate financing in 2012/13 and a further $30 million of new financing in 2013/14.**

Centra indicates in CAC/Centra I-10, that MH had indicated that as an improvement to its forecasting methodologies, it would commencing with IFF 10 forecast 20% of new debt issuance as floating rate debt. This matter was referenced in 8.1.0 of the January 17, 2012 Board Order 5/12.

CAC would like to better understand whether the Centra forecast reflects the undertaking to forecast 20% of $90 million of new debt at the floating rate debt rates.

a) **Does the interest expense forecast for Centra for this and future periods recognize that 20% of new debt will be forecast as floating rate debt issues?**

b) **If the interest expense forecast for Centra for this and future periods does not recognize that 20% of new debt will be forecast as floating rate debt issues, please adjust various schedules and the CGM to reflect that commitment.**

c) **If it is the position of Hydro that its commitment to forecast 20% of new debt issuance as floating rate debt, attracting lower rates than the long term fixed rate interest forecast, is applicable only at the Hydro level, please provide the**

term sheet reflecting the interest rate and other terms of most recent floating rate issue undertaken Hydro, and the reference rate at the date of issue and at a proximate date to its reply to this question.

ANSWER:

Response to parts (a) - (c):

As Centra's long term debt issuance occurs less frequently than Manitoba Hydro's, Centra forecasts floating rate long term debt issuance on a discrete basis in order to align Centra's floating debt rate percentage within the target range of Centra's total debt portfolio. For example, in the 2013/14 fiscal year, a $30 million long term debt issue is forecast and 50% of this long term debt issue is forecast to be floating rate debt. If only 20% of this long term debt issue were to be floating rate long term debt, then Centra's floating rate debt percentage may become underweighted.

As described in response to CAC/Centra I-16 (a), the effective interest rate method is utilized to assess floating long term debt yield rates for financial reporting purposes. At the time of debt issuance, as floating and fixed rate debt of the same term to maturity have the same effective interest rate, it is incorrect to infer that floating rate debt will attract lower interest rates than fixed rate debt over the life of the debt issue.

CAC/CENTRA II-58

Reference: **CAC/Centra I-10**

Decision No.128/09 at pages 61 and 62 of 139

Preamble: **In the September 16, 2009, Decision No.128/09 at page 61 of 139, the Board wrote "The revised methodology for rate setting purposes should include; … A process to retrospectively test the accuracy of forecasters to assess their inclusion in future forecasts".**

In CAC/Centra I-10, Centra replies that "the Corporation considered that Directive No. 9 had been settled" as the PUB did not "direct the Corporation to undertake retrospective testing of its forecasters" in order 5/12 in respect of the MH GRA 2010/11.

CAC observes that the word "retrospective" does not appear in the Order 5/12, nor did the Board discuss testing of forecasts in the Intervener Positions section 8.3.0 of the Finance Expenses of the Order. CAC also observes that the Board did not appear to expressly absolve Centra of its obligation to comply with Decision 128/09 in Order 5/12.

Manitoba Hydro transcript of its GRA appears to suggest that the question of retrospective testing remains open as a result of the discussion between Mr. Peters and Mr. Schulz:, beginning at page 1103, where Mr. Schulz refers to an "internal debate on this, and as recently

as just in the last number of weeks" related to "how best to assess the accuracy of these forecasters"; continuing at page 1104, he also observes "It's a difficult thing to undertake. For us, when we're looking at this, and <u>we're still deliberating seriously on this issue</u>, is to say since the recovery period that we're currently in <u>we don't have enough data points</u>"; and, later at page 1104-5, "we're working with our economic analysis folks where <u>we're still looking to see what would be the best path forward on this</u>, so it's something that we're certainly taking seriously but at <u>this point in time we haven't done</u> …" {Emphasis added]

a) **Does Centra now have enough data points to undertake retrospective testing of the forecasts of the forecasters it was using in 2009 or was using in September and October 2012?**

b) **Is there another Board order or decision which expressly supersedes or repeals the September 16, 2009, Decision No.128/09 at page 61 of 139, in which the Board required that "The revised methodology for rate setting purposes should include; … A process to retrospectively test the accuracy of forecasters to assess their inclusion in future forecasts"?.**

<u>ANSWER</u>:

Response to parts (a) - (b):

As stated in the transcript from January 7, 2011 the Corporation has been deliberating seriously on the topic of retrospective testing of interest rate forecasters. To that end, the

Corporation has had discussions with economists from within its pool of external forecasters, and has also performed a review of relevant academic literature.

Based on these deliberations and consultations, it remains the Corporation's view that forecaster modeling algorithms are evolving since the financial crisis and that sufficient time through a full business cycle has not transpired to appropriately test the accuracy of these algorithms. Further, retrospective testing, with the aim of pruning or weighting forecaster opinions could potentially weaken or bias the Corporation's viewpoints in terms of understanding the spectrum of possibilities and mitigating the risk. For a broader discussion of the topic of retrospective testing of interest rate forecasters, please see the response to PUB/Centra II-141 (b).

Subsequent to Order 128/09, the topic of retrospective testing of interest rate forecasters was heavily canvassed at the 2010/11 & 2011/12 Electric GRA. Concurrently, as part of Centra's 2011/12 Cost of Gas proceeding, Centra filed its position on this topic in response to PUB/Centra 50 (b). In the PUB Orders arising out of these proceedings (Orders 5/12 and 65/11 respectively), the PUB did not recommend or redirect the Corporation to undertake retrospective testing of its interest rate forecasters.

CAC/CENTRA II-59

Reference: Decision No.128/09 at pages 62 and 63 of 139

Preamble: CAC observes that this hearing commenced with the filing of the Application on or about January 25, 2013.

In Decision No.128/09 at pages 62 and 63 of 139, the Board wrote "The Board will also expect Centra to propose a methodology to be used for rate setting purposes to update the interest rate forecast during the hearing process. The Board understands that an update is already required for the cost of gas, and that an updated interest rate forecast should also be provided. Centra may choose to update its interest rate forecast coincident with its cost of gas update". [Emphasis added]

CAC also observes that the dates of many of the forecasts referenced in PUB/Centra I-6 are now over 6 months old and have been superseded with new forecasts.

a) Will Centra choose to update its interest rate forecast coincident with its cost of gas update or later "during the hearing process" of this hearing?

b) If not, why not?

c) If the reason for not providing an update "during the hearing process" is that the changes in the forecast long and short term rates are not sufficiently material to warrant that transparency, please compare the change from spring,

to summer and then to fall 2012, which was judged to be sufficiently material to warrant such an update to the interest rate forecast.

<u>ANSWER</u>:

Response to parts (a) - (c):

Centra will file the 2013 Spring Economic Outlook when it is finalized, and will assess whether to revise the Application at that time.

CAC/CENTRA II-60

Reference: **Response to PUB-Centra I/94(a)**

Preamble: **The referenced IR response indicates that Centra will provide a high-level update on the National Energy Board's RH-003-2011 Decision in the second round Information Request process.**

a) **As part of Centra's high-level update, please discuss and describe the nature and extent of any changes to Centra's Mainline transportation and gas purchasing strategies that Centra considers may be necessary or desirable in light of the NEB's RH-003-2011 Decision, having regard in particular to (i) the elimination of the FT-RAM mechanism and (ii) the NEB's decision to allow TransCanada to set the bid floors for the Mainline IT and STFT services at any level it chooses above the equivalent FT tolls.**

ANSWER:

Please see Centra's response to PUB/Centra II-178 for a high level update on the NEB's RH-003-2011 Decision. On May 1, 2013 TransCanada made a Compliance Filing which included an Application to Review and Vary portions of the NEB decision.

Centra along with other shippers awaits confirmation of tolls for all paths and services; and bid floors for IT and STFT services. Once this information becomes available, Centra will evaluate its options using this information to inform its transportation contracting and gas supply purchase decisions going forward.

CAC/CENTRA II-60

Reference: **Response to PUB-Centra I/94(a)**

Preamble: **The referenced IR response indicates that Centra will provide a high-level update on the National Energy Board's RH-003-2011 Decision in the second round Information Request process.**

b) **Does Centra intend to revise its non-Primary Gas cost forecasts in this proceeding to reflect (i) the reduced FT tolls that were prescribed by the NEB in the RH-003-2011 Decision and (ii) the impact of any changes to Centra's Mainline transportation portfolio (e.g. increased levels of Empress-to-MDA FT service) that Centra expects to implement as a result of the Decision, and as discussed in the response to (a)? Explain why or why not?**

ANSWER:

Centra does not intend to revise its non-Primary Gas cost forecasts in this proceeding to reflect any prospective changes to TCPL tolls and/or make any changes to Centra's Mainline transportation portfolio due to the uncertainty as described in Centra's response to CAC/Centra II-60(a).

CAC/CENTRA II-61

Reference: Order 128/09 at 34

Preamble: The Board ordered the Company to prepare a demographic study that includes "The neighbourhoods where lower income consumers reside in order that targeted mailings and other marketing activities can be directed where they will be best received".

Please provide all the Company's documentation in response to this order.

ANSWER:

As noted in CAC/Centra I-20(a), Centra filed the 2009 Residential Energy Use Survey Report – Low Income Cut-off (LICO) in response to Directive 7 of Order 128/09 on May 28, 2010, and a revised report on August 31, 2010.

The 2009 Manitoba Hydro Residential Customer Survey provided global demographic data for Manitoba, and was broken down into both LICO125 and non- LICO125 dwellings. The study also provided data on the number of lower income consumers; the numbers of standard, mid-efficiency, and high efficiency furnaces and boilers; the type of housing (single, multi-unit, townhouse, mobile, owned, rented); and consumption data associated with low income dwellings. The study was never intended to provide data at a neighbourhood level that would provide statistically valid results to enable targeted marketing to lower income neighbourhoods. It was intended to provide global characteristics of the lower income market.

The City of Winnipeg, in partnership with local community organizations, other levels of government and the Community Social Data Strategy group, matched 2006 Statistics Canada Census Data to Winnipeg neighbourhood geographic areas. Instead of incorporating neighbourhood demographics into the 2009 Residential Energy Use Survey, Centra used existing Census data at the neighbourhood demographic level to pursue targeted mailings and other marketing activities. Targeted neighbourhoods for the Lower Income Energy Efficiency Program were identified by evaluating the data with criteria such as household income, ownership and age of dwellings.

CAC/CENTRA II-62

Reference: CAC / Centra I-20(b) and (ii)

a) Please provide all the Company's documentation regarding LICO-100 and LICO-125 gas customer insulation ratings and basement insulation levels.

ANSWER:

The 2009 Residential Energy Use Survey - Low Income Cut-off (LICO) Sector contains information on LICO and LICO 125 natural gas serviced customers' insulation ratings and basement insulation levels. The survey results were provided in Centra's response to CAC/Centra I-20(a) at page 16 of the filing. The questions pertaining to customers' insulation ratings and basement insulation levels are shown starting at page 56.

CAC/CENTRA II-62

Reference: CAC / Centra I-20(b) and (ii)

b) Please reconcile the number and percentage of LICO-125 customers who are renters as shown in (i) the response to CAC/Centra I-20(b) and (ii) Table 4.2 of the 2009 Residential Energy Use Survey Report (p. 118).

ANSWER:

The difference between the two responses for the number of LICO-125 renters, 4,572 as stated in Centra's response to CAC/Centra I-20(b) and 5,171 as stated in Table 4.2 of the 2009 Residential Energy Use Survey – Low Income Cut-off Sector report, was primarily due to the adjustment in weightings for the overall Residential Energy Use Survey findings that was performed subsequent to the LICO Sector report as described in the response to CAC/Centra I-20(a). Each survey response represents a number of customers within the overall population of customers, referred to as the weighting for the response. Weightings are calculated using the ratio between the population and the number of responses for a particular group (or strata). The population is divided into strata of similar types of customers. This gives surveys more accuracy and makes them more representative of the population.

A natural gas customer weighting criteria was introduced to match the final survey results to actual number of gas customers. Adding another weighting variable creates many small strata with few surveys. Less important weighting criteria were combined to ensure an adequate number of survey responses in each stratum resulting in an adjustment to the overall number of natural gas heated LICO-125 tenants.

CAC/CENTRA II-62

Reference: CAC / Centra I-20(b) and (ii)

c) Describe (a) the method by which the existence of fair or poor insulation is determined, and (b) how the method has been proven to accurately reflect actual conditions.

ANSWER:

(a) To determine the existence of fair or poor insulation levels customers were surveyed via the 2009 Residential Energy Use Survey - Low Income Cut-off (LICO) Sector. Customers were asked “What best describes the overall level of INSULATION in your residence? (excluding Basement)” and were instructed to mark an “x” in the box(es) beside the appropriate answer. The options provided were Excellent, Very Good, Average, Fair or Poor.

(b) It was determined that the above methodology was the best approach to estimate insulation conditions based upon past survey responses. In the 2003 Residential Energy Use Survey, customers were asked to indicate the insulation R-values present in their dwellings. The results could not be used to accurately estimate actual R-values in the market as “Do Not Know” was indicated 55.0% of the time for attic insulation and 33.6% of the time for basement insulation. Incorporating a customer’s qualitative assessment in the 2009 survey was deemed to be the best method to limit non-respondent error and more accurately approximate the insulation levels in the residential dwelling market.

CAC/CENTRA II-63

Reference: CAC / Centra I-20(e)(i) and (ii)

a) Please provide the full and complete rationale for excluding rental apartments from the program.

ANSWER:

Centra works with property managers to assist them in improving the overall energy efficiency of their facilities through its variety of Commercial Power Smart Programs, including such measures as boilers, ventilation and CO2 sensors, insulation and windows, and energy efficiency showerheads.

Opportunities for individual in-suite savings from insulation and furnaces are limited in rental apartments. It is not feasible to upgrade the insulation of individual suites. In addition, the majority of natural gas heated apartment blocks do not have individual suite based heating systems; instead most will have a central heating and cooling system.

CAC/CENTRA II-63

Reference: CAC / Centra I-20(e)(i) and (ii)

b) Please provide the full and complete rationale for not requiring a landlord contribution with respect to improvements financed by billings to tenants under the Pay As You Save program.

ANSWER:

The Pay As You Save Program (PAYS) operates under the principle that improvements are financed by the party that benefits from the bill reductions arising from the energy savings associated with the improvement. The Program addresses the reluctance of landlords to undertake energy efficiency upgrades that provide no monetary benefit to the landlord (e.g. where bill savings accrue to the tenant). In situations where the cost of the upgrade exceeds the amount eligible for financing under the PAYS Program, the landlord has the option to provide funds to cover the cost difference.

Landlords with qualifying low income tenants may be eligible to participate in an enhanced offering outlined in Centra's response to CAC/Centra II-65.

CAC/CENTRA II-63

Reference: CAC / Centra I-20(e)(i) and (ii)

c) With respect to insulation, state whether Landlord participation in the Home Insulation (rebate) Program is required and, if not, provide the full and complete rationale why not.

ANSWER:

Applicants for the Home Insulation Program (HIP) must be the owner(s) of the home, who may be a landlord or the resident. Tenants require written permission from their landlord if they wish to utilize the Home Insulation Program to upgrade their rented home.

As with all Power Smart Programs, participation in HIP is voluntary.

CAC/CENTRA II-63

Reference: CAC / Centra I-20(e)(i) and (ii)

d) Provide all the program details of the Home Insulation Program for landlords, including the amount of the rebate and the amount of the average cost of the measure.

ANSWER:

Landlords participate in the Power Smart Home Insulation Program in the same manner as other homeowners and receive the same rebates to cover insulation material costs, as outlined in Centra's response to CAC/Centra I-20(e) (i & ii). Rebate amounts vary by project type (e.g. attic, wall, foundation) and the additional R-value of insulation being installed.

The average rebate received to date by landlords participating in the Home Insulation Program is $764 dollars. The average material cost of these projects is $1240 while the average total cost of these projects is $1819.

CAC/CENTRA II-63

Reference: CAC / Centra I-20(e)(i) and (ii)

e) Provide all the program details of the "Other Initiatives" for landlords of lower income households and the participation therein by landlords of lower income households.

ANSWER:

Program details of the "Other Initiatives" for landlords of lower income households can be found in Appendix 7.1 - 2011 Power Smart Plan, Section 1.3 Commercial Portfolio, of this General Rate Application.

Tenant household income for multi-unit residential buildings is not collected as this is not a condition of program eligibility.

CAC/CENTRA II-63

Reference: CAC / Centra I-20(e)(i) and (ii)

f) Provide all the program details of the Neighbourhood Power Smart Project for landlords of lower income households and the participation therein by landlords of lower income households.

ANSWER:

The Neighbourhood Power Smart Project assists landlords of lower income households to improve energy efficiency levels through the use of PAYS financing and/or the Lower Income Program. Under the Neighbourhood Approach, a Community Coordinator canvases in the neighbourhood to promote the Lower Income Energy Efficiency Program for homeowners. When a tenant is encountered, the Community Coordinator provides the tenant with information on the Power Smart PAYS and the Lower Income Programs and obtains contact information for the landlord to communicate energy efficiency program opportunities.

While nine landlords to date have participated in Power Smart PAYS financing as outlined in Centra's response to CAC/Centra I-20(e)(iii), no landlords have applied for PAYS financing or the Lower Income Program under the Neighbourhood Power Smart Project. The Neighbourhood Power Smart Project is in the early stages of implementation.

CAC/CENTRA II-64

Reference: CAC / Centra I-20(e)(iii)

Please provide the low-income participation in the PAYS, HIP, and Water and Energy Saver programs.

ANSWER:

Manitoba Hydro does not require customers to submit household income in order to participate in the HIP and Water and Energy Saver Programs.

Manitoba Hydro requests financial information from participants in financing programs for the sole purpose of establishing creditworthiness and assessing a customer's ability to repay the loan. In the absence of corresponding household demographic information, PAYS participants cannot be classified as low-income under the LICO or LICO-125 criteria.

CAC/CENTRA II-65

Reference: CAC / Centra I-20(f)

Please confirm that (as shown in the response to CAC/CENTRA I-20 (e)(i)-(ii)) there is no program targeted to assisting landlords of lower income households to improve standard furnaces. If the statement is not confirmed, provide full and complete details of the program, to assist landlords of lower income households to improve standard furnaces.

ANSWER:

Under the Neighbourhood Power Smart Project, landlords can access PAYS financing to replace standard furnaces as outlined Centra's response to CAC/Centra II-63(f).

Landlords can also replace their standard efficiency furnaces through Centra's Furnace Replacement program provided an arrangement can be made to ensure the lower income tenant is realizing a substantial portion of the benefit of reduced heating costs. For example, Manitoba Hydro has made arrangements with Kinew Housing Corporation utilizing both the PAYS financing and Furnace Replacement Program to replace a number of standard efficiency furnaces as outlined under Centra's response to CAC/Centra II-66.

CAC/CENTRA II-66

Reference: CAC / Centra I-20(g)

Please confirm that (as shown in the response to CAC/CENTRA I-20 (e)(iii)) the number of lower income households living in rented quarters served by the Company's Furnace Replacement Program is zero. If not confirmed, please provide the numbers requested.

ANSWER:

Centra confirms the number of lower income households living in rented quarters served by the Furnace Replacement Program is zero.

Centra is currently working with Kinew Housing Corporation, a non-profit Aboriginal housing company providing housing to low income Aboriginal families, to replace standard efficient furnaces with funding provided through Power Smart PAYS Financing program and the Furnace Replacement Program.

CAC/CENTRA II-67

Reference: CAC / Centra I-20(h)

Please reconcile the difference in the number of boilers in low-income premises (LICO-125) as reported in (i) Table 5.6 of the 2009 Residential Energy Use Survey Report (p. 136) and (ii) the response to CAC/CENTRA I-20(h).

ANSWER:

The difference in the number of boilers in LICO 125 premises as reported in (i) Table 5.6 of the 2009 Residential Energy Use Survey Report - Low Income Cut-off (LICO) (p.136) and (ii) the response to CAC/Centra I-20(h) is due to the slight refinement of survey figures after the original filing of the report. Please see Centra's response to CAC/Centra I-20(a) for further details on the adjustments to the study.

CAC/CENTRA II-68

Reference: CAC / Centra I-20(i)

CAC/CENTRA I-20(i) requested “all Company plans” for process, impact, and all other evaluations and to “Include all documents.” The response stated that “The Lower Income Energy Efficiency Program (LIEEP) is presently being evaluated based on a draft evaluation plan.” However, no draft evaluation plan or any other document was provided.Please provide a copy of the documents as requested in the Information Request.

ANSWER:

Please see the attachment to this response for a copy of the final evaluation plan associated with LIEEP. The LIEEP is evaluated every year and the aggregated results are provided within the Power Smart Annual Review. The next Power Smart Annual Review is expected to be completed in the summer of 2013.

EVALUATION PLAN

Lower Income Energy Efficiency Program

Table of Contents

1.0 Evaluation Plan Objectives

The main objective of this report is to outline the process to be carried out in performing an annual evaluation of the Lower Income Energy Efficiency Program (LIEEP). The Evaluation Plan also serves as a mechanism for the Affordable Energy Department (AED), Customer Engineering Services (CES) and Power Smart Planning, Evaluation & Research (PSPER) to communicate and outline the following:

a) The evaluation objectives;
b) The results to be reported;
c) The data responsibilities of PSPER; and
d) The data responsibilities of AED/CES.

2.0 Program Background

LIEEP helps lower income customers retrofit their homes to energy efficient standards, thus increasing the comfort level of the home and decreasing the customer’s energy bills.

Energy savings are achieved by retrofitting qualified customers’ homes with energy efficient measures as recommended by the pre-retrofit in-home energy evaluation.

Incentives and administrative costs are covered by Power Smart, the Affordable Energy Fund (AEF), the Natural Gas Furnace Replacement Program (FRP) and external funding received from organizations such as the Province of Manitoba, non-government community groups and where available, other agencies such as Natural Resources Canada (NRCan). This mixture of funding makes the participant cost of the retrofits close to nil.

Evaluation results will be compared against the program’s Power Smart Plan targets to determine whether the program is meeting its projected targets.

3.0 Impact Evaluation Plan

The intent of the Impact Evaluation is to establish and record the net energy and demand impacts of LIEEP, and to determine the cost effectiveness of these impacts. Results of the Impact Evaluation are included in the Power Smart Annual Review (PSAR).

3.1 Impact Evaluation Objectives

The objectives of the Impact Evaluation are to:

a) Determine the energy and demand savings achieved through LIEEP.
b) Determine the cost effectiveness of the energy and demand savings achieved by applying the following economic tests:

   i. Total Resource Cost (TRC);
   ii. Levelized Utility Cost (LUC); and
   iii. Rate Impact Measure (RIM).

c) Conduct a variance analysis comparing achieved energy and demand savings and economic tests, against what was forecast.

d) Recommend methods for improving future data collection.

3.2 Impact Evaluation Methodology

3.2.1 Load Impact – Achievements by Measure Type

The load impact analysis will focus on factors that affect energy and demand savings for LIEEP. The analysis will consist of an engineering evaluation completed for each energy efficient measure type.

3.2.1.1 Water & Energy Saving Measures

1) Engineering Estimates of per Unit Impacts

a) Formulae

The following equations will be used to calculate per unit energy and demand savings resulting from the installation of water and energy saving measures (low-flow showerheads, faucet aerators and water heater pipe wrap):

i. Annual Energy Savings per Unit:

Annual Energy Savings per Unit (kW.h)	=	*Energy Consumption resulting from non-EE Measure (kW.h)*	-	*Energy Consumption resulting from EE Measure (kW.h)*

ii. Demand Savings per Unit:

$$\textit{Demand Savings per Unit (KW)} = \left\{ \textit{Watts used with non-EE Measure Installed (KW)} - \textit{Watts used with EE Measure Installed (KW)} \right\} \times \textit{Coincidence Peak Factor}$$

b) Data Sources

The data inputs for the equations listed in Section 3.2.1.1 1) a) are to be taken from the following sources:

Equation Variable	Data Source	Responsibility
Energy Consumption Resulting from non-EE Measure	In-home energy evaluation (specifies whether hot water tank is gas or electric) Residential Energy Use Survey "City of Winnipeg Water Supply 2008" report "Groundwater in Manitoba: Hydrogeology, Quality Concerns, Management" (1995), National Hydrology Research Institute "Potential Water and Energy Savings from Showerheads" (2006), Berkeley National Laboratory "Showerhead Summary" (2009) – Product testing (showerhead and faucet aerator flow rates) completed by Customer Engineering Services Water Energy Saver Program (WESP) survey results	Affordable Energy Dept. External Party: Energy Advisors Market Forecast Dept. Customer Engineering Services Marketing Programs Dept.
Energy Consumption Resulting from EE Measure	In-home energy evaluation (specifies whether hot water tank is gas or electric, and indicates which EE measures were installed) Residential Energy Use Survey "City of Winnipeg Water Supply 2008" report "Groundwater in Manitoba: Hydrogeology, Quality Concerns, Management" (1995), National Hydrology Research Institute "Potential Water and Energy Savings from Showerheads" (2006), Berkeley National Laboratory "Showerhead Summary" (2009) – Product testing (showerhead and faucet aerator flow rates) completed by Customer Engineering Services Water Energy Saver Program (WESP) survey results	Affordable Energy Dept. External Party: Energy Advisors Market Forecast Dept. Customer Engineering Services Marketing Programs Dept.

Equation Variable	Data Source	Responsibility
Watts used with non-EE Measure Installed	In-home energy evaluation (specifies whether hot water tank is gas or electric) Residential Energy Use Survey "City of Winnipeg Water Supply 2008" report "Groundwater in Manitoba: Hydrogeology, Quality Concerns, Management" (1995), National Hydrology Research Institute "Potential Water and Energy Savings from Showerheads" (2006), Berkeley National Laboratory "Showerhead Summary" (2009) – Product testing (showerhead and faucet aerator flow rates) completed by Customer Engineering Services Water Energy Saver Program (WESP) survey results	Affordable Energy Dept. External Party: Energy Advisors Market Forecast Dept. Customer Engineering Services Marketing Programs Dept.
Watts used with EE Measure Installed	In-home energy evaluation (specifies whether hot water tank is gas or electric, and indicates which EE measures were installed) Residential Energy Use Survey "City of Winnipeg Water Supply 2008" report "Groundwater in Manitoba: Hydrogeology, Quality Concerns, Management" (1995), National Hydrology Research Institute "Potential Water and Energy Savings from Showerheads" (2006), Berkeley National Laboratory "Showerhead Summary" (2009) – Product testing (showerhead and faucet aerator flow rates) completed by Customer Engineering Services Water Energy Saver Program (WESP) survey results	Affordable Energy Dept. External Party: Energy Advisors Market Forecast Dept. Customer Engineering Services Marketing Programs Dept.
Coincidence Peak Factor	Natural Resources Canada report on average home's hours of use 2010 Residential Vintage Model	Affordable Energy Dept. Customer Engineering Services Market Forecast Dept.

2) Engineering Estimates of Program Load Impacts

a) Formulae

The following equations will be used to calculate energy and demand savings at the program level:

i. Annual Energy Savings of the Program:

$$\textit{Annual Energy Savings (kW.h)} = \textit{(Rebated Sales - Free Riders + Free Drivers)} \times \textit{Annual Energy Savings per Unit (kW.h)} \times \textit{Persistence Factor}$$

ii. Demand Savings of the Program:

$$\textit{Demand Savings (KW)} = \textit{(Rebated Sales - Free Riders + Free Drivers)} \times \textit{Demand Savings per Unit (KW)} \times \textit{Persistence Factor}$$

b) Data Sources

The data inputs for the equations listed in Section 3.2.1.1 2) a) are to be taken from the following sources:

Equation Variable	Data Source	Responsibility
Rebated sales	Completed In-home Energy Evaluation	Affordable Energy Dept.
Free riders	n/a	n/a
Free drivers	n/a	n/a
Persistence Factor	Water Energy Saver Program (WESP) survey results	Affordable Energy Dept. Marketing Programs Dept. Power Smart Planning, Evaluation & Research

3) Definition of Variables

Refer to Glossary in Section 4.0 for definition of variables mentioned above.

3.2.1.2 Insulation

1) Engineering Estimates of per Unit Impacts

The per unit impact analysis will focus on factors affecting the energy and demand savings resulting from insulation improvements. The analysis will consist of an engineering evaluation using the following ASHRAE-recognized calculations.

a) Electric Demand

i. Formula

The following calculation is used to determine the per unit demand impact in KW on a per square foot basis. Heating values will be used to calculate winter peak, whereas peak in shoulder summer months is based on the on/off statistics for electric space heat[1]. It has been established that a net zero impact occurs on summer demand peak as attributable to air conditioning.

$$\text{Per Unit Demand Savings (KW)} = \left(\left\{ \frac{\text{ALF} \times \text{BGRF} \times \text{DTD}}{\text{HCCF} \times \text{HCE}} \right\} \times \left\{ \left(\frac{1}{[\text{CF} \times R_{\text{BEF}} + R_{\text{ADJ}}]} \right) - \left(\frac{1}{[\text{CF} \times R_{\text{AFT}} + R_{\text{ADJ}}]} \right) \right\} \right) \times \text{Coincidence Peak Factor}$$

Where:

- Air Leakage Factor (ALF) – This factor is used to account for the effect of air leakage on the energy performance of the home. In this calculation it is assumed that upon re-insulating a home, air leakage issues will be addressed/improved upon simultaneously.

- Below Grade Reduction Factor (BGRF) – A reduction factor used in calculating savings for basement and crawlspace measures due to the differing characteristics of heat/cooling loss/gain below grade.

- Design Temperature Difference (DTD) – This measures design heat/cooling loss as tabulated in the building code for a particular geographic location.

- Heating/Cooling Conversion Factor (HCCF) – The energy contained within a fuel.

[1] Source: Residential Energy Use Survey

- Heating/Cooling Efficiency (HCE) – The efficiency with which the heating/cooling value is extracted from the fuel to its intended purpose.

- Construction Factor (CF) – This factor reduces the nominal/rated R-value of the insulation improvement as per the typical losses that would be expected in actuality considering construction breaks in the insulation barrier (i.e. wall construction/studs).

- R-Value – Measures a material's resistance to heat flow in units of Fahrenheit degrees x hours x square feet per BTU. The higher the R-value of a material, the greater its insulating capability.
  R_{BEF} = R-value prior to re-insulation
  R_{AFT} = R-value after re-insulation
  R_{ADJ} = Adjustment factor for standard building materials

ii. Data Sources

The data inputs for the equation listed in Section 3.2.1.2 1) a) i) are to be taken from the following sources:

Equation Variable	Data Source	Responsibility
Air Leakage Factor	Statistically-derived modifier*	Customer Engineering Services
Below Grade Reduction Factor	Statistically-derived modifier*	Customer Engineering Services
Design Temperature Difference	Manitoba Building Code	Customer Engineering Services
Heating/Cooling Conversion Factor	Conversion factor (BTU to kW.h or cu.m), ASHRAE-recognized	Customer Engineering Services
Heating/Cooling Efficiency	Average market value, adjusted periodically as the market shifts its share of standard, mid and high efficiency units	Customer Engineering Services Market Forecast Dept.
Construction Factor	Statistically-derived modifier*	Customer Engineering Services
$R_{\text{BEFORE / AFTER}}$	Preliminary assessment by external party energy advisors Contractor's invoicing Random post-verification completed by external party energy advisors or Manitoba Hydro staff (20% sample)	External Party: Energy Advisors Contractor Affordable Energy Dept.
$R_{\text{ADJUSTMENT}}$	Statistically-derived modifier*	Customer Engineering Services
Coincidence Peak Factor	Natural Resources Canada report on average home's hours of use 2010 Residential Vintage Model	Affordable Energy Dept. Customer Engineering Services Market Forecast Dept.

*Used to better represent typical residential construction within the general formula.

b) Electric Energy

i. Formula

The following calculation identifies per unit savings in kW.h per square foot. Heating values are used for calculating energy savings in winter months and shoulder summer months[2]. Cooling values will be used to calculate additional summer energy savings for those applications submitted for homes with central air conditioning.

$$\text{Per Unit Energy Savings (kW.h)} = \text{Per unit Demand Savings (KW)} \times \text{HDD/CDD} \times \left\{ \frac{\text{C-Factor}}{\text{DTD}} \right\}$$

Where:

- Heating/Cooling Degree Days (HDD/CDD) – Expresses the relationship between outside and optimum inside temperature, assuming that to maintain a temperature of 21°C inside, the energy requirement will vary in proportion to the difference between the outside temperature and 18°C. A degree day is equal to one degree difference in a single day's mean temperature from that of 18°C.

- C-Factor – A constant based on several variables relating to the construction, occupancy and geographic location of the building.

- Design Temperature Difference (DTD) – This measures design heat/cooling loss as tabulated in the building code for a particular geographic location.

ii. Data Sources

The data inputs for the equation listed in Section 3.2.1.2 1) b) i) are to be taken from the following sources:

Equation Variable	Data Source	Responsibility
Heating/Cooling Degree Days	Manitoba Building Code	Customer Engineering Services
C-Factor	Statistically-derived modifier*	Customer Engineering Services
Design Temperature Difference	Manitoba Building Code	Customer Engineering Services

*Used to better represent typical residential construction within the general formula.

[2] Source: Residential Energy Use Survey

c) Natural Gas Energy

i. Formula

The following calculation identifies per unit savings in m^3 per square foot.

$$\text{Per Unit Energy Savings (cu.m)} = \left\{ \frac{\text{ALF} \times \text{BGRF} \times \text{HDD/CDD} \times \text{C-Factor}}{\text{HCCF} \times \text{HCE}} \right\} \times \left\{ \left(\frac{1}{[\text{CF} \times R_{\text{BEF}} + R_{\text{ADJ}}]} \right) - \left(\frac{1}{[\text{CF} \times R_{\text{AFT}} + R_{\text{ADJ}}]} \right) \right\}$$

Where:

- Air Leakage Factor (ALF) – This factor is used to account for the effect of air leakage on the energy performance of the home. In this calculation it is assumed that upon re-insulating a home, air leakage issues will be addressed/improved upon simultaneously.

- Below Grade Reduction Factor (BGRF) – A reduction factor used in calculating savings for basement and crawlspace measures due to the differing characteristics of heat/cooling loss/gain below grade.

- Heating/Cooling Degree Days (HDD/CDD) – Expresses the relationship between outside and optimum inside temperature, assuming that to maintain a temperature of 21°C inside, the energy requirement will vary in proportion to the difference between the outside temperature and 18°C. A degree day is equal to one degree difference in a single day's mean temperature from that of 18°C.

- C-Factor – A constant based on several variables relating to the construction, occupancy and geographic location of the building.

- Heating/Cooling Conversion Factor (HCCF) – The energy contained within a fuel.

- Heating/Cooling Efficiency (HCE) – The efficiency with which the heating/cooling value is extracted from the fuel to its intended purpose.

- Construction Factor (CF) – This factor reduces the nominal/rated R-value of the insulation improvement as per the typical losses that would be expected in actuality considering construction breaks in the insulation barrier (i.e. wall construction/studs).

- R-Value – Measures a material's resistance to heat flow in units of Fahrenheit degrees x hours x square feet per Btu. The higher the R-value of a material, the greater its insulating capability.
  R_{BEF} = R-value prior to re-insulation
  R_{AFT} = R-value after re-insulation
  R_{ADJ} = Adjustment factor for standard building materials

ii. Data Sources

The data inputs for the equations listed in Section 3.2.1.2 1) c) i) are to be taken from the following sources:

Equation Variable	Data Source	Responsibility
Air Leakage Factor	Statistically-derived modifier*	Customer Engineering Services
Below Grade Reduction Factor	Statistically-derived modifier*	Customer Engineering Services
Heating/Cooling Degree Days	Manitoba Building Code	Customer Engineering Services
C-Factor	Statistically-derived modifier*	Customer Engineering Services
Heating/Cooling Conversion Factor	Conversion factor (BTU to kW.h or cu.m)	Customer Engineering Services
Heating/Cooling Efficiency	Average market value, adjusted periodically as the market shifts its share of standard, mid and high efficiency units.	Customer Engineering Services Market Forecast Dept.
Construction Factor	Statistically-derived modifier*	Customer Engineering Services
$R_{BEFORE / AFTER}$	Preliminary assessment by external party energy advisors Contractor's invoicing Random post-verification completed by external party energy advisors or Manitoba Hydro staff (20% sample)	External Party: Energy Advisors Contractor Affordable Energy Dept.
$R_{ADJUSTMENT}$	Statistically-derived modifier*	Customer Engineering Services

*Used to better represent typical residential construction within the general formula.

2) Engineering Estimates of Program Load Impacts

a) Formulae

The following calculations are used to determine the program's energy and demand savings.

Demand Savings (MW) = *(Rebated Sales - Free Riders + Free Drivers)* x *Demand Savings per Unit (KW)*

Annual Energy Savings (kW.h) = *(Rebated Sales - Free Riders + Free Drivers)* x *Annual Energy Savings per Unit (kW.h)*

Annual Energy Savings (m^3) = *(Rebated Sales - Free Riders + Free Drivers)* x *Annual Energy Savings per Unit (m^3)*

b) Data Sources

The data inputs for the equations listed in Section 3.2.1.2 2) a) are to be taken from the following sources:

Equation Variable	Data Source	Responsibility
Rebated Sales	Completed In-home Energy Evaluation	Affordable Energy Dept.
Free Riders	n/a	n/a
Free Drivers	n/a	n/a

*Used to better represent typical residential construction within the general formulae.

3.2.1.3 High Efficiency Natural Gas Furnaces & Boilers

1) Engineering Estimates of per Unit Impacts

a) Formula

The following equation will be used to calculate per unit energy savings resulting from the installation of high efficiency natural gas furnaces and boilers:

Annual Energy Savings per Unit:

$$\text{Annual Energy Savings per Unit (cu.m)} = \left\{ \text{Consumption with standard efficiency furnace/boiler (cu.m)} - \text{Consumption with high efficiency furnace/boiler (cu.m)} \right\}$$

b) Data Sources

The data inputs for the equation listed in Section 3.2.1.3 1) a) are to be taken from the following sources:

Equation Variable	Data Source	Responsibility
Consumption with standard efficiency furnace/boiler	Residential Energy Use Survey data regarding averages for overall consumption and furnace/boiler efficiency, adjusted to reflect the average size of a lower income home based on Market Forecast data.	Affordable Energy Dept. Customer Engineering Services Market Forecast Dept.
Consumption with high efficiency furnace/boiler	Residential Energy Use Survey data regarding averages for overall consumption and furnace/boiler efficiency, adjusted to reflect the average size of a lower income home based on Market Forecast data.	Affordable Energy Dept. Customer Engineering Services Market Forecast Dept.

2) Engineering Estimates of Program Load Impacts

a) Formula

The following equation will be used to calculate energy savings at the program level:

i. Annual Energy Savings of the Program:

$$\textit{Annual Energy Savings (cu.m)} = \textit{(Rebated Sales - Free Riders + Free Drivers)} \times \textit{Annual Energy Savings per Unit (cu.m)}$$

b) Data Sources

The data inputs for the equation listed in Section 3.2.1.3 2) a) are to be taken from the following sources:

Equation Variable	Data Source	Responsibility
Rebated sales	Completed In-home Energy Evaluation	Affordable Energy Dept.
Free riders	n/a	Affordable Energy Dept.
Free drivers	n/a	n/a

3.2.1.4 Lighting

1) Engineering Estimates of per Unit Impacts

a) Formulae

The following equations will be used to calculate per unit energy and demand savings resulting from the installation of compact fluorescent lamps (CFLs):

i) Annual Energy Savings per Unit:

$$\textit{Annual Energy Savings per Unit (kW.h)} = \left\{ \textit{Consumption with Base Measures Installed (KW)} - \textit{Consumption with EE Measures Installed (KW)} \right\} \times \textit{Annual Hours of Operation} \times \textit{Heating/Cooling Interactive Effects}$$

ii) Demand Savings per Unit:

$$\textit{Demand Savings per Unit (KW)} = \left\{ \begin{array}{c}\textit{Consumption with Base Measures Installed (KW)}\end{array} - \begin{array}{c}\textit{Consumption with EE Measures Installed (KW)}\end{array} \right\} \times \textit{Heating/Cooling Interactive Effects} \times \textit{Coincidence Peak Factor}$$

b) Data Sources

The data inputs for the equations listed in Section 3.2.1.4 1) a) are to be taken from the following sources:

Equation Variable	Data Source	Responsibility
Consumption with base measures installed	Each participant is provided three 13-watt CFLs & three 23-watt CFLs. LIEEP assumes that each 13-watt CFL replaced a 60-watt incandescent bulb, and each 23-watt CFL replaced a 100-watt incandescent bulb.	Affordable Energy Dept. Marketing Programs Dept.
Consumption with EE measures installed	In-home energy assessment (details which lighting technologies were either installed or left at home) Nameplate wattage of lighting technologies installed (verified by CSA)	Affordable Energy Dept. External Party: Energy Advisor
Annual hours of operation	Natural Resources Canada report on average home's hours of use	Affordable Energy Dept. Customer Engineering Services
Heating/Cooling interactive effects	Natural Resources Canada & CEATI model homes In-home energy assessment (specifies heating system and type of residence)	Affordable Energy Dept. External Party: Energy Advisor Customer Engineering Services
Coincidence peak factor	Natural Resources Canada report on average home's hours of use 2010 Residential Vintage Model	Affordable Energy Dept. Customer Engineering Services Market Forecast Dept.

2) Engineering Estimates of Program Load Impacts

a) Formulae

The following equations will be used to calculate energy and demand savings at the program level:

a. Annual Energy Savings of the Program:

$$\text{Annual Energy Savings (kW.h)} = \text{(Rebated Sales - Free Riders + Free Drivers)} \times \text{Annual Energy Savings per Unit (kW.h)} \times \text{Persistence Factor}$$

b. Demand Savings of the Program:

$$\text{Demand Savings (KW)} = \text{(Rebated Sales - Free Riders + Free Drivers)} \times \text{Demand Savings per Unit (KW)} \times \text{Persistence Factor}$$

b) Data Sources

The data inputs for the equations listed in Section 3.2.1.4 2) a) are to be taken from the following sources:

Equation Variable	Data Source	Responsibility
Rebated sales	Completed In-home Energy Evaluation	Affordable Energy Dept.
Free riders	n/a	n/a
Free drivers	n/a	n/a
Persistence Factor	Water & Energy Saving Program (WESP) survey results Collaboration with Strategic Lighting Initiative Committee & CSA members Natural Resources Canada studies	Affordable Energy Dept. Marketing Programs Dept. Customer Engineering Services

3.2.1.5 Air Sealing Measures

1) Engineering Estimates of per Unit Impacts

a) Formulae

The following equations will be used to calculate per unit energy and demand savings resulting from the installation of air sealing measures (caulking, gasket packages, socket caps and window sealing kits):

i. Annual Energy Savings per Unit:

$$\textit{Annual Energy Savings per Unit (kW.h)} = \textit{Energy Consumption of Heating System without Air Sealing Measures Installed (kW.h)} - \textit{Energy Consumption of Heating System with Air Sealing Measures Installed (kW.h)}$$

ii. Demand Savings per Unit:

$$\textit{Demand Savings per Unit (KW)} = \left\{ \textit{Watts used by Heating System without Air Sealing Measures Installed (KW)} - \textit{Watts used by Heating System with Air Sealing Measures Installed (KW)} \right\} \times \textit{Coincidence Peak Factor}$$

b) Data Sources

The data inputs for the equations listed in Section 3.2.1.6 1) a) are to be taken from the following sources:

Equation Variable	Data Source	Responsibility
Energy Consumption of Heating System without Air Sealing Measures Installed	In-home energy evaluation (provides heating system details) Historical LIEEP ecoENERGY audit results (blower door test)	Affordable Energy Dept. External Party: Energy Advisors
Energy Consumption of Heating System with Air Sealing Measures Installed	In-home energy evaluation (provides heating system details, and indicates which EE measures were installed) Historical LIEEP ecoENERGY audit results (blower door test)	Affordable Energy Dept. External Party: Energy Advisors

Equation Variable	Data Source	Responsibility
Watts used by Heating System without Air Sealing Measures Installed	In-home energy evaluation (provides heating system details) Historical LIEEP ecoENERGY audit results (blower door test)	Affordable Energy Dept. External Party: Energy Advisors
Watts used by Heating System with Air Sealing Measures Installed	In-home energy evaluation (provides heating system details, and indicates which EE measures were installed) Historical LIEEP ecoENERGY audit results (blower door test)	Affordable Energy Dept. External Party: Energy Advisors
Coincidence peak factor	Natural Resources Canada report on average home's hours of use 2010 Residential Vintage Model	Affordable Energy Dept. Customer Engineering Services Market Forecast Dept.

2) Engineering Estimates of Program Load Impacts

a) Formulae

The following equations will be used to calculate energy and demand savings at the program level:

i. Annual Energy Savings of the Program:

Annual Energy Savings (kW.h) = *(Rebated Sales - Free Riders + Free Drivers)* x *Annual Energy Savings per Unit (kW.h)*

ii. Demand Savings of the Program:

Demand Savings (KW) = *(Rebated Sales - Free Riders + Free Drivers)* x *Demand Savings per Unit (KW)*

b) Data Sources

The data inputs for the equations listed in Section 3.2.1.6 2) a) are to be taken from the following sources:

Equation Variable	Data Source	Responsibility
Rebated sales	Completed In-home Energy Evaluation	Affordable Energy Dept.
Free riders	n/a	n/a
Free drivers	n/a	n/a

3.2.1.6 Combined Measures (Interactive Effects)

In order to account for interactive effects occurring when building envelope and heating devices are coincidentally improved, the LIEEP uses a formula that assigns weight to the two broad classes of measures (insulation and furnace/boiler) in proportion to their independent savings. The effect is a reduction in overall savings compared to the straight aggregate of the individual savings of insulation and furnace/boiler measures.

1) Engineering Estimates of per Unit Impacts

The following equation will be used to calculate per unit energy savings when building envelope and heating devices are coincidentally improved. This formula utilizes GJ, to which both kW.h and cu.m can be converted. Equivalent kW.h for both gas and electricity can also be used; however, an alternative to the constant “93” would need to be utilized.

$$\text{Coincidental per Unit Savings (GJ)} = \text{HVAC per Unit Savings (GJ)} + \text{BE per Unit Savings (GJ)} - \left\{ \frac{\text{HVAC per Unit Savings (GJ)} \times \text{BE per Unit Savings (GJ)}}{93} \right\}$$

2) Engineering Estimates of Program Load Impacts

The following equation will be used to calculate energy savings at the program level:

$$\textit{Coincidental Total Savings (GJ)} = \textit{(Rebated Sales - Free Riders + Free Drivers)} \times \textit{Coincidental per Unit Savings (GJ)}$$

3.2.2 Load Impact – Overall Program Achievements

Once energy and demand savings are determined for each energy efficient measure type, they are combined to provide total program energy and demand savings. As noted in Section 3.2.1.6, savings have been adjusted to account for interactive effects occurring when building envelope and heating equipment are coincidentally improved. This adjustment provides a more accurate representation of overall program achievements.

3.2.3 Load Impact – Cost Effectiveness Metrics

Manitoba Hydro determines the cost effectiveness of a program's DSM activity based upon the results of the following benefit/cost analysis metrics:

Total Resource Cost (TRC)

The Total Resource Cost (TRC) measures the cost effectiveness of a product or program from the perspective of the utility and its customers. Incentives do not impact this measure as they are seen as a transfer payment between the utility and the customer. A TRC ratio greater than 1.0 indicates that a program is cost effective.

The TRC requires the following information:

a) Marginal Benefits

   Electric: The present value of the 30-year stream of revenue realized by Manitoba Hydro from conserved electricity being sold in the export market, the avoided cost of new infrastructure (ex. transmission facilities) and measurable non-energy benefits (ex. water savings).

   Natural Gas: The present value of the 30-year stream of the avoided cost of Manitoba Hydro purchasing natural gas, avoided transportation costs, the value of reduced greenhouse gas emissions and measurable non-energy benefits (ex. water savings).

b) Incremental Product Cost

   The incremental product cost is the difference in costs between the EE technology promoted by the program and the standard technology that would have been installed in the absence of the program. This is the incremental costs associated with installing the EE technology regardless of who pays.

c) Total Program Administrative Costs

   Program operating costs incurred by Manitoba Hydro for staff involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with running the Power Smart program, except for customer incentive costs.

$$TRC = \frac{PV\ (Marginal\ Benefits)}{PV\ (Incremental\ Product\ Cost + Total\ Program\ Admin\ Costs)}$$

Levelized Utility Cost (LUC)

The Levelized Utility Cost (LUC) provides an economic cost value for the energy saved through a Power Smart program. The LUC provides the total cost of the conserved energy on a per unit basis levelized over a fixed period of time. The cost value allows for comparison to other supply options and other DSM programs over different time frames.

The LUC requires the following information:

a) Utility Program Administrative Cost

   Program operating costs incurred by Manitoba Hydro for staff involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with running the Power Smart program, except for customer incentive costs.

b) Incentives

   Funds provided by Manitoba Hydro to the participant associated with implementing the Power Smart measure. Examples include cash-rebates, cash payments, non-cash low interest loans, reduced equipment costs, bill credits/discounts, free merchandise and no-fee services.

c) Energy

   The annual energy (kW.h or m^3) saved through a Power Smart program.

$$LUC = \frac{PV\ (\text{Utility Program Admin Costs + Incentives})}{PV\ (\text{Energy})}$$

Rate Impact Measure (RIM)

The Rate Impact Measure (RIM) provides an indication of the long term impact on rates due to proposed Power Smart initiatives. This test considers all the costs incurred in operating a program and indicates the cost effectiveness of a program from the ratepayer's perspective. A RIM ratio less than 1.0 indicates that per kW.h & KW rates for customers will have to increase in order to achieve the utility's revenue requirements.

The RIM requires the following information:

a) Utility Marginal Benefits

   Electric: The present value of the 30-year stream of revenue realized by Manitoba Hydro from conserved electricity being sold in the export market and the avoided cost of new infrastructure (ex. transmission facilities).

   Natural Gas: The present value of the 30-year stream of the avoided cost of Manitoba Hydro purchasing natural gas and avoided transportation costs.

b) Revenue Loss

   Revenue loss includes Manitoba Hydro's lost revenue associated with the participants' reduced energy consumption.

c) Utility Program Administrative Cost

   Program operating costs incurred by Manitoba Hydro for staff involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with running the Power Smart program, except for customer incentive costs.

d) Incentives

   Funds provided by Manitoba Hydro to the participant associated with implementing the Power Smart measure. Examples include cash-rebates, cash payments, non-cash low interest loans, reduced equipment costs, bill credits/discounts, free merchandise and no-fee services.

$$RIM = \frac{PV\ (Utility\ Marginal\ Benefits)}{PV\ (Revenue\ Loss + Utility\ Program\ Admin\ Cost + Incentives)}$$

3.3 Aggregation of Data

The following data is to be aggregated from the following sources:

Data Item	Aggregated by	Source
Total Incremental Participant Cost	Affordable Energy Dept.	Application Form In-home Energy Evaluation
Utility & Program Costs	Power Smart Planning, Evaluation & Research Dept.	Manitoba Hydro's SAP accounting reports
Affordable Energy Fund & Furnace Replacement Program Costs	Affordable Energy Dept. Power Smart Planning, Evaluation & Research Dept.	Manitoba Hydro's SAP accounting reports
External Funding	Affordable Energy Dept.	Community Groups, Manitoba Government, Natural Resources Canada
Program Energy and Demand Savings	Power Smart Planning, Evaluation & Research Dept.	Refer to Section 3.2.1 for each measure type

3.4 Power Smart Plan Targets

The actual program results will be compared to program targets using the following measures:

- Number of participants/rebated sales
- Number of free riders
- Number of free drivers
- GW.h savings
- MW savings
- Natural gas savings (m^3)
- Program costs (without incentives)
- Affordable Energy Fund & Furnace Replacement Program costs
- External funding
- Incentive costs
- Total Resource Cost (TRC)
- Levelized Utility Cost (LUC)
- Rate Impact Measure (RIM)

3.5 Impact Evaluation Report

The annual Impact Evaluation will cover the following:

- Gross number of program participants/rebated sales
- Gross energy (GW.h or m^3) savings
- Gross winter a.m. demand (MW) savings
- Gross winter p.m. demand (MW) savings
- Gross summer demand (MW) savings
- Number of free riders
- Number of free drivers
- Net number of program participants
- Net energy (GW.h or m^3) savings
- Net winter a.m. demand (MW) savings
- Net winter p.m. demand (MW) savings
- Net summer demand (MW) savings
- Program benefits and costs
- Affordable Energy Fund & Furnace Replacement Program costs
- External funding
- Cost effectiveness:
    - Total Resource Cost (TRC)
    - Levelized Utility Cost (LUC)
    - Rate Impact Measure (RIM)
- Comparison of actual results to projected targets, with an explanation of variances
- Recommendations

4.0 Glossary

i. **Rebated Sale –** A sale in which a rebate/incentive is provided to the customer.
Program Example: A participating house that has completed at least one of the recommended LIEEP retrofits.

ii. **Free Rider –** A program participant who was already planning to purchase the EE technology. Even though the incentive didn't influence their purchase decision, they received the incentive because one was available.
Program Example: There are no free riders in LIEEP as the participating customers are thought to not have the financial means to make the energy efficient upgrades to their homes.

iii. **Free Driver –** A customer that because of the information provided by the Power Smart Program (i.e. manuals, software, etc.), became aware of the potential savings and purchased the EE technology without receiving the incentive.
Program Example: There are no free drivers in LIEEP as the participating customers are thought to not have the financial means to make the energy efficient upgrades to their homes.

iv. **Persistence Factor –** The tendency for the EE technology to remain installed for its entire useful life.
Program Example: The installation rate is likely to be 100% for most of the technologies associated with LIEEP, as the low-cost/no-cost technologies are installed by an energy evaluator[3], and a contractor installs the insulation and furnaces, which are permanent fixtures in a home. Also, there is a low likelihood of product removal by the homeowner, with CFL bulbs and water saving measures (i.e. low-flow showerheads) being possibilities.

v. **Interactive Effects Factor –** The effect that a change in one end-use's energy consumption has on another end-use's energy consumption.
Program Example: For LIEEP, interactive effects are considered for CFLs and/or if a customer installs both insulation and a high efficiency furnace.

vi. **Coincidence Peak Factor –** The customer's load at the time Manitoba Hydro experiences its greatest demand for electricity.

[3] In some instances, the energy evaluator will leave a low-cost/no-cost item with the homeowner for them to install at a later date. This applies to air sealing items in particular (i.e. caulking or electrical socket caps), as well as CFLs.

CAC/CENTRA II-69

Reference: CAC / Centra I-20(k)

Please provide the complete basis for the statement in the response to CAC/CENTRA I-20(k) that "Centra does not believe there is a notable impact on the items identified that result from the Corporation's investments in DSM for lower income households to warrant the expense of such an undertaking." Include all research results and other documents.

ANSWER:

As stated in Centra's response to CAC/Centra I-20(k), Centra has not undertaken any research on this matter.

CAC/CENTRA II-70

Reference: CAC / Centra I-20(t)

CAC/CENTRA I-20(t) asked for "the difference in the reports of unaided awareness between the report for the Period Ending Sept. 30, 2012 (Filing, Appendix 7.3 at 82) and all earlier reports." The response only states "Unaided awareness in all reports prior to the Period Ending Sept. 30, 2012 includes Unaided Recall – Program Details and Unaided Recall – Program Name. This includes those that were aware of the details of LIEEP without prompting but could not recall the program name itself, and those that were aware of the program name without prompting." Thus the response does not address the differences asked about, which remain unexplained. Please provide the response as requested in the Information Request.

ANSWER:

Centra has assumed the intended reference in this question is to CAC/Centra I-20(u).

In all reports prior to the Period ending Sept. 30, 2012, the percentage of Unaided Awareness was shown as one total value that included both "Unaided Recall – Program Details" and "Unaided Recall – Program Name". The report for the Period ending Sept. 30 2012 (Filing, Appendix 7.3 at 82), was the first period where total Unaided Awareness was displayed as two separate components "Unaided Recall – Program Details" and "Unaided Recall – Program Name". Unaided recall of program details refers to respondents able to independently recall details of the Lower Income Energy Efficiency Program. Unaided recall of program name refers to respondents able to independently recall the Lower Income Energy Efficiency Program name. These two separate components together make up total

Unaided Awareness. The following chart presents for the values of Unaided and Aided Awareness in each period the survey was undertaken.

LIEEP Program Awareness	Unaided Recall - Program Details (A)	Unaided Recall - Program Name (B)	Unaided Awareness (C=A+B)	Aided Awareness (D)	Overall (E=C+D)
Jul-10	26%	7%	33%	34%	67%
Oct-10	22%	9%	31%	45%	77%
Jan-11	33%	3%	36%	36%	72%
Apr-11	24%	5%	29%	41%	70%
Jan-12	21%	3%	24%	53%	77%
Jul-12	37%	10%	47%	28%	75%
Jan-13	17%	1%	18%	58%	76%

Note: Totals may not add due to rounding.

<u>CAC/CENTRA II-71</u>

Reference: CAC / Centra I-20(x) and (cc)

Please provide all evidence relied upon, including full and complete documentation, for quantifying the 10% adder used in the SCT. Include identification of each non-energy benefit and/or indirect benefit intended to be included by means of the adder.

<u>ANSWER</u>:

The 10% adder was determined based upon a qualitative review of non-energy benefits used in cost effectiveness calculations by other utilities at the time the societal cost metric was introduced within the Corporation's analyses. No specific non-energy benefits have been quantified; rather the 10% is presented as a proxy for non-measurable non-energy benefits.

CAC/CENTRA II-72

Reference: CAC / Centra I-20(bb)

Please provide all evidence relied upon, including full and complete documentation, for establishing the "proxy for the breakdown is 94% of the value arising from the avoided cost of purchasing natural gas and avoided transportation costs and 6% arising from the value of reduced greenhouse gas emission reductions".

ANSWER:

This proxy was calculated by taking the 30-year Net Present Value (NPV) of the forecast value of reduced greenhouse gas emission reductions as a percent of the 30-year NPV of the forecast total natural gas marginal value.

	Cents/cu.m	Percent
30-year levelized value of reduced greenhouse gas emissions	$0.02	6%
30-year levelized avoided cost of purchasing natural gas and avoided transportation costs	$0.33	94%
30-year NPV of total natural gas marginal value	$0.35	100%

CAC/CENTRA II-73

Reference: CAC / Centra I-20(dd)

a) Please state the full average cost of a furnace replacement.

ANSWER:

Please see Centra's response to PUB/Centra I-59(c) for the average cost of a furnace replacement.

CAC/CENTRA II-73

Reference: CAC / Centra I-20(dd)

b) Please state the full average cost of a boiler replacement.

ANSWER:

Please see Centra's response to PUB/Centra I-59(c) for the average cost of a boiler replacement.

CAC/CENTRA II-74

Reference: CAC / Centra I-20(ee) and (gg)(b)

Please describe in full all coordination between Company programs for lower income households and provincial funds and programs. If there is none, explain in full why the Company has determined this is desirable.

ANSWER:

In the early stages of the Lower Income Energy Efficiency Program (LIEEP), Centra met with provincial partners and community representatives to discuss funding commitments for community based initiatives such as the Centennial Neighbourhood Pilot, North End Community Renewal Corporation, and Brandon Neighbourhood Renewal Corporation working with social enterprise organizations such as BUILD and BEEP. Based on these meetings, it was concluded on a go forward basis Centra would provide annual funding for energy efficiency measures and provincial partners would contribute annual funding for labour.

Centra meets with other parties (provincial as required) as new initiatives arise. As with Manitoba Housing, Centra has streamlined the distribution process by providing Manitoba Housing with the energy efficiency measures funding allowing one provincial body to make payment to BUILD and BEEP.

All other low income participation outside of these community based initiatives is funded solely through the LIEEP.

CAC/CENTRA II-75

Reference: CAC / Centra I-20(ff)(a)

Please provide the eligibility criteria as defined by the Corporation and fully describe all considerations to change the eligibility criteria. Please state also the method by which the grant is computed and all considerations to change the amount of the grant and the maximum number of grants available.

ANSWER:

An increase to the Neighbours Helping Neighbours (NHN) program grant maximum was reviewed and approved by the Community Council, which oversees the program, in February 2010 as an accommodation for an observed increase in average bill arrears of NHN participants. In addition, the program eligibility criteria was last reviewed in June 2010 and approved by the Community Council. The Community Council has representation from The Salvation Army, Manitoba Hydro and various community partners, such as Winnipeg Regional Housing Authority, United Way, and the Central Neighbourhood Development Corporation. As outlined in Centra's response to CAC/Centra I-20(ff)(e), qualifying customers are entitled to a maximum of two financial grants.

Eligibility Criteria:

Applicants must live in the Manitoba Hydro service area;

1. Applicants must have an arrears notice or shut off/disconnection notice or have a past due balance;
2. Circumstances have arisen which have depleted an individual's or family's immediate cash resources such as a critical event/unexpected crisis causing

interruption of income or increase in expenses, and which has occurred in the past 90 days leaving the individual or family with inadequate resources to meet their heating/hydro needs;

3. Applicant must be income eligible;
4. Applicant must have proof of income for current year for all household members (most recent paystubs from all employment, account books for self employed, etc);
5. Applicant must have applied to all other existing systems such as calling Manitoba Hydro and attempting to make alternative payment arrangements;
6. Applicants must sign an information release form; and
7. Applicants are eligible for assistance once per year, to a maximum of 2 financial grants.

Note: The above criteria are guidelines and on occasion, due to extenuating circumstances, applicants may be given special consideration. In these cases, NHN program staff will consult with the Salvation Army Assistant Program Coordinator.

The grant is applied based on the “Monthly Income Remaining Per Person” as per the following:

Monthly Income Remaining per Person	Proposed Grant Amount
Over $499	$150 + External Factor(s)
$400 - $499	$200 + External Factor(s)
$300 - $399	$250 + External Factor(s)
Less than $300	$300 + External Factor(s)

Where “Monthly Income Remaining per Person” is determined by:

{Monthly Income} minus {Monthly Rent/Mortgage} = Monthly Income Remaining

{Monthly Income Remaining} divided by {Number of Residents} = Monthly Income Remaining Per Person

Recognizing that external factors can affect individual situations, $30 is added for each of the following circumstances listed below to the maximum grant of $450.00:

- Disability
- Recent loss of employment
- Recent separation or divorce
- Recent death in the family
- Lack of support system

CAC/CENTRA II-76

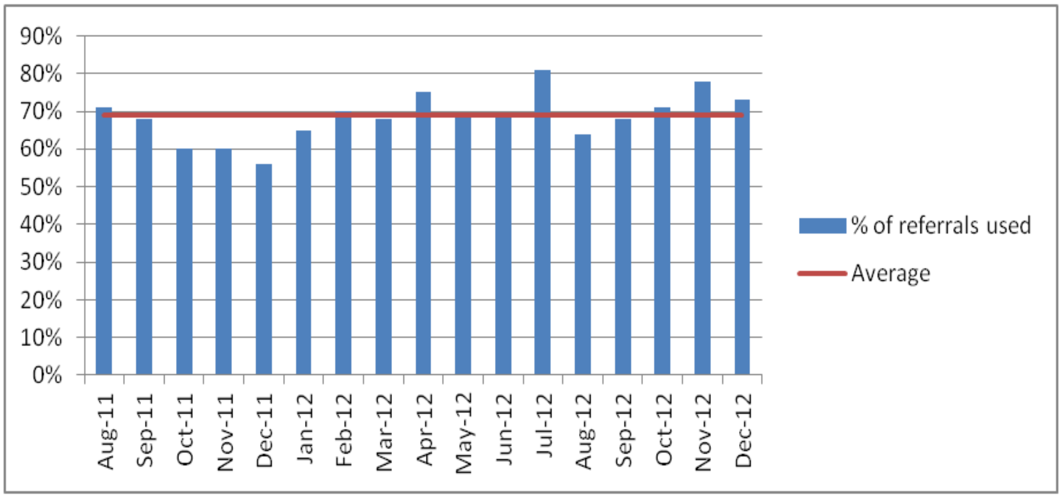
Reference: CAC / Centra I-20(ff)(d)

Please provide all evidence relied upon, including full and complete documentation, for "The belief … that by working to connect customers with available support services, they will be in a better position to manage possible future events" without need of an additional grant.

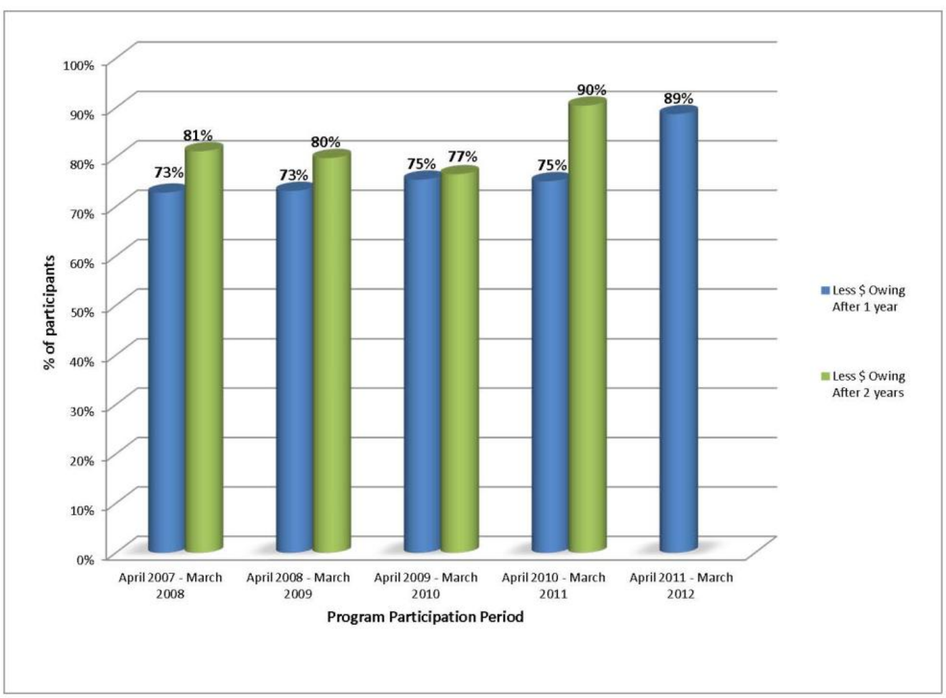
ANSWER:

As stated in Centra's response to CAC/Centra I-20(ff)(e), qualifying customers are eligible for a maximum of two grants under the Neighbours Helping Neighbours program.

Since August 2011, The Salvation Army, at Manitoba Hydro's request, instituted a follow-up assessment with NHN clients 30 days after receiving grant monies and program referrals to determine the referral uptake rate and to gauge whether clients deemed the referrals useful. The following table illustrates the overall usage rate for referrals provided under the NHN. Overall, almost 70% of the program referrals provided to NHN clients have been used.



In addition, beginning in April 2007, Manitoba Hydro began monitoring the account status of NHN participants to assess the longer term effect of the program on customer account balances. Since April 1, 2007 to March 31, 2013, 3 883 grants have been awarded with 83 grants being second time participants (or 0.021%).The results below indicate that the majority of grant recipients (73% or greater) have experienced significant improvement in their arrears situation since participating in the program.



CAC/CENTRA II-77

Reference: PUB / Centra I-54(b) and PUB / Centra I-55

a) Please reconcile the lower income expenditures shown in PUB/Centra I-54 (b) and PUB/Centra I-55.

ANSWER:

The expenditures shown in PUB/Centra I-55 are solely the natural gas Power Smart expenditures, whereas the expenditures shown in PUB/Centra I-54(b) include natural gas Power Smart, Furnace Replacement Program, and apportioned Affordable Energy Fund expenditures.

CAC/CENTRA II-77

Reference: PUB / Centra I-54(b) and PUB / Centra I-55

b) Please confirm that Centra has conducted no process evaluation of any lower income program. If not confirmed, provide all such evaluations.

ANSWER:

An overall review of the Corporation's Power Smart portfolio was performed by Dunsky Energy Consulting in 2009. The Lower Income Energy Efficiency Program was discussed in depth and the Consultant rated the program as a "Leader" in its comparisons to other providers they considered to be leaders or advanced performers. This portfolio review, titled "Leadership in Energy Efficiency: Comparing Manitoba Hydro's Power Smart with Leading North American Strategies", was previously filed with the PUB in response to PUB/MH I-155 in the 2010/11 & 2011/12 Manitoba Hydro Electric GRA (Appendix 25).

CAC/CENTRA II-78

Reference: PUB / Centra I-57(c)

a) Please provide the full rationale for using the discount rate of 6.1% in evaluating savings and benefits (PUB/Centra I-57(c)). Include all relevant documents.

ANSWER:

Centra uses its real weighted average cost of capital (WACC) as the discount rate when evaluating DSM program savings, costs and benefits. Centra's real WACC at the time the 2011 Power Smart Plan was undertaken was 6.1%.

CAC/CENTRA II-78

b) Please provide the measure life used in evaluating the benefits of each lower income measure. Include documentation and all other bases for each measure life.

ANSWER:

The following measure lives are used for technologies impacting natural gas use including in the Lower Income Energy Efficiency Program:

Technology	Measure Life (years)
High-efficiency natural gas furnace	25
High-efficiency boiler	25
Insulation (attic, wall, basement, crawlspace)	30
Low-flow showerhead	15
Handheld showerhead	15
Bathroom faucet aerator	15
Kitchen faucet aerator	15
Pipe wrap	15
Caulking	15
Electric socket gasket	15

Measure lives were determined from research completed by program engineering staff.

CAC/CENTRA II-78

c) Please describe in full the methodology used for evaluating savings, e.g. but not by way of limitation, establishment of baselines, billing analysis, selection of control group, sample sizes and criteria for selection and weighting, engineering estimates, time periods analyzed (including duration), and/or modeling. Include all documentation of how the chosen method is applied to each lower income measure.

ANSWER:

Please see Centra's response to CAC/Centra II-68.

CAC/CENTRA II-78

d) Please state and document the confidence level and precision of each savings evaluation estimate.

ANSWER:

Please see Centra's response to CAC/Centra II-68.

CAC/CENTRA II-78

e) Please describe the quality control (QC) protocol for each lower income measure and provide all documentation. Separately describe each level of QC, e.g., paperwork, in-process inspection, final inspection, including the percentage of jobs subject to each.

ANSWER:

To ensure the appropriate level of savings and benefits are attributed to a participating Lower Income Energy Efficiency Program (LIEEP) home, a number of processes are in place to help facilitate and monitor any energy efficiency upgrades undertaken. The first step in documenting energy efficiency upgrade opportunities is the in-home energy evaluation, completed once the customer has been accepted into the program. The energy advisor completes the In-Home Energy Evaluation form to document related home information including heating fuel type, existing insulation measurements and the existing furnace or boiler heating system model and efficiency level. This is also the stage where a number of basic energy efficiency technologies are installed or left in the customer's home (such as a low flow showerhead or faucet aerator) and noted on the In-Home Energy Evaluation form. This form is returned to the Lower Income Energy Efficiency Program staff and further eligible efficiency upgrades are arranged with qualifying LIEEP contractors.

Insulation, Furnace and Boiler upgrades are tracked through the submission of forms by contractors titled "Authorization to Pay." The Authorization to Pay forms contain energy efficiency upgrade information including the installation date and a signed confirmation from the customer and contractor declaring the work has been completed as originally agreed upon and approved by the Lower Income Energy Efficiency Program. All furnace installations are inspected as per provincial regulations. Post-retrofit inspections are completed in approximately 20% of participating homes to verify measurements and that work was completed to LIEEP standards.

All upgrades are tracked by customer. Energy savings for insulation, furnace, boiler or basic energy efficiency measures installed in the home are based upon engineering estimates.

CAC/CENTRA II-78

f) State the identity of the personnel conducting the savings evaluations, including their degree of independence from the Company (e.g., employees, contractors, PUB-appointed).

ANSWER:

All program evaluations are performed by staff in the Planning, Evaluation and Research Department reporting directly to the Vice-President, Customer Care & Energy Conservation. All staff are employees of Manitoba Hydro.

JEMLP/CENTRA II-1

a) To clarify the question previously asked in IR question IR -1-7, Just Energy would like to know why Centra does not split out the monthly commodity charge for the base rate and the rider separately on the Centra invoice. That is, similar to the manner the individual components are reported on the Schedule of Sales and Transportation Service Rates published and filed with the Public Utilities Board each quarter.

b) Please explain the response in detail.

c) What would be required to show the base rate and the rider on separate lines on the invoice?

ANSWER:

Centra does not support separating the Primary Gas charge into a separate base rate and rate rider to be presented on the bill, as it is concerned that an additional unbundling of rates may exacerbate customer misunderstanding and confusion about the natural gas charges on the bill without providing any informational value to customers in unbundling the Primary Gas rate.