IN THE MATTER OF:

CENTRA GAS MANITOBA INC.
2013/14
GENERAL RATE APPLICATION

HEARING BEFORE
THE PUBLIC UTILITIES BOARD

Selected Hearing Documents

Volume 2 of 2

Fillmore Riley LLP
Robert F. Peters
Counsel to The Public Utilities Board
June 13, 2013

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40.

THE PUBLIC UTILITIES BOARD OF MANITOBA

IN THE MATTER OF: *The Public Utilities Board Act* (Manitoba); and

IN THE MATTER OF: An Application by Centra Gas Manitoba Inc. for an Order of the Public Utilities Board Approving Rates for the Sale of Supplemental Gas and for the Transportation and Distribution of Gas.

TO: The Executive Director of the
Public Utilities Board of Manitoba
Winnipeg, Manitoba

APPLICATION

Centra Gas Manitoba Inc. ("Centra") hereby applies to the Public Utilities Board of Manitoba ("PUB" or "Board") for an Order pursuant to *The Public Utilities Board Act*, for the following:

a) Approval of an approximate 2.0% general revenue increase effective August 1, 2013, sufficient to generate additional revenue of $6 million and projected net income of $5 million in 2013/14;

b) Approval of adjustments to rates to reflect changes in forecast non-Primary Gas costs, to be effective August 1, 2013;

c) Approval of Supplemental Gas, Transportation (to Centra), Distribution (to Customers) Sales and Transportation rates, Basic Monthly Charges, the Primary Gas Overhead rate and the Fixed Rate Primary Gas Service ("FRPGS") Program Cost Rate, effective August 1, 2013.

d) Final approval of gas costs for the period of November 1, 2010 to October 31, 2012;

e) Final approval of the disposition through rate riders of the various non-Primary Gas Purchased Gas Variance Accounts ("PGVA"), and other gas cost deferral account balances as at October 31, 2012;

f) Final approval of Primary Gas, Supplemental Gas, Transportation (to Centra), Distribution (to Customers) sales rates, and Basic Monthly Charges, effective May 1, 2011, which were approved on an interim basis in Order 66/11;

g) Final approval of Primary Gas, Supplemental Gas, Transportation (to Centra) and Distribution (to Customers) sales rates, effective May 1, 2012, reflecting the removal of non-Primary Gas rate riders, which were approved on an interim basis in Order 54/12;

h) Approval to change the rate setting formula for FRPGS to self-insure the volumetric and market price risk for each subsequent offering;

i) Approval to vary Directive 8 of Order 95/00, eliminating the requirement for Centra to submit a feasibility test to the Board for approval prior to commencement and construction of future expansions greater than 500 metres in the Rural Municipalities of Woodlands and Bifrost;

j) Final approval of interim Orders 106/10, 20/11, 96/11, 150/11, 7/12, 89/12, and 137/12 related to the approval of interim Primary Gas Sales Rates effective November 1, 2010, February 1, 2011, August 1, 2011, November 1, 2011, February 1, 2012, August 1, 2012, and November 1, 2012, respectively. Centra is also requesting final approval of any further interim ex-parte Orders related to the approval of Primary Gas Rates issued by the PUB prior to the conclusion of the hearing of this Application;

k) Final approval of interim Orders 80/11, 89/11, 101/11, 132/11, 51/12, 61/12, 67/12, 70/12, 85/12, 94/12, and 131/12 related to the approval of new franchise agreements and financial feasibility tests for the expansion of natural gas to the Rural Municipality ("RM") of Thompson & the RM of Roland, the RM of Portage la Prairie, the RM of Rockwood, the RM of Ste. Anne, the RM of Rosedale, the RM of Whitewater, the RM of Portage la Prairie, the RMs of South Norfolk & Grey, the RM of Ste. Anne, the RMs of Bifrost and Woodlands, and the RM of Woodworth, respectively. Centra is also requesting final approval of any further interim ex-parte Orders related to franchise applications issued by the PUB prior to the conclusion of the hearing of this Application;

l) Approval of changes to the Terms & Conditions of Service, as will be discussed in Volume II of the Application, including updated Activity Rates for chargeable services, changes to Centra's Customer Equipment Problem Program for Small General Service customers, and the introduction of new charges to recover costs related to third party damages to utility plant, to take effect upon Order of the Board; and,

m) Final approval of any interim rate Orders issued by the PUB subsequent to the filing of the Application and prior to conclusion of this proceeding.

Centra intends to file Volume II of the Application in February 2013, including materials on Centra's customer and volume forecast, rate base & rate of return, gas supply & costs, cost allocation, proposed rates and customer impacts, Fixed Rate Primary Gas Service, proposed changes to the Terms & Conditions of Service, and responses to a number of PUB directives.

Communication related to this Application should be addressed to Centra in the following fashion:

Centra Gas Manitoba Inc.
c/o: 22nd Floor, 360 Portage Avenue
Winnipeg, Manitoba
R3C 0G8

Attention:	Ms. M. D. Boyd
Telephone No.	204-360-3468
Fax No.	204-360-6147
E-Mail:	mboyd@hydro.mb.ca

DATED at Winnipeg, Manitoba this 25th day of January 2013.

CENTRA GAS MANITOBA INC.

A subsidiary of Manitoba Hydro

Per: M Boyd

Marla D. Boyd

41.

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

42.

2013/14 Updated Revenue Requirement ($000s)

		[A]	[B]	[C]	[D]
1	**Revenue Requirement**	**Last Approved 2010/11**	**2013/14 Test Year**	**Change from Last Approved**	**Change % from Last Approved**
2	Cost of Gas	331,442	183,202	(148,240)	-45%
3	Other Income	-2,026	-1,866	160	-8%
4	Operating & Administrative	60,343	68,800	8,457	14%
5	Depreciation & Amortization	27,367	30,091	2,724	10%
6	Furnace Replacement Program	3,800	3,800	-	-
7	Capital and Other Taxes	23,940	18,750	(5,190)	-22%
8	Finance Expense	19,105	17,296	(1,809)	-9%
9	Corporate Allocation	12,000	12,000	-	-
10	Net Income	2,505	4,821	2,316	92%
11	Revenue Requirement from Gas Rates	478,476	336,894	(141,582)	-30%
12	Less: Cost of Gas (line 2)	331,442	183,202		
13	Non-Gas Revenue Requirement	**147,034**	**153,692**	**6,658**	**5%**
14	Revenue on existing base rates		**331,149**		
15	Non-Gas Revenue Deficiency		(5,745)		
16	Increase in Non-Gas Revenue Requirement from Last Approved		6,658		
17	Difference between Non-Gas Revenue Deficiency and Non-Gas Revenue increase		913		

Source : PUB/Centra II-148 Updated for May 10, 2013 - Gas Cost Update

43.

GAS OPERATIONS (CGM12)
PROJECTED OPERATING STATEMENT
PUB/Centra I-10 (a) - CGM12 with the Board Approved Equity Ratio
(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	7	7	9	11	13	15	18
	319	319	363	358	356	357	360	362	365	368
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201
Gross Margin	143	151	151	155	154	156	159	161	164	167
Other	2	2	2	2	2	2	2	2	2	2
	145	153	153	156	156	158	161	163	166	169
EXPENSES										
Operating and Administrative	67	69	77	77	78	78	79	79	81	82
Finance Expense	18	17	21	22	23	25	25	26	27	28
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	153	155	158	161	165
Net Income	2	6	9	9	5	5	6	6	5	4
* Additional Revenue Requirement										
Percent Increase		2.00%	0.00%	0.00%	0.00%	0.50%	0.75%	0.50%	0.50%	0.75%
Cumulative Percent Increase		2.00%	2.00%	2.00%	2.00%	2.51%	3.28%	3.80%	4.31%	5.10%
Financial Ratios										
Equity Ratio (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

GAS OPERATIONS (CGM12)
PROJECTED BALANCE SHEET
PUB/Centra I-10 (a) - CGM12 with the Board Approved Equity Ratio
(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	290	330	340	360	380	390	400	420	410
Current and Other Liabilities	99	96	67	69	68	56	57	57	48	69
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)	(18)	(13)	(7)	(2)	4	9	13
	586	594	536	557	580	595	610	625	640	655

GAS OPERATIONS (CGM12)
PROJECTED CASH FLOW STATEMENT
PUB/Centra I-10 (a) - CGM12 with the Board Approved Equity Ratio
(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	392	390	391	394	397	399	403
Cash Paid to Suppliers and Employees	(291)	(335)	(347)	(347)	(348)	(347)	(348)	(349)	(352)	(354)
Interest Paid	(19)	(19)	(20)	(21)	(23)	(24)	(25)	(26)	(26)	(27)
	45	3	33	23	20	20	21	22	21	21
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	60	30	40	10	20	20	10	10	20	10
Retirement of Long-Term Debt	(63)	-	(35)	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-
	(3)	30	5	10	20	20	10	10	20	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)	5	(4)	(1)	7	(2)	(3)	7	(4)
Cash at Beginning of Year	(13)	(9)	(15)	(10)	(15)	(16)	(9)	(12)	(14)	(7)
Cash at End of Year	(9)	(15)	(10)	(15)	(16)	(9)	(12)	(14)	(7)	(11)

Financial Statements

Centra Gas Manitoba Inc.

March 31, 2012

ERNST & YOUNG

NOTE 1 SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation – The financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP) as set forth in Part V of the Canadian Institute of Chartered Accountants (CICA) Accounting Handbook, "Pre-Changeover Accounting Standards" and include the significant accounting policies described hereafter.

Rate-Regulated Accounting - The prices charged for the sale of natural gas within Manitoba are subject to review and approval by the Public Utilities Board of Manitoba (PUB). The rate-setting process is designed such that rates charged to gas customers recover all costs incurred in providing gas service to customers. As permitted under GAAP, the Corporation applies standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of GAAP. FASB Accounting Standards Codification Section 980 – Regulated Operations, represents the standard Centra Gas Manitoba Inc. (Centra) applies for rate-regulated accounting. These accounting policies differ from enterprises that do not operate in a rate-regulated environment. Such accounting policies allow for the deferral of certain costs or credits which will be recovered or refunded in future rates. These costs or credits would otherwise be included in the determination of net income in the year that the cost or credit is incurred. Centra refers to such deferred costs or credits as regulated assets (Note 7) or regulated liabilities (Note 11) which are generally comprised of the following:

- Power Smart programs - The costs of Centra's energy conservation programs, referred to as Power Smart, are deferred and amortized on a straight-line basis over a period of 10 years.

- Deferred taxes - As a result of its acquisition by Manitoba Hydro in 1999, Centra became non-taxable and, in so doing, incurred a non-recurring tax expense. This non-recurring tax expense has been deferred and is being amortized over a period of 30 years.

- Site restoration costs - Site restoration costs incurred are deferred and amortized on a straight-line basis over a period of 15 years.

- Regulatory costs - Costs associated with regulatory hearings are deferred and amortized on a straight-line basis over periods up to 5 years.

- Purchased gas variance accounts - Accounts are maintained to recover/refund differences between the actual cost of gas and the cost of gas incorporated into rates charged to customers as approved by the PUB. The difference between the recorded cost of natural gas and the actual cost of natural gas is carried as an account receivable/payable, and recovered or refunded in future rates.

NOTE 7 REGULATED ASSETS

	2012	2011
	millions of dollars	
Power Smart programs	**44**	39
Deferred taxes	**30**	33
Site restoration costs	**2**	2
Regulatory costs	**1**	1
	77	75

If Centra was not subject to rate regulation, the costs associated with the regulated assets would be charged to operations in the period that they were incurred and the net loss for 2012 would have increased by $2 million (2011 – net income decreased by $5 million).

In total, regulated assets of $10 million (2011 - $10 million) were amortized to operations during the period.

NOTE 8 INTANGIBLE ASSETS

	2012			2011		
	Cost	Accumulated amortization	Net	Cost	Accumulated amortization	Net
	millions of dollars			*millions of dollars*		
Computer application development	**7**	**3**	**4**	10	7	3
Land easements	**5**	**1**	**4**	5	1	4
	12	**4**	**8**	15	8	7

The additions to intangible assets for the year were $1 million (2011 - $1 million). In total, intangible assets of $2 million (2011 - $2 million) were amortized to operations during the period.

44.

GAS OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/Centra I-7 (c): CGM12 with IFRS Deferral to 2015/16 and Rate Regulated Accounting
(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	7	7	9	11	13	15	18
	319	319	363	358	356	357	360	362	365	368
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201
Gross Margin	143	151	151	155	154	156	159	161	164	167
Other	2	2	2	2	2	2	2	2	2	2
	145	153	153	156	156	158	161	163	166	169
EXPENSES										
Operating and Administrative	67	69	71	70	71	73	74	76	77	79
Finance Expense	18	17	19	20	22	23	24	25	26	27
Depreciation and Amortization	28	30	31	30	31	32	32	33	32	33
Capital and 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	2	6	1	6	1	(1)	(1)	(2)	(1)	(2)

* Additional Revenue Requirement										
Percent Increase		2.00%	0.00%	0.00%	0.00%	0.50%	0.75%	0.50%	0.50%	0.75%
Cumulative Percent Increase		2.00%	2.00%	2.00%	2.00%	2.51%	3.28%	3.80%	4.31%	5.10%

GAS OPERATIONS
PROJECTED BALANCE SHEET
PUB/Centra I-7 (c): CGM12 with IFRS Deferral to 2015/16 and Rate Regulated Accounting
(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	704	732	764	786	809	832	857	883
Accumulated Depreciation	(232)	(240)	(250)	(255)	(262)	(271)	(281)	(291)	(301)	(312)
Net Plant in Service	424	439	454	477	502	515	528	541	556	571
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	76	73	69	63	57	49	43	37
	586	594	607	625	645	653	662	669	678	687
LIABILITIES AND EQUITY										
Long-Term Debt	295	290	330	340	360	380	390	400	410	410
Current and Other Liabilities	99	96	68	70	69	58	58	59	60	71
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	43	49	50	49	48	46	45	43
	586	594	607	625	645	653	662	669	678	687

April 2013

Exposure Draft

Snapshot: Regulatory Deferral Accounts

This snapshot introduces the Exposure Draft *Regulatory Deferral Accounts*, which has been published for public comment by the International Accounting Standards Board (IASB). It provides an overview of the main proposals that were developed by the IASB.

Project objectives:

The long-term objective of the Rate-regulated Activities project is to develop a Discussion Paper to consider whether rate regulation creates assets or liabilities in addition to those already recognised in accordance with IFRS for non-rate-regulated activities. If so, the project will also consider how such assets and liabilities should be accounted for and whether (and how) IFRS should be amended.

The objective of the proposals in the Exposure Draft *Regulatory Deferral Accounts* is to enhance the comparability of financial reporting by reducing barriers to the adoption of IFRS by entities with rate-regulated activities until guidance is developed through the comprehensive Rate-regulated Activities project. If the proposals are accepted, the IASB will issue an interim Standard.

Project stage:

The IASB published, in March 2013, the Request for Information *Rate Regulation*. The responses to that consultation will be used as part of the research for the development of the Discussion Paper. This research phase is being carried out alongside the development of the proposed interim Standard.

Comment deadline:

The Exposure Draft is open for public comment until **4 September 2013**.

Next steps:

The IASB aims to issue the Discussion Paper in the fourth quarter of 2013.

Comment letters received during the consultation process for each phase of the project will be published on the IASB's website. The IASB will discuss the feedback received and will redeliberate on the proposals for the interim Standard in public IASB meetings in the fourth quarter of 2013.

IFRS®

Why is the IASB undertaking the project?

Rate regulation is a restriction on the setting of prices that can be charged to customers for services or products. In many jurisdictions, the charges that particular entities can demand from their customers are set by regulatory bodies or governments. Typically, such an entity (a 'rate-regulated entity') has a monopoly or a dominant market position that gives it excessive market power.

In 2009, the IASB published for public comment an Exposure Draft *Rate-regulated Activities*, which focused on a particular type of rate-regulatory scheme (a 'cost-of-service' scheme). After reviewing the responses to that Exposure Draft, the IASB decided that it could not resolve, in a timely manner, the complex, fundamental issues involved and suspended the project.

As a result of the views received from its three-yearly agenda consultation, the IASB, in September 2012, started a revised, comprehensive Rate-regulated Activities project. The aim of this comprehensive project is to develop a Discussion Paper that will identify and more clearly articulate:

(a) the common features of rate regulation;

(b) whether these common features create economic resources for, or claims against, a rate-regulated entity that should be recognised in IFRS financial statements; and

(c) the information about the consequences of rate regulation that would be most useful for users of IFRS financial statements.

Why is the IASB proposing an interim Standard?

The requirements of some national accounting standard-setting bodies permit or require entities that are subject to certain types of rate regulation to capitalise and defer expenditures (or income) that would otherwise be recognised as expenses (or income) in the statement of profit or loss and other comprehensive income by non-rate-regulated entities. These amounts are often referred to as 'regulatory deferral' (or 'variance') accounts.

There is currently no Standard in IFRS that specifically addresses the accounting for rate-regulated activities. The increased use of IFRS has increased the pressure on the IASB to address whether regulatory deferral account balances should be recognised in IFRS financial statements. The pressure has come mainly (but not exclusively) from jurisdictions that have not yet adopted IFRS and that currently recognise such regulatory items in accordance with their current GAAP.
The complex issues that are being addressed in the comprehensive Rate-regulated Activities project will take time to resolve.

In addition, the *Conceptual Framework* is currently being reviewed and updated, which will influence the outcome of the Rate-regulated Activities project.

The IASB recognises that discontinuing the recognition of regulatory deferral account balances before the completion of the comprehensive Rate-regulated Activities project could be a significant barrier to the adoption of IFRS for those entities for which regulatory deferral account balances represent a significant proportion of net assets. The IASB is, therefore, proposing to allow those entities that currently recognise regulatory deferral account balances in accordance with their current GAAP to continue to do so when making the transition to IFRS.

Why are the proposals restricted to first-time adopters of IFRS?

By publishing this Exposure Draft, the IASB is in no way anticipating the outcome of the comprehensive Rate-regulated Activities project. Although the IASB has developed these proposals with the aim of enhancing the comparability of financial reporting by reducing barriers to the adoption of IFRS by entities with rate-regulated activities, the IASB wishes to limit the impact of the proposals until the more fundamental issues about accounting for rate-regulated activities is completed through the comprehensive project.

One of the fundamental issues to address is whether regulatory deferral account balances meet the definitions of assets and liabilities in the *Conceptual Framework*. Consequently, the term 'regulatory deferral account balances' has been chosen as a neutral descriptor for these items instead of describing them as 'regulatory assets' or 'regulatory liabilities'.

What types of rate-regulation are in the scope of the proposed interim Standard?

A number of rate-regulatory methodologies exist and their application can vary by rate regulator, the entity being regulated and the particular circumstances. The previous Exposure Draft focused on a specifically defined rate-regulatory scheme (a 'cost-of-service' scheme). The current proposals do not have such a narrow focus. They do, however, still intend to restrict the types of schemes captured by the proposals to those that have an identifiable causal effect between the costs (and income) that are expected to be recognised in the financial statements of the rate-regulated entity and the basis of the rate calculation.

Consequently, the proposals address only those rate-regulated activities that meet the following two criteria:

(a) an authorised body is empowered to establish rates that bind customers; and

(b) the price established by the regulation (the 'regulated rate') is designed to recover the costs that are specific to the entity and for which the regulated rate is intended to provide recovery.

What is the IASB proposing?

The Exposure Draft proposes to:

(a) permit an entity that adopts IFRS to continue to use its previous GAAP accounting policies, as accepted in their local jurisdiction, for the recognition, measurement and impairment of regulatory deferral account balances;

(b) require the entity to present regulatory deferral account balances as separate line items in the statement of financial position and to present movements in those account balances as a separate line item in the statement of profit or loss and other comprehensive income; and

(c) require specific disclosures to identify clearly the nature of, and risks associated with, the rate regulation that has resulted in the recognition of regulatory deferral account balances in accordance with the proposals.

Some IASB members think that the separate presentation is essential until the consideration of the more fundamental issues about accounting for rate-regulated activities is completed through the comprehensive project.

Transition

The IASB does not propose any explicit relief from full retrospective application of the proposed interim Standard because existing recognition and measurement policies will continue. First-time adopters of IFRS can use the deemed cost exemption for property, plant and equipment and intangible assets that is already available in IFRS 1 *First-time Adoption of International Financial Reporting Standards* that allows adopters to use their previous GAAP carrying amounts at the date of transition to IFRS.

Consequently, first-time adopters will only need to change their presentation policies for property, plant and equipment and intangible assets to isolate the regulatory deferral account amounts on a prospective basis from the date of transition to IFRS. This will result in these items being presented on the same basis as those of entities that are not eligible for, or choose not to apply, this proposed interim relief.

How can I comment on the Exposure Draft?

The Exposure Draft includes questions related to the IASB's proposals. Please send us your comments on any or all of those questions on or before 4 September 2013.

To view the Exposure Draft and to submit your comments, visit the 'Open for Comment' section on www.ifrs.org

Important information

This Snapshot has been compiled by the staff of the IFRS Foundation for the convenience of interested parties. The views expressed within this document are those of the staff who prepared the document. They do not purport to represent the views of the IASB and should not be considered as authoritative. Comments made in relation to the application of IFRS do not purport to be acceptable or unacceptable application of IFRS.

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Debt: Equity Ratio

Centra indicated that with respect to net income and the development of sufficient retained earnings from natural gas distribution operations to provide for a prudent foundation, MH sought only to gradually bring Centra's debt: equity ratio, now calculated in accordance with MH's perspective at 86:14, to 75:25.

Firstly, the Board again rejects the premise that Centra's debt: equity ratio for regulatory purposes be calculated ignoring its share capital. The Board continues to agree with CAC/MSOS that Centra's debt: equity ratio is to be considered on a standalone basis.

The Board agrees with Centra that there are alternate and perhaps acceptable ways of calculating debt: equity ratios, however the Board continues to find that calculating Centra's debt: equity ratio on a standalone basis is the most appropriate approach for rate setting. In short, the Board does not accept that a different target other than one based on a standalone view of Centra's balance sheet should be utilized.

As to the debt:equity ratio to be selected as the target on the standalone basis, the Board accepts Mr. Matwichuk's advice and finds that given Centra's borrowings are guaranteed by the Province, with the fee for the guarantee allowed in costs for rate setting, a 70:30 ratio is adequate, rather than the 60:40 model that would be acceptable if there were no provincial guarantee.

The Board notes that Centra's debt: equity ratio already exceeds the 70:30 standalone test, and that this reinforces the Board's determination to hold Centra's allowable annual Net Income to $3 million, given the Corporate Allocation remains at $12 million. The Board also notes that contributions from customers, unlike the case with MH, is not included as equity in Centra's calculation of the standalone debt:equity ratio. If it were, Centra would be well in excess of the target.

Corporate Allocation

The Board notes that Centra again confirmed its understanding that MH's acquisition of Centra is not to result in higher rates for Centra customers than would otherwise have been the case under Centra's management by its former private owner. From the date of acquisition in 1999, the only cost to Centra arising out of its acquisition by MH has been the Corporate Allocation. MH has not taken any dividends out of Centra's retained earnings and in this hearing MH's Chief Financial Officer reiterated that MH had no intention to withdraw funds from Centra by way of dividend.

In the Board's view, an ability to offset the annual Corporate Allocation with "savings" would facilitate the assurance that the "no harm" pledge is being kept. At this hearing, Centra confirmed that annual savings from synergies and avoided costs, the latter being costs previously incurred under private ownership that are no longer incurred, were sufficient to ensure the continuation of the $12 million Corporate Allocation charge.

This is before considering:

1. the potential for further synergy savings (single-bill initiative, four party trench, etc.);
2. non-monetary advantages to Centra customers arising from MH's ownership; and
3. further tax savings once the one-time tax liability resulting from the acquisition is fully amortized.

The Board considers that on-going general price inflation, decreased average volume of gas usage per residence, a significant and sustained growth in MH's consolidated O&A, additions and improvements to Centra services to customers, and growth in the customer base including expansion outside of Winnipeg all would have been expected to increase O&A costs per customer by more than has been the case.

Centra and CAC/MSOS provided the Board with alternative analysis of what the costs would be for Centra absent it being acquired in 1999. The Board finds both analyses plausible and equally unable to be proven or disproven.

As stated in Order 135/05

> *"...the Board believes that there is no merit in pursuing the elusive issue of estimating realized synergistic benefits and projecting what would have been Centra's operating costs if the former private ownership had continued in future applications.*
>
> *The passage of time and the continuing full integration of the gas and electric operations make it increasingly difficult if not impossible to track and isolate synergistic benefits from normal productivity gains and other factors."*

The Board does not find such retrospective analysis to be helpful and will not require them to be presented at future applications.

When considering the question as to whether Centra's customers are better off, or at least have not been harmed by the acquisition, the Board accepts that benefits not easily measured in quantifiable terms should be considered. Non-monetary benefits arising out of the acquisition and integration, as reported by Centra at the 2005 GRA hearing, included:

a) reduced duplication of functions with respect to such matters as line locating
b) enhanced system integrity and reliability (formalized evaluation of "at risk" facilities and networks, increased pipeline assessment activities to evaluate coating and corrosion issues)
c) energy bills for electricity and natural gas within one envelope; soon one bill
d) web information and electronic newsletter services provide electricity and natural gas customers a single site for a range of useful information with respect to heating efficiency measures and energy source selection
e) automated customer notification system for interruptible customers
f) the availability of internet banking and e-business resources now available to gas customers provide greater access to alternative technologies for payment and service transactions

g) an integrated voice response system to shorten wait time for customer telephone inquiries
h) expanded hours of operation and increased staffing in the customer service area
i) increasingly integrated Power Smart programs
j) environmental stewardship has been enhanced by the integration
k) extension of professional services
l) enhanced staff and service depth

There may be other "non-monetary" benefits that have arisen from the acquisition and integration, and these include:

1. decision-making centered in Manitoba, with senior officials located in Manitoba;
2. increased attention being paid to public interest issues – no longer driven by financial objectives (approach to low-income customers, demand side management, etc.); and
3. improved borrowing power.

Allowable Returns to MH

With respect to MH's perspective, the Board has long accepted that the costs to be recovered from Centra by MH should include a share of the costs associated with the acquisition. The Board reminds MH and Centra that this sharing will be satisfactory and fair only as long as those costs do not exceed the lesser of what is required for MH's full recovery of acquisition costs or $12 million per year. As well, the final test to be applied is that any combination of net income and charges to Centra by MH do not result in higher rates for Centra customers than would have been the case under private ownership.

The Board understands MH's rationale for the Corporate Allocations. That said, the Board notes that the first priority is the position of Centra customers, and any risk of under recovery must fall to MH's customers, regardless of the fact that all of Centra's customers are included within MH's customer list for electricity.

The "no harm" principle is of a paramount importance with respect to the dealings between Centra and its parent, MH. For the principle of "no harm" to be honoured, Centra and MH will have to be/continue to be successful in the efforts to achieve and maintain synergy savings and higher productivity. The Board anticipates that ensuring "no harm" to electricity and natural gas customers will be less difficult in time, particularly upon the eventual full amortization of the one-time income tax payment and integration costs.

The Board concurs with MH's decision not to take dividends from Centra. As long as dividends are not declared and taken from Centra's retained earnings, and the annual Corporate Allocation remains at the current level, the Board will have a level of assurance that Centra's customers have not been "harmed" by MH's acquisition of Centra. The other major issue to be considered in this regard is net income, which is discussed subsequently.

The Board established in Orders 103/05 and 135/05 that the Corporate Allocation combined with Board allowed net income is not to exceed the return previously provided to Centra's private owner prior to MH's acquisition which ranged from $14 to $16 million, and allowed the Corporate Allocation of $12 million and annual Net Income of $3 million.

The Board had also stated in Order 103/05 the return to MH as determined under *Rate Base Rate of Return* is to be the absolute limit for shareholder returns. That return may take the form of an annual Corporate Allocation by MH against Centra and/or Centra's annual net income result. The Board further clarifies its position relative to testing the reasonableness of the net income limit. In assessing the reasonableness the Board also considers the no harm principle to be paramount and that a total return of $14-16 million contemplated at the time of MH's acquisition of Centra currently remains appropriate to ensure neither Centra nor MH customers are negatively impacted from the transaction.

The Board continues to accept the annual Corporate Allocation of $12 million, the premise that synergies have been sufficient to uphold the “no harm” principle, and that, as now to be reviewed, an annual Net Income of $3 million does not represent an unwarranted return on investment for MH.

Capital Expenditures

With the exception of the AMI implementation expenditures, (Centra has yet filed the business plan for AMI as directed by the Board in a prior Order), Centra’s capital expenditures on plant and equipment are approved for inclusion in Rate Base.

Centra should be ever mindful of the decreasing load that has occurred and may lie ahead before undertaking expenditures related to capacity increases. Gas usage in Manitoba has fallen and is expected to further decrease, so it is incumbent on Centra to ensure that the forecasts of load growth and system capacity are reconciled, and that expenditures on capacity increases are prudently undertaken.

A trend of reducing average consumption per customer is well established, and as DSM programs ramp up, the trend of reduced gas usage should accelerate. Centra may eventually experience significant load (consumption) reductions, and this may result in materially increased unused capacity in its existing transmission and distribution network, and higher non-gas rates.

On another front, Centra has expended approximately $220 million on capital expenditures since its acquisition by MH in 1999, yet the Board continues to hold Centra to an allowable aggregate return of $15 million ($3 million for Net Income, and $12 million representing the annual

At that time, PUB will expect Centra to provide an opinion on the sufficiency of its then-level of retained earnings, presumably a time in which the implications of IFRS will be known.

Corporate Allocation & Net Income

MH acquired Centra in 1999 for $253.8 million, funding the acquisition by debt, purchasing Centra's business and assets, assuming its liabilities, and recognizing goodwill, asset write-ups, and acquisition and integration costs. In Order 118/03, the Board discussed the source of funds available to MH from Centra to fund the acquisition, and stated:

> *The Board believes the no-harm principle is paramount, and that both Centra and MH ratepayers should, to the extent possible, be held harmless as a result of the decision by MH to acquire Centra. The Board also recognizes that since MH initiated the transaction, it should bear some risk relative to the transaction, particularly since MH's size relative to Centra makes it better able to manage any negative cost implications resulting from the acquisition.*

As articulated in that Order, prior to MH's acquisition, and during the period under the former private ownership, Centra produced average annual after tax profits of between $14 and $16 million. At that time, it was expected, and expectation supported by subsequent PUB Orders, that after taking into account the same level of return allowed to the former private owner and the expected savings to arise out of operational synergies, MH would acquire Centra without any negative rate implications for either the customers of Centra or MH.

At the 2005 GRA, Centra confirmed that approximately $19 million was required annually to amortize MH's 'costs' arising out of the acquisition, and that Centra's share of those costs was to be $12 million, with the other $7 million to be borne by MH.

Also at the 2005 GRA, a detailed assessment of whether Centra's customers had been harmed by MH's acquisition of ownership was undertaken. In part, this included an assessment of the challenged Centra's ability to fund its ongoing operations, PUB would act to improve Centra's situation. Centra is a monopoly, and regulated by a regulator that considers the public interest to include both the well-being of the utility's customers and the financial condition of the utility itself.

At the last GRA, based on the Board's direction in Order 99/07 limiting normal weather annual Net Income to $3 million, retained earnings were forecasted to reach approximately $26 million by 2008/09. Centra's actual Net Income for 2008/09 was estimated to be $9.1 million, $6.1 million higher than would have been expected given normal weather. And, in the previous year, Centra earned $5.9 million in Net Income, again more than the $3 million provided for in rates from the previous GRA, and the excess again primarily the result of colder than normal weather.

Centra forecasts $36.4 million in retained earnings as of March 31, 2009, $10 million more than was forecast at the previous GRA proceeding. Centra forecasts $42.2 million in retained earnings as of March 31, 2011, well above the $32 million if operations had and were carried on in normal weather conditions from April 1, 2007.

The Board regulates Net Income on a weather-normal basis and is not concerned that Centra exceeded its approved Net Income in 2007/08 and 2008/09. Centra's Net Income has been negative in previous years due to the weather, and the Board accepts this scenario. Year-to-year fluctuations in Net Income caused by weather should not affect the timing and magnitude of GRAs.

Regardless of PUB's intention to set rates in accordance with accounting policies that may or may not be in accordance with IFRS, the Board will, as it does at each GRA proceeding, review the adequacy of Centra's retained earnings at the next GRA.

Centra acknowledged that it has not undertaken a specific risk analysis to determine what would represent an appropriate level of retained earnings for Centra, noting that it was premature to undertake such a study until the financial implications of IFRS are known.

Board Findings - Debt to Equity Ratio

In Centra's prior GRA, the subject of Order 99/07, the Board concluded that a debt to equity ratio of 70:30 for the Utility was sufficient given Centra's subsidiary status (MH being the parent, with its consolidated debt guaranteed by the Province).

Centra's specific debt to equity ratio is not a material issue as long as Centra's financial position does not represent a risk to MH's overall capital position and borrowing ability.

The 'excess' net income results of the last two fiscal periods due to weather have improved Centra's financial position, and with a debt to equity ratio of 69:31 Centra does not pose a drag on either MH's capital position or borrowing opportunities.

While the approaching adoption of IFRS will possibly have negative implications for Centra's audited balance sheet, any changes to asset or liability balances brought about by IFRS, unless reflected in the setting of rates which provide the necessary cash flow for the Utility, will not impact on its operational situation.

PUB will continue to set Centra's rates, and intends to ensure that rates are adequate to generate the required cash flow the Utility needs to operate effectively. While PUB will review the debt to equity position and level of retained earnings of Centra post-adoption of IFRS, changes wrought by IFRS may or may not affect rate setting.

Considering current accounting standards and practices employed by Centra and recognized by PUB, Centra's capital structure is adequate to meet known risks. If circumstances arose that challenged Centra's ability to fund its ongoing operations, PUB would act to improve Centra's situation. Centra is a monopoly, and regulated by a regulator that considers the public interest to include both the well-being of the utility's customers and the financial condition of the utility itself.

At the last GRA, based on the Board's direction in Order 99/07 limiting normal weather annual Net Income to $3 million, retained earnings were forecasted to reach approximately $26 million by 2008/09. Centra's actual Net Income for 2008/09 was estimated to be $9.1 million, $6.1 million higher than would have been expected given normal weather. And, in the previous year, Centra earned $5.9 million in Net Income, again more than the $3 million provided for in rates from the previous GRA, and the excess again primarily the result of colder than normal weather.

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The Board regulates Net Income on a weather-normal basis and is not concerned that Centra exceeded its approved Net Income in 2007/08 and 2008/09. Centra's Net Income has been negative in previous years due to the weather, and the Board accepts this scenario. Year-to-year fluctuations in Net Income caused by weather should not affect the timing and magnitude of GRAs.

Regardless of PUB's intention to set rates in accordance with accounting policies that may or may not be in accordance with IFRS, the Board will, as it does at each GRA proceeding, review the adequacy of Centra's retained earnings at the next GRA.

PUB/CENTRA I-16

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Reference Tab 5 Page 2 of 30 Schedule 5.1.0**

Order 128/09

a) **Please explain why Centra has applied for net income in excess of the $3 million previously approved by the Board in Order 128/09 as well as in previous Orders.**

ANSWER:

Centra has been regulated on the basis that it would be allowed to earn a $3 million dollar net income on an annual basis since 2003/04. However, Centra's retained earnings have essentially remained flat over that period of time and are $34 million at the end of 2011/12 versus $35 million at the end of 2002/03. The retained earnings have remained flat despite the growth in In-service Plant from $503 to $637 million during that time.

Centra's last general rate increase was 0.8% for 2010/11 flowing from Order 128/09. This is the only general rate increase that Centra obtained for the four year period between 2009/10 and 2012/13.

At the time that Centra filed the 2013/14 GRA, it was projected based on CGM12 that it would be required to write-off rate-regulated assets of approximately $77 million to retained earnings upon adoption of IFRS in 2014/15 which would result in a retained earnings deficit.

Since the filing of the 2013/14 GRA, the adoption of IFRS has been deferred by an additional year to 2015/16 and the IASB has indicated it plans to issue a draft standard to continue to permit the use of rate-regulated accounting on an interim basis for first time-adopters of IFRS. However, there is still uncertainty as to the final outcome of the IASB's project on rate-regulated activities and whether or not rate-regulated accounting will continue to be permitted over the long-term.

Even under the scenario which assumes the deferral of IFRS to 2015/16, the continuation of rate-regulated accounting until the end of the forecast period in CGM12, the 2.0% general rate increase and future indicative rate increases assumed in CGM12 (please see Centra's response to PUB/Centra I-7(c)), retained earnings are only forecast to grow marginally to $43 million by 2021/22 despite further projected growth in In-service plant to $883 million during that period of time.

There are also other financial risks facing Centra such as the need to maintain gas infrastructure in a safe and reliable manner exerting pressure on operating and maintenance costs, and lower revenues due to declining sales volumes associated with continuing conservation efforts.

Taking all of the above-noted factors into consideration, Centra is of the view that the modest general rate increase of 2.0% that is requested in the 2013/14 GRA which produces a projected net income of $5 million in 2013/14 remains reasonable. The requested rate increase is necessary to maintain an adequate financial structure and retained earnings and to promote long-term rate stability for gas customers.

PUB/CENTRA I-16

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Reference Tab 5 Page 2 of 30 Schedule 5.1.0**

Order 128/09

d) **Please file an IFF scenario reflecting $3 million in net income in 2013/14 and beyond, as well as the continuation of rate-regulated accounting under IFRS. Indicate the level of rate increases required to maintain the level of net income.**

ANSWER:

Please see the schedule below. Please note that the 1.19% rate increase for 2013/14 indicated in this IFF scenario assumes that the rate increase is implemented on May 1, 2013.

GAS OPERATIONS (CGM12)
PROJECTED OPERATING STATEMENT
1Yr IFRS Def, Rate Regulated Acc, $3M Net Income
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
REVENUES											
General Consumers											
at approved rates	319	312	356	351	349	348	349	349	350	350	351
additional revenue requirement*	0	4	9	4	9	13	15	17	19	21	23
	319	316	365	355	358	361	363	367	368	372	374
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201	201
Gross Margin	143	148	153	152	156	160	162	166	167	171	173
Other	2	2	2	2	2	2	2	2	2	2	2
	145	150	155	154	158	162	164	168	169	173	175
EXPENSES											
Operating and Administrative	67	69	71	70	71	73	74	76	77	79	81
Finance Expense	18	17	19	20	22	23	23	24	25	26	26
Depreciation and Amortization	28	30	31	30	31	32	32	33	32	33	32
Capital and Other Taxes	18	19	19	19	19	20	20	20	20	20	21
Corporate Allocation	12	12	12	12	12	12	12	12	12	12	12
	143	147	152	151	155	159	161	165	166	170	172
Net Income	2	3	3	3	3	3	3	3	3	3	3
* Additional Revenue Requirement											
Percent Increase		1.19%	1.48%	-1.49%	1.50%	1.03%	0.47%	0.82%	0.25%	0.82%	0.28%
Cumulative Percent Increase		1.19%	2.69%	1.16%	2.68%	3.74%	4.24%	5.09%	5.35%	6.22%	6.51%

GAS OPERATIONS (CGM12)
PROJECTED BALANCE SHEET
1Yr IFRS Def, Rate Regulated Acc, $3M Net Income
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
ASSETS											
Plant in Service	656	679	704	732	764	786	809	832	857	883	909
Accumulated Depreciation	(232)	(240)	(250)	(255)	(262)	(271)	(281)	(291)	(301)	(312)	(324)
Net Plant in Service	424	439	454	477	502	515	528	541	556	571	585
Construction in Progress	2	2	2	2	2	4	6	8	8	8	9
Current and Other Assets	73	68	68	68	68	68	68	68	68	68	68
Goodwill and Intangible Assets	9	8	6	5	4	3	3	3	3	3	3
Regulated Assets	79	78	76	73	69	63	57	49	43	37	32
	586	594	607	625	645	653	662	669	678	687	697
LIABILITIES AND EQUITY											
Long-Term Debt	295	300	330	350	370	370	380	390	400	390	420
Current and Other Liabilities	99	89	68	63	61	66	62	57	54	71	49
Contributions in Aid of Construction	35	45	45	45	44	45	44	43	42	41	41
Share Capital	121	121	121	121	121	121	121	121	121	121	121
Retained Earnings	36	39	42	46	49	52	55	58	61	64	67
	586	594	607	625	645	653	662	669	678	687	697

GAS OPERATIONS (CGM12)
PROJECTED CASH FLOW STATEMENT
1Yr IFRS Def, Rate Regulated Acc, $3M Net Income
(In Millions of Dollars)

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
OPERATING ACTIVITIES											
Cash Receipts from Customers	355	354	403	389	392	396	398	401	403	407	409
Cash Paid to Suppliers and Employees	(291)	(335)	(341)	(340)	(340)	(342)	(344)	(347)	(349)	(352)	(354)
Interest Paid	(19)	(19)	(20)	(21)	(23)	(24)	(24)	(25)	(26)	(26)	(27)
	45	0	41	28	29	29	29	30	29	29	29
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	60	40	30	20	20	-	10	10	10	10	30
Retirement of Long-Term Debt	(63)	-	(35)	-	-	-	-	-	-	-	(20)
Other	-	-	-	-	-	-	-	-	-	-	-
	(3)	40	(5)	20	20	-	10	10	10	10	10
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(37)	(39)	(39)	(45)	(48)	(37)	(37)	(37)	(37)	(37)	(39)
Other	(0)	(1)	(0)	(0)	(0)	(1)	(1)	(1)	(0)	(0)	(0)
	(37)	(39)	(39)	(45)	(48)	(38)	(38)	(37)	(38)	(38)	(39)
Net Increase (Decrease) in Cash	5	1	(3)	3	1	(9)	2	3	2	2	0
Cash at Beginning of Year	(13)	(9)	(8)	(11)	(8)	(7)	(16)	(14)	(11)	(10)	(8)
Cash at End of Year	(9)	(8)	(11)	(8)	(7)	(16)	(14)	(11)	(10)	(8)	(8)

Centra Gas Manitoba Inc 2013/14 GRA
Equity (Year End) Continuity ($000)

Line		2003/04 Actual	2004/05 Actual	2005/06 Actual	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
1												
2	Opening Retained Earnings	34,967	27,054	25,428	20,053	21,127	27,383	34,394	33,443	40,052	34,301	35,863
3	Net Income (Loss)	(7,912)	(1,626)	(5,375)	1,074	5,899	8,596	(950)	6,609	(5,751)	1,562	4,821
4	Dividend											
5	Ending Retained Earnings	27,055	25,428	20,053	21,127	27,026	35,979	33,444	40,052	34,301	35,863	40,684
6	Retained Earnings Adjustment (1)(2)					356	(1,585)					
7	Share Capital	121,250	121,250	121,250	121,250	121,250	121,250	121,250	121,250	121,250	121,250	121,250
8	Total Equity	148,305	146,678	141,303	142,377	148,632	155,644	154,694	161,302	155,551	157,113	161,934

9 **Impact of Weather on Retained Earnings**

Line		2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	Total 2004- 2012
10	Actual Net Income	(7,912)	(1,626)	(5,375)	1,074	5,899	8,596	(950)	6,609	(5,751)	564
11	Weather Normal Net Income	(6,828)	(4,214)	2,189	2,877	957	1,388	1,901	6,553	2,480	7,303
12	Difference	(1,084)	2,588	(7,564)	(1,803)	4,942	7,208	(2,851)	56	(8,231)	(6,739)
13	Weather Normalized Retained Earnings 2011/12										**$ 41,040**

Notes:

14 (1) Adjustment of $356 for the implementation of the financial instrument standards.
(2) Adjustment of $1,585 for the implementation of the goodwill and intangible standard. Represents cumulative reduction earnings related to the write-off of general advertising and promotion costs
15 related to Centra's Power Smart programs.

16 **References:**
17 PUB/Centra 12 (a) Attachment, PUB/Centra 78 (b) 2007/08 & 2008/09 GRA
18 PUB/Centra 13 (f) Attachment, PUB/Centra 77 (b) 2008/09 & 2009/10 GRA
19 PUB/Centra I -13 (a)& PUB/Centra I-86 (b) 2013/14 GRA

Capital Structure ($000's)
Centra Gas Manitoba Inc. 2013/14 GRA

		2002/03 Actual	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Test
1	**Capital Structure**												
2	Long Term Debt (13 month average)	241,894	256,177	253,117	250,057	243,362	240,261	238,001	253,260	297,671	297,671	296,244	295,000
3	Short Term Debt	81,793	35,705	37,945	56,157	88,058	97,321	102,164	80,145	21,600	16,224	11,177	27,103
4	Equity (simple mid year average)	157,198	152,260	147,491	143,990	141,840	145,505	152,138	155,168	157,997	158,426	156,332	159,524
5	Total Capitalization (simple mid year average)	480,885	444,142	438,553	450,204	473,260	483,087	492,303	488,573	477,268	472,321	463,752	481,627
6	**Weight**												
7	Long Term Debt	50.3%	57.7%	57.7%	55.5%	51.4%	49.7%	48.3%	51.8%	62.4%	63.0%	63.9%	61.3%
8	Short Term Debt	17.0%	8.0%	8.7%	12.5%	18.6%	20.1%	20.8%	16.4%	4.5%	3.5%	2.4%	5.6%
9	Equity	32.7%	34.3%	33.6%	32.0%	30.0%	30.1%	30.9%	31.8%	33.1%	33.5%	33.7%	33.1%
10	Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

11 Reference: PUB/Centra I-86 (a), PUB/Centra I - 78 (a) Attachmen 2008t & 2009 GRA, PUB/Centra 77 (a) Attachment 2010 & 2011 GRA

46.

($000's)

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Test Year	2013/14 Test Year	Compounded Annual Growth 2008/09 to 2011/12 % Inc/(Dec)	Compounded Annual Growth 2011/12 to 2013/14 % Inc/(Dec)
President & CEO	1,374	1,222	972	1,122	891	909	(6.5)	(10.0)
Finance & Administration	6,549	6,742	6,693	6,377	6,187	6,311	(0.9)	(0.5)
Power Supply	47	220	477	317	404	412	88.7	14.0
Transmission	224	255	250	99	194	197	(23.9)	41.3
Customer Service & Distribution	38,078	40,288	37,941	39,565	38,493	39,263	1.3	(0.4)
Customer Care & Marketing	19,765	18,670	17,845	18,195	17,575	17,926	(2.7)	(0.7)
Corporate Allocations & Adjustments	1,769	1,460	1,660	1,718	6,559	6,844	(1.0)	99.6
Program View - Operating & Administrative Expense	**$ 67,806**	**$ 68,857**	**$ 65,838**	**$ 67,393**	**$ 70,303**	**$ 71,862**	**(0.2)**	**3.3**
Less: Depreciation, Interest & Taxes included in above	(8,003)	(7,906)	(5,194)	(5,275)	(3,003)	(3,063)	(13.0)	(23.8)
Operating & Administrative Expense	**$ 59,803**	**$ 60,951**	**$ 60,644**	**$ 62,117**	**$ 67,300**	**$ 68,800**	**1.3**	**5.2**
Less: Accounting Changes	1,000	1 020	3 040	3 101	7 491	7 796		
OM&A after adjusting for Accounting Changes	**$ 58,803**	**$ 59,931**	**$ 57,604**	**$ 59,016**	**$ 59,809**	**$ 61,004**	**0.1**	**1.7**
Number of Customers	263,008	264,301	265,961	267,699	270,040	273,122		
<u>OM&A Cost per Customer:</u>								
Before Adjustments for Accounting Changes	$ 227	$ 231	$ 228	$ 232	$ 249	$ 252	0.7	4.2
After Adjustments for Accounting Changes	$ 224	$ 227	$ 217	$ 220	$ 221	$ 223	(0.5)	0.7

($000's)

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Test Year	2013/14 Test Year	Compounded Annual Growth 2008/09 to 2011/12 % Inc/(Dec)	Compounded Annual Growth 2011/12 to 2013/14 % Inc/(Dec)
President & CEO								
Audit	143	189	291	235	221	225	18.1	(2.1)
Liability Claims	358	147	(250)	7	80	82	(73.3)	246.1
Public Affairs	814	814	891	874	512	522	2.4	(22.7)
Research & Development	60	72	40	6	79	80	(53.5)	264.0
Total President & CEO	**$ 1,374**	**$ 1,222**	**$ 972**	**$ 1,122**	**$ 891**	**$ 909**	**(6.5)**	**(10.0)**
Finance & Administration								
IT - Distribution/Metering	181	123	134	102	121	124	(17.3)	10.1
IT - Banner	1,088	1,019	1,074	1,093	1,095	1,117	0.2	1.1
Gas Accounting	378	324	314	332	342	348	(4.3)	2.4
Gas Regulatory	1,652	2,199	1,905	1,525	1,949	1,988	(2.6)	14.2
Gas Supply	2,937	2,801	2,955	3,036	2,368	2,416	1.1	(10.8)
Treasury	260	258	282	280	312	318	2.4	6.6
Property Tax Administration	53	18	30	9	0	0	(44.6)	(100.0)
Total Finance & Administration	**$ 6,549**	**$ 6,742**	**$ 6,693**	**$ 6,377**	**$ 6,187**	**$ 6,311**	**(0.9)**	**(0.5)**
Power Supply								
Environmental Management	47	220	477	317	404	412	88.7	14.0
Total Power Supply	**$ 47**	**$ 220**	**$ 477**	**$ 317**	**$ 404**	**$ 412**	**88.7**	**14.0**
Transmission								
System Support & Communications Systems	224	255	250	99	194	197	(23.9)	41.3
Total Transmission	**$ 224**	**$ 255**	**$ 250**	**$ 99**	**$ 194**	**$ 197**	**(23.9)**	**41.3**
Customer Service & Distribution								
Billing Inquiry & Collections	2,088	2,563	2,376	1,895	1,772	1,807	(3.2)	(2.3)
Customer Inspections	10,356	10,518	9,750	9,718	8,982	9,162	(2.1)	(2.9)
Customer Relations	627	1,572	1,614	1,659	1,501	1,531	38.3	(3.9)
Dispatch	2,982	2,511	2,768	3,095	2,793	2,849	1.2	(4.0)
Customer Safety	2,228	2,152	2,166	1,936	1,922	1,961	(4.6)	0.6
Distribution Maintenance	8,362	8,407	7,417	7,385	7,252	7,397	(4.1)	0.1
Emergency	218	14	17	110	0	0	(20.3)	(100.0)
Regulating Station Maintenance	5,406	5,502	4,998	5,660	5,760	5,875	1.5	1.9
Capacity Analysis & Engineering	613	698	642	463	635	648	(8.9)	18.3
System Integrity	1,062	1,163	1,316	1,247	1,380	1,407	5.5	6.2
Meter Reading	1,829	1,861	1,928	1,970	2,015	2,056	2.5	2.1
Meter Changes	2,306	3,325	2,948	4,429	4,480	4,569	24.3	1.6
Total Customer Service & Distribution	**$ 38,078**	**$ 40,288**	**$ 37,941**	**$ 39,565**	**$ 38,493**	**$ 39,263**	**1.3**	**(0.4)**
Customer Care & Marketing								
Billing Inquiry & Collections	10,557	9,543	8,374	8,286	8,374	8,542	(7.8)	1.5
Customer Relations	6,485	6,643	6,473	6,390	6,262	6,387	(0.5)	0.0
Customer Safety	303	286	212	324	308	314	2.3	(1.6)
Quality Assessment	258	470	649	671	565	576	37.5	(7.4)
Load Forecast	156	166	158	173	192	196	3.6	6.4
Meter Repair & Calibration	2,007	1,562	1,978	2,351	1,874	1,911	5.4	(9.8)
Total Customer Care & Marketing	**$ 19,765**	**$ 18,670**	**$ 17,845**	**$ 18,195**	**$ 17,575**	**$ 17,926**	**(2.7)**	**(0.7)**
Corporate Allocations & Adjustments	1,769	1,460	1,660	1,718	6,559	6,844	(1.0)	99.6
Program View	**$ 67,806**	**$ 68,857**	**$ 65,838**	**$ 67,393**	**$ 70,303**	**$ 71,862**	**(0.2)**	**3.3**
Less: Depreciation, Interest & Taxes included in above	(8,003)	(7,906)	(5,194)	(5,275)	(3,003)	(3,063)	(13.0)	(23.8)
Operating & Administrative Expense	**$ 59,803**	**$ 60,951**	**$ 60,644**	**$ 62,117**	**$ 67,300**	**$ 68,800**	**1.3**	**5.2**
Less: Accounting Changes	1,000	1,020	3,040	3,101	7,491	7,796		
OM&A after adjusting for Accounting Changes	**$ 58,803**	**$ 59,931**	**$ 57,604**	**$ 59,016**	**$ 59,809**	**$ 61,004**	**0.1**	**1.7**
Number of Customers	263,008	264,301	265,961	267,699	270,040	273,122		
OM&A Cost per Customer:								
Before Adjustments for Accounting Changes	$ 227	$ 231	$ 228	$ 232	$ 249	$ 252	0.7	4.2
After Adjustments for Accounting Changes	$ 224	$ 227	$ 217	$ 220	$ 221	$ 223	(0.5)	0.7

CENTRA GAS MANITOBA INC.
OPERATING & ADMINISTRATIVE EXPENSE BY COST ELEMENT - 2008/09 TO 2013/14

($000's)

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Test Year	Compounded Annual Growth 2008/09 to 2011/12 % Inc/(Dec)	Compounded Annual Growth 2011/12 to 2013/14 % Inc/(Dec)
Activity Charges	42,413	44,410	45,918	46,574	41,453	42,282	3.2	(4.7)
Primary Costs:								
External Course, Awards	26	24	26	21	9	9	(6.7)	(33.2)
Material	1,476	1,294	1,184	1,170	1,337	1,364	(7.5)	8.0
Travel	124	87	102	79	135	137	(13.8)	31.6
Donations, Grants & Sponsorships	348	333	393	476	358	365	11.0	(12.4)
Memberships	142	170	176	188	180	184	10.0	(1.1)
Bad Debt & Collection Expense	2,135	2,086	1,613	1,435	1,559	1,590	(12.4)	5.2
Office Administration & Other	1,585	1,562	1,557	1,608	1,596	1,628	0.5	0.6
Computer Equipment & Maintenance	546	563	522	452	547	557	(6.1)	11.1
Meter Reading Charges (primarily MHUS)	2,288	2,425	1,949	2,130	2,126	2,169	(2.4)	0.9
Banking/Cash Management Services	192	222	220	255	284	290	9.9	6.6
Construction & Maintenance Services	1,051	1,240	947	1,823	1,138	1,160	20.1	(20.2)
Purchased Services	1,929	1,988	1,772	1,506	2,124	2,166	(7.9)	19.9
Promotional Items/Customer Incentives	40	25	57	71	27	28	21.3	(37.2)
Gas-PUB & Advisory Services	722	766	491	496	473	482	(11.8)	(1.4)
Operating Expense Recoveries	(561)	(537)	(620)	(598)	0	0	2.2	(100.0)
Other	5	4	1	(1)	(5)	(5)	(161.0)	110.6
Total Primary Costs	12,047	12,251	10,390	11,110	11,887	12,125	(2.7)	4.5
Corporate Allocations & Adjustments	1,769	1,460	1,660	1,718	6,559	6,844	(1.0)	99.6
Overhead	11,577	10,735	7,870	7,990	10,403	10,611	(11.6)	15.2
Total Program Costs	**$ 67,806**	**$ 68,857**	**$ 65,838**	**$ 67,392**	**$ 70,302**	**$ 71,862**	**(0.2)**	**3.3**
Depreciation, Interest & Taxes	(8,003)	(7,906)	(5,194)	(5,275)	(3,003)	(3,063)	(13.0)	(23.8)
Operating and Administrative Expense	**$ 59,803**	**$ 60,951**	**$ 60,644**	**$ 62,117**	**$ 67,300**	**$ 68,800**	**1.3**	**5.2**
Less: Accounting Changes	1,000	1,020	3,040	3,101	7,491	7,796		
OM&A after adjusting for Accounting Changes	**$ 58,803**	**$ 59,931**	**$ 57,604**	**$ 59,016**	**$ 59,809**	**$ 61,004**	**0.1**	**1.7**

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS AND OVERHEADS **($000's)**

	2008/09 Actual				2009/10 Actual			
	Primary	Activity Charges	Overhead	Program Costs	Primary	Activity Charges	Overhead	Program Costs
PRESIDENT & CEO								
Audit	47	75	20	143	71	95	23	189
Liability Claims	358	-	-	358	147	-	-	147
Public Affairs	485	259	70	814	502	252	60	814
Research & Development	51	7	2	60	66	5	1	72
	$ 941	**$ 341**	**$ 92**	**$ 1,374**	**$ 785**	**$ 353**	**$ 85**	**$ 1,222**
FINANCE & ADMINISTRATION								
IT - Distribution/Metering	-	142	38	181	0	99	24	123
IT - Banner	177	717	194	1,088	168	686	165	1,019
Gas Accounting	(1)	299	81	378	(0)	261	63	324
Gas Regulatory	728	728	196	1,652	806	1,123	270	2,199
Gas Supply	315	2,064	557	2,937	288	2,027	486	2,801
Treasury	260	-	0	260	258	-	-	258
Property Tax Administration	7	36	9	53	3	12	3	18
	$ 1,487	**$ 3,986**	**$ 1,076**	**$ 6,549**	**$ 1,524**	**$ 4,208**	**$ 1,010**	**$ 6,742**
POWER SUPPLY								
Environmental Management	3	35	9	47	157	51	12	220
	$ 3	**$ 35**	**$ 9**	**$ 47**	**$ 157**	**$ 51**	**$ 12**	**$ 220**
TRANSMISSION								
System Support & Communication Systems	29	153	41	224	25	186	45	255
	$ 29	**$ 153**	**$ 41**	**$ 224**	**$ 25**	**$ 186**	**$ 45**	**$ 255**
CUSTOMER SERVICE & DISTRIBUTION								
Billing Inquiry & Collections	26	1,624	439	2,088	11	2,058	494	2,563
Customer Inspections	451	7,780	2,125	10,356	550	8,024	1,944	10,518
Customer Relations	(6)	499	135	627	(8)	1,274	306	1,572
Dispatch	-	2,348	634	2,982	-	2,025	486	2,511
Customer Safety	(0)	1,754	474	2,228	8	1,729	415	2,152
Distribution Maintenance	959	5,785	1,618	8,362	985	5,961	1,461	8,407
Emergency	4	168	46	218	0	11	3	14
Regulating Station Maintenance	1,153	3,346	907	5,406	1,270	3,411	822	5,502
Capacity Analysis & Engineering	2	481	130	613	2	562	135	698
System Integrity	51	796	215	1,062	189	785	189	1,163
Meter Reading	1,743	68	18	1,829	1,811	40	10	1,861
Meter Changes	139	1,691	476	2,306	89	2,599	637	3,325
	$ 4,521	**$ 26,339**	**$ 7,217**	**$ 38,078**	**$ 4,907**	**$ 28,480**	**$ 6,900**	**$ 40,288**
CUSTOMER CARE & MARKETING								
Billing Inquiry & Collections	3,473	5,562	1,522	10,557	3,371	4,968	1,204	9,543
Customer Relations	1,143	4,207	1,136	6,485	1,063	4,500	1,080	6,643
Customer Safety	69	184	50	303	79	167	40	286
Quality Assessment	-	203	55	258	11	371	89	470
Load Forecast	2	121	33	156	9	127	30	166
Meter Repair & Calibration	378	1,282	347	2,007	322	1,000	240	1,562
	$ 5,065	**$ 11,558**	**$ 3,142**	**$ 19,765**	**$ 4,854**	**$ 11,132**	**$ 2,684**	**$ 18,670**
Corporate Allocations & Adjustments				1,769				1,460
TOTAL PROGRAM COSTS	**$ 12,047**	**$ 42,413**	**$ 11,577**	**$ 67,806**	**$ 12,251**	**$ 44,410**	**$ 10,735**	**$ 68,857**
Less: Depreciation, Interest & Taxes included in above				(8,003)				(7,906)
TOTAL OPERATING & ADMINISTRATIVE EXPENSE	**$ 12,047**	**$ 42,413**	**$ 11,577**	**$ 59,803**	**$ 12,251**	**$ 44,410**	**$ 10,735**	**$ 60,951**

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS AND OVERHEADS **($000's)**

	2010/11 Actual				2011/12 Actual			
	Primary	Activity Charges	Overhead	Program Costs	Primary	Activity Charges	Overhead	Program Costs
PRESIDENT & CEO								
Audit	82	179	30	291	64	146	25	235
Liability Claims	(250)	-	-	(250)	6	0	0	7
Public Affairs	584	262	45	891	550	278	47	874
Research & Development	35	4	1	40	0	5	1	6
	$ 451	**$ 445**	**$ 76**	**$ 972**	**$ 621**	**$ 429**	**$ 73**	**$ 1,122**
FINANCE & ADMINISTRATION								
IT - Distribution/Metering	0	114	19	134	-	87	15	102
IT - Banner	194	753	128	1,074	163	795	135	1,093
Gas Accounting	1	268	45	314	(0)	284	48	332
Gas Regulatory	500	1,201	204	1,905	508	869	148	1,525
Gas Supply	213	2,343	398	2,955	202	2,422	412	3,036
Treasury	281	1	0	282	280	-	-	280
Property Tax Administration	9	18	3	30	0	8	1	9
	$ 1,197	**$ 4,697**	**$ 799**	**$ 6,693**	**$ 1,153**	**$ 4,465**	**$ 759**	**$ 6,377**
POWER SUPPLY								
Environmental Management	355	104	18	477	155	139	24	317
	$ 355	**$ 104**	**$ 18**	**$ 477**	**$ 155**	**$ 139**	**$ 24**	**$ 317**
TRANSMISSION								
System Support & Communication Systems	16	199	34	250	14	73	11	99
	$ 16	**$ 199**	**$ 34**	**$ 250**	**$ 14**	**$ 73**	**$ 11**	**$ 99**
CUSTOMER SERVICE & DISTRIBUTION								
Billing Inquiry & Collections	18	2,015	343	2,376	10	1,611	274	1,895
Customer Inspections	14	8,309	1,427	9,750	(89)	8,371	1,436	9,718
Customer Relations	(4)	1,383	235	1,614	(8)	1,424	242	1,659
Dispatch	14	2,354	400	2,768	13	2,634	448	3,095
Customer Safety	1	1,850	315	2,166	6	1,649	281	1,936
Distribution Maintenance	659	5,754	1,004	7,417	737	5,655	992	7,385
Emergency	1	13	2	17	10	86	15	110
Regulating Station Maintenance	1,129	3,305	564	4,998	1,065	3,923	672	5,660
Capacity Analysis & Engineering	6	544	93	642	1	395	67	463
System Integrity	96	1,042	178	1,316	155	933	159	1,247
Meter Reading	1,877	44	7	1,928	1,924	40	7	1,970
Meter Changes	93	2,432	423	2,948	812	3,081	536	4,429
	$ 3,905	**$ 29,045**	**$ 4,991**	**$ 37,941**	**$ 4,636**	**$ 29,800**	**$ 5,128**	**$ 39,565**
CUSTOMER CARE & MARKETING								
Billing Inquiry & Collections	2,951	4,627	796	8,374	2,862	4,627	797	8,286
Customer Relations	1,026	4,655	792	6,473	1,115	4,508	767	6,390
Customer Safety	86	108	18	212	148	150	26	324
Quality Assessment	14	543	92	649	-	574	98	671
Load Forecast	17	121	21	158	7	142	24	173
Meter Repair & Calibration	370	1,374	234	1,978	401	1,667	284	2,351
	$ 4,465	**$ 11,427**	**$ 1,953**	**$ 17,845**	**$ 4,532**	**$ 11,669**	**$ 1,994**	**$ 18,195**
Corporate Allocations & Adjustments				1,660				1,718
TOTAL PROGRAM COSTS	**$ 10,390**	**$ 45,918**	**$ 7,870**	**$ 65,838**	**$ 11,110**	**$ 46,574**	**$ 7,990**	**$ 67,392**
Less: Depreciation, Interest & Taxes included in above				(5,194)				(5,275)
TOTAL OPERATING & ADMINISTRATIVE EXPENSE	**$ 10,390**	**$ 45,918**	**$ 7,870**	**$ 60,644**	**$ 11,110**	**$ 46,574**	**$ 7,990**	**$ 62,117**

CENTRA GAS MANITOBA INC.
ACTIVITY CHARGES, PRIMARY COSTS AND OVERHEADS **($000's)**

	2012/13 Forecast Primary	2012/13 Forecast Activity Charges	2012/13 Forecast Overhead	2012/13 Forecast Program Costs	2013/14 Test Year Primary	2013/14 Test Year Activity Charges	2013/14 Test Year Overhead	2013/14 Test Year Program Costs
PRESIDENT & CEO								
Audit	44	142	35	221	44	145	36	225
Liability Claims	80	-	-	80	82	-	-	82
Public Affairs	371	113	28	512	378	115	29	522
Research & Development	79	-	-	79	80	-	-	80
	$ 573	**$ 254**	**$ 64**	**$ 891**	**$ 584**	**$ 259**	**$ 65**	**$ 909**
FINANCE & ADMINISTRATION								
IT - Distribution/Metering	-	121	1	121	-	123	1	124
IT - Banner	207	710	178	1,095	211	725	181	1,117
Gas Accounting	-	273	68	342	-	279	70	348
Gas Regulatory	479	1,176	294	1,949	489	1,200	300	1,988
Gas Supply	279	1,671	418	2,368	285	1,705	426	2,416
Treasury	312	-	-	312	318	-	-	318
Property Tax Administration	-	-	-	-	-	-	-	-
	$ 1,277	**$ 3,951**	**$ 959**	**$ 6,187**	**$ 1,303**	**$ 4,031**	**$ 978**	**$ 6,311**
POWER SUPPLY								
Environmental Management	404	-	-	404	412	-	-	412
	$ 404	**$ -**	**$ -**	**$ 404**	**$ 412**	**$ -**	**$ -**	**$ 412**
TRANSMISSION								
System Support & Communication Systems	17	141	35	194	18	144	36	197
	$ 17	**$ 141**	**$ 35**	**$ 194**	**$ 18**	**$ 144**	**$ 36**	**$ 197**
CUSTOMER SERVICE & DISTRIBUTION								
Billing Inquiry & Collections	33	1,392	348	1,772	33	1,419	355	1,807
Customer Inspections	152	7,053	1,777	8,982	155	7,194	1,812	9,162
Customer Relations	0	1,201	300	1,501	0	1,225	306	1,531
Dispatch	50	2,195	549	2,793	51	2,239	560	2,849
Customer Safety	9	1,531	383	1,922	9	1,561	391	1,961
Distribution Maintenance	1,089	4,906	1,258	7,252	1,111	5,004	1,283	7,397
Emergency	-	-	-	-	-	-	-	-
Regulating Station Maintenance	1,239	3,614	907	5,760	1,263	3,687	925	5,875
Capacity Analysis & Engineering	108	422	106	635	110	430	108	648
System Integrity	249	905	226	1,380	254	923	231	1,407
Meter Reading	1,964	41	10	2,015	2,003	42	11	2,056
Meter Changes	115	3,484	881	4,480	117	3,553	899	4,569
	$ 5,006	**$ 26,742**	**$ 6,745**	**$ 38,493**	**$ 5,106**	**$ 27,277**	**$ 6,880**	**$ 39,263**
CUSTOMER CARE & MARKETING								
Billing Inquiry & Collections	3,004	4,288	1,082	8,374	3,064	4,374	1,104	8,542
Customer Relations	1,119	4,115	1,029	6,262	1,141	4,197	1,049	6,387
Customer Safety	122	149	37	308	124	152	38	314
Quality Assessment	15	440	110	565	15	449	112	576
Load Forecast	19	138	35	192	20	141	35	196
Meter Repair & Calibration	331	1,234	309	1,874	338	1,259	315	1,911
	$ 4,610	**$ 10,363**	**$ 2,601**	**$ 17,575**	**$ 4,703**	**$ 10,571**	**$ 2,653**	**$ 17,926**
Corporate Allocations & Adjustments				6,559				6,844
TOTAL PROGRAM COSTS	**$ 11,887**	**$ 41,453**	**$ 10,403**	**$ 70,303**	**$ 12,125**	**$ 42,282**	**$ 10,611**	**$ 71,862**
Less: Depreciation, Interest & Taxes included in above				(3,003)				(3,063)
TOTAL OPERATING & ADMINISTRATIVE EXPENSE	**$ 11,887**	**$ 41,453**	**$ 10,403**	**$ 67,300**	**$ 12,125**	**$ 42,282**	**$ 10,611**	**$ 68,800**

PUB/CENTRA I-20

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedule 5.5.0 - Manitoba Hydro's OM&A**

e) Please file a summary of wage settlements with Centra's unions.

ANSWER:

The following provides a summary of the contracted wage settlements since April 1, 2008.

Union	Effective Date	Wage Settlement
CEPU	December 25, 2008	2.90%
CEPU	December 22, 2010	1.00%
CEPU	December 23, 2010	2.50%
CEPU	December 22, 2011	2.50%
CEPU	December 22, 2012 (and beyond)	In Negotiations

In 2008, the 2.9% was 2.0% General Wage Increase and 0.9% special adjustment.

47.

$ in (000's) except Cost per Customer

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast	Compounded Annual Increase from 2003/04 to 2011/12 %	Compounded Annual Increase from 2011/12 to 2013/14 %
Centra Gas OM&A	$ 52,786	$ 55,232	$ 53,085	$ 53,505	$ 56,270	$ 59,803	$ 60,951	$ 60,644	$ 62,117	$ 67,300	$ 68,800	2.1	5.2
Less: Accounting Changes	$ -	$ -	$ -	$ -	$ -	$ 1,000	$ 1,020	$ 3,040	$ 3,101	$ 7,491	$ 7,796		
Centra Gas OM&A after adjusting for Accounting Changes	$ 52,786	$ 55,232	$ 53,085	$ 53,505	$ 56,270	$ 58,803	$ 59,931	$ 57,604	$ 59,016	$ 59,809	$ 61,004	1.4	1.7
% Increase		4.63%	-3.89%	0.79%	5.17%	4.50%	1.92%	-3.88%	2.45%	1.34%	2.00%		
Number of Customers	253,631	255,925	257,817	259,569	261,159	263,008	264,301	265,961	267,699	270,040	273,122		
Before Adjustments for Accounting Changes:													
Cost per Customer	$ 208	$ 216	$ 206	$ 206	$ 215	$ 227	$ 231	$ 228	$ 232	$ 249	$ 252		
% Increase (Decrease)		3.70%	-4.59%	0.11%	4.53%	5.53%	1.42%	-1.12%	1.76%	7.40%	1.08%		
After Adjustments for Accounting Changes:													
Cost per Customer	$ 208	$ 216	$ 206	$ 206	$ 215	$ 224	$ 227	$ 217	$ 220	$ 221	$ 223		
% Increase (Decrease)		3.70%	-4.59%	0.11%	4.53%	3.77%	1.42%	-4.48%	1.79%	0.47%	0.85%		
Canadian CPI	1.90%	2.20%	2.30%	1.90%	2.10%	2.20%	0.40%	2.00%	2.80%	1.80%	2.10%		

PUB/CENTRA I-17

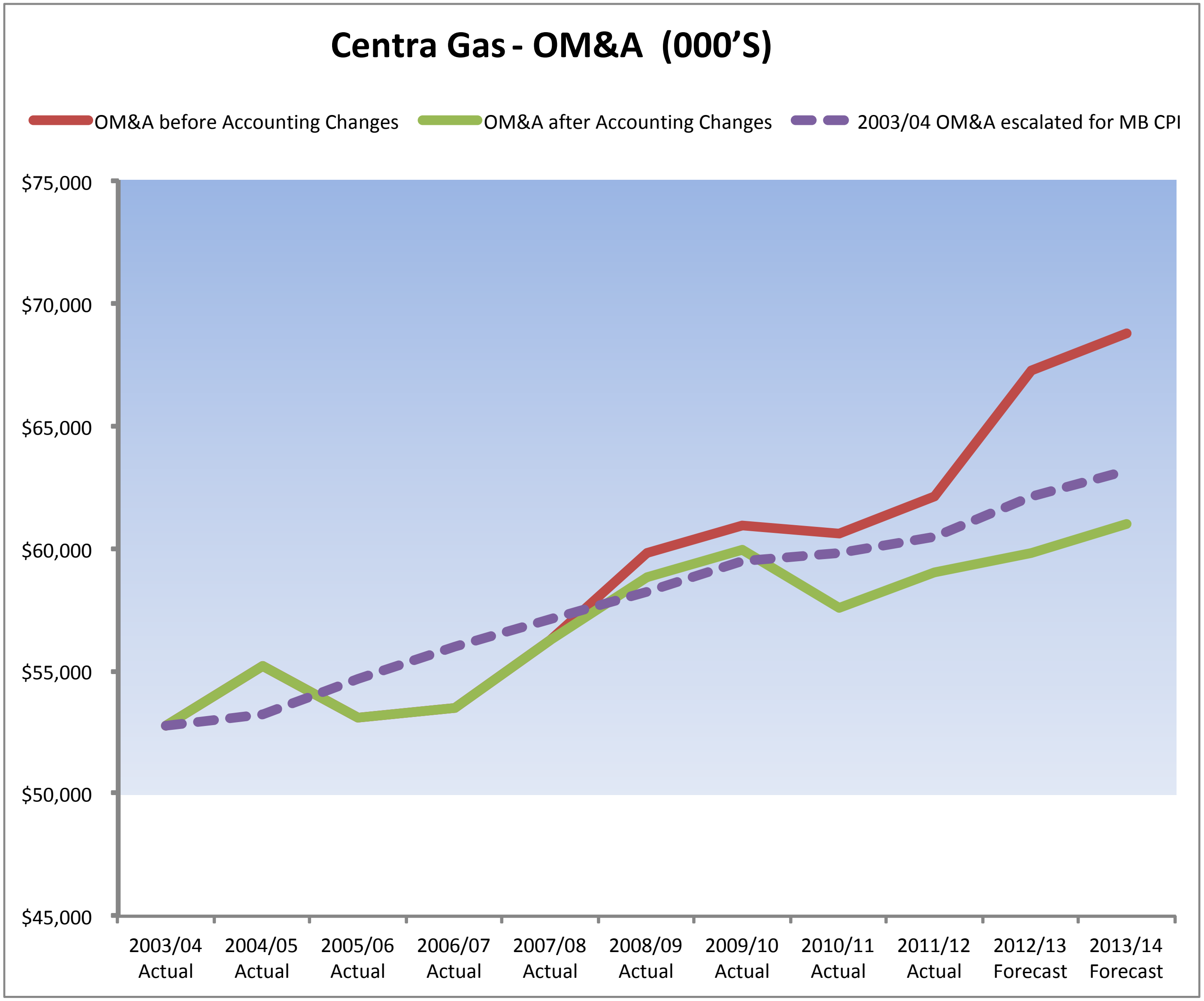
Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Schedules 5.5.0; Appendix 5.7 Pages 2 and 4 of 23;

b) Please provide a graph of top line OM&A growth before and after accounting changes from 2003/04 to 2013/14. Please include the 2003/04 OM&A escalated by Manitoba CPI for each year to 2013/14.

ANSWER:

Please see graph included below.


Centra Gas - OM&A (000'S)
OM&A before Accounting Changes
OM&A after Accounting Changes
2003/04 OM&A escalated for MB CPI
$75,000
$70,000
$65,000
$60,000
$55,000
$50,000
$45,000
2003/04 Actual
2004/05 Actual
2005/06 Actual
2006/07 Actual
2007/08 Actual
2008/09 Actual
2009/10 Actual
2010/11 Actual
2011/12 Actual
2012/13 Forecast
2013/14 Forecast

PUB/CENTRA I-17

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedules 5.5.0; Appendix 5.7 Pages 2 and 4 of 23;**

c) Please provide a schedule indicating the amounts incurred and capitalized in each year from 2008/09 to 2013/14 on the cost items identified in the table on page 4 that Centra now indicates it has or will expense.

ANSWER:

The table on page 4 of Appendix 5.7 provides the amounts in each of the fiscal years previously capitalized either through overhead or as an intangible asset that were, or will now be, expensed.

SUMMARY OF ACCOUNTING CHANGES - CENTRA GAS IFF12
(in thousands of dollars)

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Reduction to Costs Capitalized						
Interest on Common Assets (Facilities & Equipment)	-	-	1,000	1,020	1,040	1,061
General & Administrative Departmental Costs	-	-	500	510	520	531
Interest on Motor Vehicles	-	-	500	510	520	531
IT Infrastructure & Related Support	-	-	-	-	1,800	1,836
Building Depreciation & Operating Costs	-	-	-	-	1,000	1,020
	-	-	2,000	2,040	4,881	4,978
Intangible Assets						
Ineligible for Capitalization	1,000	1,020	1,040	1,061	1,082	1,104
	1,000	1,020	1,040	1,061	1,082	1,104

PUB/CENTRA I-7

Subject: **Tab 4 Integrated Financial Forecast & Economic Outlook**

Reference: **Tab 4 Pages 5 and 6 of 7 - IFRS**

The Canadian Accounting Standards Board (AcSB) recently announced an additional deferral to implement IFRS until 2015/16 including signaling the intention to issue an Interim standard that will "grandfather" rate regulated accounting.

b) Please file an updated CGM12 scenario including additional line items quantifying the net impact of accounting changes reflected in the IFF.

ANSWER:

Please see the following schedules:

Schedule A presents the net impacts of accounting changes by operating statement line item under CGAAP and IFRS. Schedule B presents the net impacts of the accounting changes to Retained Earnings. Please note that at the time of the preparation of CGM12, it was assumed that IFRS would be implemented during the 2014/15 fiscal year.

Narratives referencing the changes are provided following schedules A & B.

Schedules C & D reflect the impact of the accounting changes in the income statement and balance sheet of CGM12, respectively.

SCHEDULE A - CENTRA GAS ACCOUNTING CHANGES - CGM12

	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast --> 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Ref
Gas only (in millions of $'s)															
OM&A															
CGAAP Changes															
Intangibles															
DSM (research & promotion)	1	1	1	1	1	1	1	1	1	1	1	1	1	1	**1**
Total	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Overhead Capitalized															
Admin & General Overhead			2	2	5	5	5	5	5	5	6	6	6	6	**2**
Total	-	-	2	2	5	5	5	5	5	5	6	6	6	6	
Change in Discount Rate on Pension & Other Benefits					1	1	1	1	1	1	1	1	1	1	**3**
Operating Expense Recoveries (Reclassification)					1	1	1	1	1	1	1	1	1	1	**4**
Total CGAAP Changes	**1**	**1**	**3**	**3**	8	8	8	8	8	8	8	9	9	9	
IFRS Changes															
DSM*							8	7	7	5	4	3	3	3	**5**
Regulatory Costs*							1	-	1	1	1	1	1	1	**5**
Admin & General Overhead							2	2	2	2	2	2	2	2	**6**
Meter Changes							(5)	(5)	(5)	(5)	(5)	(6)	(6)	(6)	**7**
Total IFRS Changes						-	6	4	5	3	2	0	0	0	
Total OM&A Accounting Changes	**1**	**1**	**3**	**3**	**8**	**8**	**14**	**12**	**13**	**11**	**10**	**9**	**9**	**9**	

*** Rate-regulated account**

SCHEDULE A - CENTRA GAS ACCOUNTING CHANGES - CGM12 cont'd	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast --> 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Ref
DEPRECIATION EXPENSE															
CGAAP Changes															
Average Service Life				(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	**8**
Total CGAAP Changes	-	-	-	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	
IFRS Changes															
Reduction in Rate Regulated Assets*							(9)	(9)	(9)	(9)	(9)	(9)	(8)	(7)	**5**
Increase for Meter Changes							-	-	-	-	-	1	1	1	**7**
Change to Equal Life Group Depreciation Method							2	2	3	3	3	3	3	3	**9**
Removal of Net Salvage from depreciation rates							(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	**10**
Total IFRS Changes	-	-	-	-	-	-	(12)	(12)	(11)	(12)	(12)	(11)	(10)	(9)	
Total Depreciation Expense Accounting Changes	-	-	-	**(1)**	**(1)**	**(1)**	**(13)**	**(13)**	**(12)**	**(13)**	**(13)**	**(12)**	**(11)**	**(10)**	
FINANCE EXPENSE															
CGAAP Changes															
IFRS Changes*							2	2	2	2	1	1	1	1	**11**
Total Finance Expense Accounting Changes	-	-	-	-	**-**	**-**	**2**	**2**	**2**	**2**	**1**	**1**	**1**	**1**	
CAPITAL & OTHER TAX EXPENSE															
CGAAP Changes															
IFRS Changes*							(4)	(4)	(4)	(3)	(3)	(3)	(3)	(3)	**11**
Total Tax Expense Accounting Changes	-	-	-	-	**-**	**-**	**(4)**	**(4)**	**(4)**	**(3)**	**(3)**	**(3)**	**(3)**	**(3)**	

*** Rate-regulated account**

SCHEDULE B - CENTRA GAS ACCOUNTING CHANGES IMPACT TO RETAINED EARNINGS - CGM12															
Gas only (in millions of $'s)	**Actual**	**Actual**	**Actual**	**Actual**	**Forecast -->**										
IMPACT TO RETAINED EARNINGS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	**Total**
CGAAP Changes															
Retrospective adjustment for intangible Assets		(2)													**(2)**
Annual change to OM&A	(1)	(1)	(3)	(3)	(7)	(7)	(7)	(7)	(8)	(8)	(8)	(8)	(8)	(8)	**(84)**
Annual change to Depreciation & Amortization	-	-	-	1	1	1	1	1	1	1	1	1	1	1	**11**
Total CGAAP changes	**(1)**	**(3)**	**(3)**	**(2)**	**(6)**	**(6)**	**(6)**	**(6)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(7)**	**(75)**
IFRS Changes															
Annual change to OM&A	-	-	-	-	-	-	(6)	(4)	(5)	(3)	(2)	(0)	(0)	(0)	**(20)**
Annual change to Depreciation & Amortization	-	-	-	-	-	-	12	12	11	12	12	11	10	9	**90**
Annual change to Finance & Taxes	-	-	-	-	-	-	2	2	2	1	2	2	2	2	**15**
Write Offs to:															
Power Smart Programs							(48)								**(48)**
Site Remediation							(2)								**(2)**
Regulatory Costs							(1)								**(1)**
Deferred Taxes							(27)								**(27)**
Administrative Overhead (2013/14)							(2)								**(2)**
Removal of Net Salvage Depreciation (2013/14)							5								**5**
Change to Equal Life Group Depreciation (2013/14)							(2)								**(2)**
Total IFRS changes	**-**	**-**	**-**	**-**	**-**		**(69)**	**10**	**8**	**10**	**12**	**13**	**12**	**11**	**7**
Total Annual Impact to Retained Earnings	**(1)**	**(3)**	**(3)**	**(2)**	**(6)**	**(6)**	**(76)**	**4**	**2**	**4**	**6**	**6**	**5**	**4**	**(68)**

Reference	Description	Accounting Handbook Reference
1	The OM&A adjustments for intangible assets under CGAAP reflect a change (new section 3064 Goodwill and Intangible Assets) in the Canadian accounting standards for Goodwill and Intangible assets that was effective for MH April 1, 2009. The new standard was harmonized with IFRS and required research and promotional costs to be expensed as incurred with retrospective application. Approximately $2 million was adjusted to retained earnings in fiscal 2009/10 for research and promotional costs included in opening intangible asset balances. Effective April 1, 2009 and forward, research and promotional costs associated with intangible assets are expensed as incurred	**CGAAP – Section 3064 Goodwill and Intangible Assets** .37 No intangible asset arising from research (or from the research phase of an internal project) should be recognized. Expenditure on research (or on the research phase of an internal project) should be recognized as an expense when it is incurred. [OCT. 2008] .52 In some cases, expenditure is incurred to provide future economic benefits to an entity, but no intangible asset or other asset is acquired or created that can be recognized, ,Other examples of expenditure that is recognized as an expense when it is incurred include expenditure on: (a) start-up activities (i.e., start-up costs) (b) training activities (c) advertising and promotional activities.
2	The reduction in administrative and general overhead capitalized reflects adjustments made under CGAAP to become more consistent with other Canadian utilities. The adjustments result in the following: • an annual increase in operating and administrative expense; • reductions in plant asset values for amounts no longer capitalized; and • reductions in depreciation expense as a result of reduced asset values.	**CGAAP – Section 3061 Property, plant & equipment:** .20 The cost of an item of property, plant and equipment includes direct construction or development costs (such as materials and labour), and overhead costs directly attributable to the construction or development activity.

Reference	Description	Accounting Handbook Reference
3	The increase in the pension and employee benefits cost is a result of a reduction in the 2011/12 discount rate and the corresponding increase in current service cost for employee benefits.	**CGAAP – Section 3461 Employee Future Benefits:** .50 For a defined benefit plan, the discount rate used to determine the accrued benefit obligation should be an interest rate determined by reference to: (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. [JAN. 2000] .54. The discount rate is re-evaluated at each measurement date. When long-term interest rates rise or decline, the discount rate changes in a similar manner.
4	The adjustments for operating expense recoveries are to comply with the financial reporting requirements of IFRS. Revenues that were once netted against operating costs for financial reporting will be reported as revenue in the future as IFRS generally does not permit netting of revenues and expenses.	**IFRS - IAS 1 Presentation of Financial Statements:** . 32 - An entity shall not offset assets and liabilities or income and expenses, unless required or permitted by an IFRS.
5	IFF 12 assumes rate-regulated accounting is not permitted under IFRS and thus, rate-regulated accounting will be eliminated upon transition. The impacts of this assumption are as follows • upon transition to IFRS, a one-time adjustment to retained earnings will be made for unamortized rate-regulated account balances; • future expenditures on these items will be expensed as incurred resulting in an annual increase to operating and administrative	Unlike CGAAP and US GAAP, currently, there is no specific IFRS standard that permits rate-regulated accounting. Generally, the application of the existing IFRS framework has not resulted in the recognition of regulatory assets and liabilities. Recently, the IASB has re-initiated its project on rate regulated accounting and plans to issue a draft interim standard permitting rate regulated entities, that will be adopting IFRS for the first time, to continue to apply their existing rate-

Reference	Description	Accounting Handbook Reference
	expense; and • a reduction to depreciation and amortization for previously deferred regulatory accounts.	regulated accounting practices until the IASB's project is complete. This decision by the IASB was made subsequent to the completion of IFF12.
6	The reduction in administrative and general overhead capitalized reflects adjustments to comply with IFRS upon transition. IFRS does not permit the capitalization of general administrative and overhead costs. The adjustments result in the following: • an annual increase in operating and administrative expense; • reductions in plant asset values for amounts no longer capitalized; and • reductions in depreciation expense as a result of reduced asset values.	**IFRS - IAS 16 Property, plant & equipment:** .19 Examples of costs that are not costs of an item of property, plant and equipment are:, (d) administration and other general overhead costs.
7	CGM12 assumed that upon transition to IFRS, Centra would commence capitalization of the labour costs associated with meter exchange activities. This potential accounting treatment is being driven by the requirement under IFRS to harmonize the accounting policies of a parent company and its subsidiaries. Manitoba Hydro currently capitalizes such costs. This potential change is in the preliminary review stage and additional work is required with respect to the interpretation of the IFRS standards as well as a review of industry practices expected upon conversion to IFRS. The adjustments result in the following: • an annual decrease in operating and administrative expense;	**IFRS 10 Consolidated Financial Statements** 19 . A parent shall prepare consolidated financial statements using uniform accounting policies for like transactions and other events in similar circumstances. **Uniform accounting policies** B87. If a member of the group uses accounting policies other than those adopted in the consolidated financial statements for like transactions and events in similar circumstances, appropriate adjustments are made to that group member's financial statements in preparing the consolidated financial statements to ensure conformity with the group's accounting policies.

Reference	Description	Accounting Handbook Reference
	• increases in plant asset values for amounts capitalized; and • increases in depreciation expense as a result of the capitalization of such costs.	
8	The net result of the depreciation study under CGAAP and the average service life approach is an overall reduction in annual depreciation expense for Centra due to changes in the service lives for certain asset groups. This change is required to be implemented under Canadian GAAP.	**CGAAP – 3061 Property, plant & equipment:** .28 Amortization should be recognized in a rational and systematic manner appropriate to the nature of an item of property, plant and equipment with a limited life and its use by the enterprise. .33 The amortization method and estimates of the life and useful life of an item of property, plant and equipment should be reviewed on a regular basis. [DEC. 1990 *]
9	Upon adoption of IFRS, MH will be moving from the Average Service Life method of depreciation to the Equal Life Group method; increasing annual depreciation expense.	**IFRS - IAS 16 Property, plant & equipment:** The key IFRS reference supporting the move to the ELG method is: .43 Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item shall be depreciated separately. .68 The gain or loss arising from the de-recognition of an item of property, plant and equipment shall be included in profit or loss when the item is de-recognised. Gains shall not be classified as revenue.
10	Upon adoption of IFRS, MH will be removing the impact of net salvage from depreciation rates; decreasing annual depreciation expense.	-The Inclusion of net salvage in depreciation rates is a regulatory practice applied under CGAAP by Canadian utilities. Given that IFRS does not have a standard that

Reference	Description	Accounting Handbook Reference
		permits rate-regulated accounting, it was assumed in CGM12 that the practice of including negative salvage in depreciation rates would be discontinued upon transition to IFRS. -Recently, the IASB has re-initiated its project on rate regulated accounting and plans to issue a draft interim standard permitting rate regulated entities,that will be adopting IFRS for the first time, to continue to apply their existing rate-regulated accounting practices until the IASB's project is complete. This decision by the IASB was made subsequent to the completion of IFF12.
11	The changes to finance expense and capital and other taxes reflects primarily the elimination of the annual deferral of the carrying charges on the Centra Deferred Tax balance and the elimination of the annual amortization of the Deferred Tax balance upon transition to IFRS.	Unlike CGAAP and US GAAP, currently, there is no specific IFRS standard that permits rate-regulated accounting. Generally, the application of the existing IFRS framework has not resulted in the recognition of regulatory assets and liabilities. The deferral of the carrying charges on the Centra Deferred Tax balance and the amortization of the Deferred Tax balance was a regulatory accounting practice that is currently not permitted under IFRS. Recently, the IASB has re-initiated its project on rate regulated accounting and plans to issue a draft interim standard permitting rate regulated entities, that will be adopting IFRS for the first time, to continue to apply their existing rate-regulated accounting practices until the IASB's project is complete. This decision by the IASB was made subsequent to the completion of IFF12.

SCHEDULE C - ACCOUNTING CHANGES - IMPACT ON CGM12

GAS OPERATIONS (CGM12)
PROJECTED OPERATING STATEMENT
Net Impact of Accounting Changes
(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*	0	7	7	7	7	9	11	13	15	18
	319	319	363	358	356	357	360	362	365	368
Cost of Gas Sold	176	168	212	203	202	201	201	201	201	201
Gross Margin	143	151	151	155	154	156	159	161	164	167
Other	1	1	1	1	1	1	1	1	1	1
CGAAP Accounting Changes - reclassifications:	1	1	1	1	1	1	1	1	1	1
	145	**153**	**153**	**156**	**156**	**158**	**161**	**163**	**166**	**169**
EXPENSES										
Operating and Administrative	59	61	63	65	65	67	69	70	72	73
CGAAP Accounting Changes:										
Changes to Intangibles - research & promotion	1	1	1	1	1	1	1	1	1	1
Reduction in Administrative and General Overhead Capitalized	5	5	5	5	5	5	6	6	6	6
Change in Discount Rate	1	1	1	1	1	1	1	1	1	1
Reclassifications	1	1	1	1	1	1	1	1	1	1
IFRS Accounting Changes:										
DSM & Regulatory Costs*			9	7	8	6	5	4	4	4
Reduction in Administrative and General Overhead Capitalized			2	2	2	2	2	2	2	2
Meter Changes			(5)	(5)	(5)	(5)	(5)	(6)	(6)	(6)
Finance Expense	18	17	19	20	21	23	24	25	26	27
IFRS Accounting Changes*			2	2	2	2	1	1	1	1
Depreciation and Amortization	29	31	33	34	34	35	36	35	35	35
CGAAP Accounting Changes - ASL:	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
IFRS Accounting Changes:										
Reduction for Regulatory Assets*			(9)	(9)	(9)	(9)	(9)	(9)	(8)	(7)
Increase for Meter Changes			-	-	-	-	-	1	1	1
Change to Equal Life Group Method			2	2	3	3	3	3	3	3
Removal of Net Salvage	-		(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)
Capital and Other Taxes	18	19	19	19	20	19	19	20	20	20
IFRS Accounting Changes*			(4)	(4)	(4)	(3)	(3)	(3)	(3)	(3)
Corporate Allocation	12	12	12	12	12	12	12	12	12	12
	143	**147**	**144**	**147**	**151**	**153**	**155**	**158**	**161**	**165**
Net Income	**2**	**6**	**9**	**9**	**5**	**5**	**6**	**5**	**5**	**4**

*** Rate-regulated account**

SCHEDULE D - ACCOUNTING CHANGES - IMPACT ON CGM12

GAS OPERATIONS (CGM12)
PROJECTED BALANCE SHEET
Net Impact of Accounting Changes
(In Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS										
Plant in Service	665	693	723	755	789	812	837	864	891	919
CGAAP Accounting Changes pre 2013:	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
CGAAP Accounting changes	(5)	(10)	(15)	(20)	(25)	(31)	(36)	(42)	(48)	(54)
IFRS Accounting Changes:			1	4	7	11	14	18	21	25
Accumulated Depreciation	(234)	(243)	(255)	(266)	(277)	(290)	(303)	(316)	(330)	(345)
CGAAP Accounting Changes pre 2013:	1	1	1	1	1	1	1	1	1	1
CGAAP Accounting changes	1	2	3	4	5	6	7	8	9	10
IFRS Accounting Changes:			6	9	11	14	17	19	21	24
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	84	84	83	73	69	63	57	49	43	37
CGAAP Accounting Changes pre 2013:	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
CGAAP Accounting changes	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
IFRS Accounting Changes:			(76)	(65)	(60)	(53)	(46)	(37)	(30)	(23)
Total Assets	**586**	**594**	**536**	**557**	**580**	**595**	**610**	**625**	**640**	**655**
LIABILITIES AND EQUITY										
Long-Term Debt	295	290	330	340	360	380	390	400	420	410
Current and Other Liabilities	99	96	67	69	68	56	57	57	48	69
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	51	62	70	75	78	81	80	80	81	81
CGAAP Accounting Changes pre 2013:	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
CGAAP Accounting Changes:	(6)	(12)	(18)	(25)	(31)	(38)	(45)	(52)	(59)	(66)
IFRS Accounting Changes:			(69)	(59)	(51)	(41)	(28)	(16)	(4)	7
Total Liabilities & Equity	**586**	**594**	**536**	**557**	**580**	**595**	**610**	**625**	**640**	**655**

48.

PUB/CENTRA I-31

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Appendix 5.7 Page 21 of 23 Capitalized OM&A**

a) **Please provide Manitoba Hydro's corporate accounting policy on capitalizing OM&A and other expenses and comment on any changes, if any, in the policy since the 2009/10 & 2010/11 GRA.**

ANSWER:

Manitoba Hydro's Corporate accounting policy with respect to the capitalization of OM&A and other costs is as follows:

Property, plant & equipment is stated at cost which includes direct labour, materials, contracted services, a proportionate share of overhead costs and interest applied at the average cost of debt. Interest is allocated to construction until a capital project becomes operational or a decision is made to abandon, cancel or indefinitely defer construction. Once the transfer to in-service property, plant and equipment is made, interest allocated to construction ceases, and depreciation and interest charged to operations commences.

In general, this policy has not changed since the 2009/10 and 2010/11 GRA, but the types of overhead costs included for capitalization has. Historically under CGAAP, the Corporation has utilized a "full cost" accounting approach to the capitalization of administrative and overhead costs. This approach recognized that approximately 40% of the Corporation's activities are directed towards the construction of capital assets and thus, capital activities should receive a proportionate share of overhead costs.

Over the past several years, the Corporation has made changes to its overhead capitalization practices as a result of industry trends to move away from the capitalization of costs that do not vary with the level of capital activity in an organization and as a result, cannot be directly linked to capital projects. As presented on page 4 of Appendix 5.7 of the Application, Centra implemented changes to overheads included for capitalization in 2010/11 and forward so as to ensure that Centra's capitalization practices were consistent with those of other utilities. Under CGAAP, the Corporation removed from overhead capitalized, costs that would exist regardless of the level of capital activity in the Corporation. The following provides further information as to the costs that are no longer capitalized by Centra as presented in Appendix 5.7:

Interest on Common Assets and Motor vehicles

Examples of common assets include shared buildings such as 360 Portage Ave and 820 Taylor Ave., shared communication equipment and infrastructure, and shared computer systems such as the Banner and Web Trader systems. The category of motor vehicles represents the vehicles and equipment used for the gas operations and capital activities. Per discussions with other utilities, no utilities were including in overhead capitalized interest on common assets or motor vehicles. Given that the interest on the costs to construct and acquire such assets is already capitalized in their book value cost, the inclusion of additional interest on these assets in overhead eligible for capitalization was considered an aggressive capitalization practice.

General & Administrative Departmental Costs

General & administrative departmental costs include the costs associated with certain Corporate departments such as General Counsel, Corporate Document Services, Cash Management and Corporate Accounting. These departments provide support services that are shared across the organization would exist regardless of the level of construction activities of the Corporation. The Corporation has thus removed such costs from overhead capitalized.

IT Infrastructure & Related Support

This category includes general IT & system support (including staff) charges that would exist regardless of whether or not Centra incurred capital spending. The primary IT system included in this category is the SAP system and its fully integrated modules including financial accounting, human resource management, materials management, and the distribution planning maintenance system. While such systems vary in size relative to the activities of the Corporation, such systems would be required regardless of the level of capital activity. Similar to general and administrative department costs, such charges are no longer included in overhead capitalized.

Building Depreciation and Operating Costs

Included in this category are depreciation, maintenance, and operating costs of common building facilities such as 360 Portage, and 820 Taylor Ave. and the various operating centers. As described above with respect to other charges removed from overhead capitalized, such buildings would be required regardless of the level of capital activity within the Corporation and thus, depreciation and operating costs associated with common buildings are no longer included in overhead capitalized.

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.

49.

PUB/CENTRA I-24

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.7 Pages 3 and 4 of 23 – Accounting Changes**

a) **Please explain how the split between electric and gas operations was determined for the five cost items now proposed to be expensed for 2012/13 and 2013/14.**

ANSWER:

The split of these costs between electric and gas operations is as follows:

- Interest on Common Assets, Interest on Motor Vehicles, IT Infrastructure and Related Support & Building Depreciation & Operation Costs - 90% to Electric operations and 10% to Gas operations using activity charges as the driver for the allocation. These cost items are incurred in support the staff of the utilities, therefore activity charges is an appropriate cost driver as it aligns with the time spent by the staff between electric and gas operations.
- General & Administrative Department Costs – 96% to Electric operations and 4% to Gas operations using Total Assets as the driver for the allocation. The areas included in this category provide a corporate governance function. The value of the assets was viewed as an appropriate cost allocation driver as it represents the relative size of the utilities.

PUB/CENTRA I-20

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedule 5.5.0 - Manitoba Hydro's OM&A**

a) **Please provide a schedule that details Manitoba Hydro's overall OM&A expense by business unit, the amounts allocated or directly assigned to Centra for each of the business units and the percentage of the total allocated for each for the years 2008/09 through 2013/14.**

ANSWER:

Please see the schedule below. It is noted that the schedule does not include OM&A expenses charged to Centra through Corporate Allocations and Adjustments (CAA).

The decrease in the percentage allocated to the business units between 2011/12, the 2012/13 forecast year and the 2013/14 test year is due to the reallocation of information technology support costs and administrative building costs previously included in activity or overhead rates which are now directly allocated to Centra through CAA using cost drivers.

($000's)	2008/09 Actual Total Operating Costs Consolidated	Program Costs Centra Gas	Allocated %	2009/10 Actual Total Operating Costs Consolidated	Program Costs Centra Gas	Allocated %	2010/11 Actual Total Operating Costs Consolidated	Program Costs Centra Gas	Allocated %
President & CEO	24,230	1,374	5.7%	31,578	1,222	3.9%	28,835	972	3.4%
Corporate Relations	5,520	-	0.0%	4,697	-	0.0%	4,739	-	0.0%
Finance & Administration	103,722	6,549	6.3%	108,914	6,742	6.2%	106,528	6,693	6.3%
Power Supply	142,183	47	0.0%	147,073	220	0.1%	150,120	477	0.3%
Transmission	91,088	224	0.2%	92,302	255	0.3%	90,493	250	0.3%
Customer Service & Distribution	103,762	38,078	36.7%	111,068	40,288	36.3%	106,707	37,941	35.6%
Customer Care & Marketing	38,942	19,765	50.8%	42,395	18,671	44.0%	41,446	17,845	43.1%
	509,446	66,037	13.0%	538,027	67,397	12.5%	528,867	64,178	12.1%

($000's)	2011/12 Actual Total Operating Costs Consolidated	2011/12 Actual Program Costs Centra Gas	2011/12 Actual Allocated %	2012/13 Test Year Total Operating Costs Consolidated	2012/13 Test Year Program Costs Centra Gas	2012/13 Test Year Allocated %	2013/14 Test Year Total Operating Costs Consolidated	2013/14 Test Year Program Costs Centra Gas	2013/14 Test Year Allocated %
President & CEO	28,328	1,122	4.0%	28,692	891	3.1%	29,266	909	3.1%
Corporate Relations	3,025	-	0.0%	4,491	-	0.0%	4,581	-	0.0%
Finance & Administration	107,443	6,377	5.9%	114,343	6,187	5.4%	116,630	6,311	5.4%
Power Supply	155,084	317	0.2%	177,982	404	0.2%	181,541	412	0.2%
Transmission	89,261	99	0.1%	104,762	194	0.2%	106,857	197	0.2%
Customer Service & Distribution	110,045	39,564	36.0%	130,358	38,493	29.5%	132,966	39,263	29.5%
Customer Care & Marketing	43,703	18,195	41.6%	51,749	17,575	34.0%	52,784	17,926	34.0%
	536,889	65,674	12.2%	612,377	63,744	10.4%	624,624	65,019	10.4%

PUB/CENTRA I-20

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Schedule 5.5.0 - Manitoba Hydro's OM&A**

b) Please indicate which expenses are directly assigned versus indirectly assigned, and the cost drivers used for the appropriate assignment.

ANSWER:

Please see the schedule below.

('000s)

($000's)	2008/09 Actual Direct	2008/09 Actual Indirect	2009/10 Actual Direct	2009/10 Actual Indirect	2010/11 Actual Direct	2010/11 Actual Indirect	2011/12 Actual Direct	2011/12 Actual Indirect	2012/13 Forecast Direct	2012/13 Forecast Indirect	2013/14 Test Year Direct	2013/14 Test Year Indirect
President & CEO	558	817	309	913	105	867	145	977	328	563	334	575
Finance & Administration	5,104	1,445	5,415	1,327	5,253	1,440	4,926	1,451	4,745	1,442	4,840	1,471
Power Supply	47	-	220	-	477	-	317	-	404	-	412	-
Transmission	206	18	240	15	233	16	84	14	181	13	184	13
Customer Service & Distribution	32,080	5,998	32,557	7,731	30,398	7,543	32,351	7,213	32,121	6,373	32,763	6,500
Customer Care & Marketing	14,538	5,227	9,445	9,226	9,553	8,292	9,802	8,393	9,237	8,337	9,422	8,504
	52,533	13,504	48,185	19,213	46,019	18,158	47,625	18,049	47,015	16,728	47,956	17,063

The following table provides common cost drivers that are used to allocate integrated activities.

Driver	Electric	Gas	Common Order Examples	Rationale
Customers	67%	33%	Bill Insertion Operations	1
Customers	67%	33%	Joint Billing Initiative	1
Total Assets	96%	4%	Donations, Grants & Sponsorships	2
Total Assets	96%	4%	Audit Costs - Common	2
Total Assets	96%	4%	Public Affairs - Common	2
Total Assets	96%	4%	Corporation Memberships - Common	2
Credit & Recovery Services Activity	60%	40%	Collection Agency	3
Activity Charges	90%	10%	Awards & Service Recognition	4
Activity Charges	90%	10%	Operating Contingency	4
Activity Charges	Various	Various	Line Locates	5
Activity & Frequency	Various	Various	Safety Watches	5

Rationale for allocations:

1. These types of costs are driven by the number customers.
2. This is a general driver that represents the relative size of the utilities.
3. This allocation is based on activity charges of the Credit & Recovery Services Department activity.
4. This is a general driver that represents the relative amount of activity charges by staff to each of the utilities.
5. Where specific departments perform gas and electric functions simultaneously (e.g. line locates) the cost driver is based upon the relative estimate of time required and the frequency of the task performed for each of the utilities. The relative percentages range from 50% electric and 50% gas to 96% electric and 4% gas.

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.

						($000's)
	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
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-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.

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CENTRA GAS MANITOBA INC.
Finance Expense

($000's)

	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
Interest on Long Term Debt	13,762	13,547	13,753	14,305	14,142	14,390	13,336	12,544
Interest on Short Term Debt	3,349	4,665	2,758	342	131	102	22	284
Total Interest on Debt	17,111	18,212	16,511	14,647	14,274	14,492	13,358	12,828
Add:								
Provincial Guarantee Fee	3,079	3,217	3,282	3,382	3,142	3,103	3,048	2,975
Amortization of Debt Discounts	1,692	1,253	1,256	1,262	298	318	167	-
Interest on Common Assets	2,139	2,244	2,384	2,398	2,805	2,703	2,896	3,020
Interest on Inventory	25	32	25	104	93	104	148	151
Total Additions	6,933	6,747	6,947	7,146	6,337	6,228	6,259	6,146
Deduct:								
Capitalized Interest	(145)	(206)	(193)	(134)	(142)	(210)	(174)	(113)
Carrying Costs on Deferred Taxes	(3,352)	(3,156)	(2,996)	(2,850)	(2,704)	(2,565)	(2,412)	(2,266)
Carrying Costs on Purchased Gas Variance Account	1,539	66	(158)	(43)	(15)	262	584	332
Other	9	49	48	154	138	257	286	369
Total Deductions	(1,949)	(3,248)	(3,299)	(2,873)	(2,723)	(2,255)	(1,716)	(1,678)
Total Finance Expense	**22,095**	**21,711**	**20,158**	**18,921**	**17,888**	**18,464**	**17,901**	**17,296**

CENTRA GAS MANITOBA INC.
Finance Expense (000's)

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual
Interest on Long Term Debt	13,753	14,305	14,142	14,390
Interest on Short Term Debt	2,758	342	131	102
Total Interest on Debt	16,511	14,647	14,274	14,492
Add:				
Provincial Guarantee Fee	3,282	3,382	3,142	3,103
Amortization of Debt Discounts	1,256	1,262	298	318
Interest on Common Assets	2,384	2,398	2,805	2,703
Interest on Inventory	25	104	93	104
Total Additions	6,947	7,146	6,337	6,228
Deduct:				
Capitalized Interest	(193)	(134)	(142)	(210)
Carrying Costs on Deferred Taxes	(2,996)	(2,850)	(2,704)	(2,565)
Carrying Costs on Purchased Gas Variance Account	(158)	(43)	(15)	262
Other	48	154	138	257
Total Deductions	(3,299)	(2,873)	(2,723)	(2,255)
Total Finance Expense	**20,158**	**18,921**	**17,888**	**18,464**

	2008/09 **Forecast** (CGM08-1)	2009/10 **Forecast** (CGM08-1)	2010/11 **Forecast** (CGM08-1)	2011/12 **Forecast** (CGM08-1)
Interest on Long Term Debt	13,760	14,987	15,342	15,342
Interest on Short Term Debt	4,384	912	1,719	3,530
Total Interest on Debt	18,144	15,899	17,061	18,872
Add:				
Provincial Guarantee Fee	3,282	3,285	3,633	3,674
Amortization of Debt Discounts	1,256	1,262	298	318
Interest on Common Assets	2,562	2,677	2,839	3,244
Interest on Inventory	24	25	27	29
Total Additions	7,124	7,249	6,797	7,265
Deduct:				
Capitalized Interest	(214)	(212)	(127)	(127)
Carrying Costs on Deferred Taxes	(2,996)	(2,850)	(2,704)	(2,557)
Carrying Costs on Purchased Gas Variance Account	109	809	(31)	-
Other	58	97	21	(77)
Total Deductions	(3,043)	(2,156)	(2,841)	(2,762)
Total Finance Expense	**22,225**	**20,992**	**21,017**	**23,375**

	2008/09 Difference	2009/10 Difference	2010/11 Difference	2011/12 Difference
Interest on Long Term Debt	(7)	(682)	(1,200)	(952)
Interest on Short Term Debt	(1,626)	(570)	(1,588)	(3,428)
Total Interest on Debt	(1,633)	(1,252)	(2,787)	(4,380)
Add:				
Provincial Guarantee Fee	-	97	(491)	(571)
Amortization of Debt Discounts	-	-	-	-
Interest on Common Assets	(178)	(279)	(34)	(541)
Interest on Inventory	1	79	66	75
Total Additions	(177)	(103)	(460)	(1,037)
Deduct:				
Capitalized Interest	21	78	(15)	(83)
Carrying Costs on Deferred Taxes	-	-	-	-
Carrying Costs on Purchased Gas Variance Account	(267)	(852)	16	262
Other	(10)	57	117	334
Total Deductions	(256)	(717)	118	514
Total Finance Expense	**(2,067)**	**(2,071)**	**(3,129)**	**(4,904)**

Centra Gas Manitoba Inc.
2013/14 General Rate Application

PUB/Centra I - 42(c)
Attachment

Summary of Total Finance Expense (CGM12) - Forecast to March 31, 2022
In Thousands for the Years Ending

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Interest on Long Term Debt	13,336	12,544	13,527	14,412	15,176	16,179	17,190	17,720	18,250	19,310
Interest on Short Term Debt	22	284	250	301	639	569	323	426	546	310
Total Interest on Debt	13,358	12,828	13,777	14,713	15,815	16,748	17,513	18,146	18,796	19,620
Add:										
Provincial Guarantee Fee	3,048	2,975	3,341	3,341	3,485	3,695	3,828	3,952	4,079	4,212
Amortization of Debt Discounts	167	-	-	-	-	-	-	-	-	-
Interest on Common Assets	2,896	3,020	3,139	3,196	3,253	3,315	3,378	3,442	3,508	3,574
Interest on Inventory	148	151	154	157	160	163	166	169	172	175
Total Additions	6,259	6,146	6,634	6,694	6,898	7,173	7,372	7,563	7,759	7,961
Deduct:										
Capitalized Interest	(174)	(113)	(137)	(135)	(129)	(128)	(127)	(131)	(140)	(133)
Carrying Costs on Deferred Taxes	(2,412)	(2,265)	-	-	-	-	-	-	-	-
Carrying Costs on Purchased Gas Variance Account	584	332	(153)	-	-	-	-	-	-	-
Other	286	368	556	747	803	745	671	589	500	409
Total Deductions	(1,716)	(1,678)	266	612	674	617	544	458	360	276
Total Finance Expense	**17,901**	**17,296**	**20,677**	**22,019**	**23,387**	**24,538**	**25,429**	**26,167**	**26,915**	**27,857**

PUB/CENTRA I-46

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Appendix 5.4 Note 9 Long Term Debt**

Please indicate the weighted average yield rate that 2013 debt repayments were rolled over at.

ANSWER:

Centra debt issue CG1 for $62.67 million with a weighted average yield rate of 5.98% matured on September 18, 2012 and was refinanced with the following long term debt issues:

CG15	$20 million	3.178%
CG16	$20 million	3.281%
CG17	$20 million	3.413%

The weighted average yield rate for CG15-17 is 3.291%.

TERM SHEET

Series CG15
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$20,000,000 CAD**
Issue Date	September 18, 2012
Maturity Date	September 18, 2022
Term to Maturity	10 Years
Coupon Rate	3.178%
Yield Rate	3.178%
Interest Payable	March 18 & September 18

NOTE: Long term inter-company advance Series CG15 was issued to Centra Gas Manitoba by the MHEB in order to partially refinance long term inter-company advance Series CG1 that had a September 18, 2012 maturity of $62,670,600. The interest rate was assigned based on MHEB Series C129. Interest will accrue from the date of issuance September 18, 2012 with the first interest payment occurring March 18, 2013.

TERM SHEET

Series CG16
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$20,000,000 CAD**
Issue Date	September 18, 2012
Maturity Date	September 18, 2033
Term to Maturity	21 Years
Coupon Rate	3.281%
Yield Rate	3.281%
Interest Payable	March 18 & September 18

NOTE: Long term inter-company advance Series CG16 was issued to Centra Gas Manitoba by the MHEB in order to partially refinance long term inter-company advance Series CG1 that had a September 18, 2012 maturity of $62,670,600. The interest rate was assigned based on MHEB Series FN-3. Interest will accrue from the date of issuance September 18, 2012 with the first interest payment occurring March 18, 2013.

TERM SHEET

Series CG17
Intercompany Advance from the Manitoba Hydro-Electric Board (MHEB)

Principal	**$20,000,000 CAD**
Issue Date	September 18, 2012
Maturity Date	September 18, 2042
Term to Maturity	30 Years
Coupon Rate	3.413%
Yield Rate	3.413%
Interest Payable	March 18 & September 18

NOTE: Long term inter-company advance Series CG17 was issued to Centra Gas Manitoba by the MHEB in order to partially refinance long term inter-company advance Series CG1 that had a September 18, 2012 maturity of $62,670,600. The interest rate was assigned based on MHEB Series GA. Interest will accrue from the date of issuance September 18, 2012 with the first interest payment occurring March 18, 2013.

PUB/CENTRA I-43

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Pages 20 and 21 of 30 - Debt Issues**

c) Please provide a schedule of the long term debt from 2006/07 through 20013/14.

ANSWER:

Please find attached a continuity schedule of long term debt from 2006/07 through 2013/14.

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2012/13 General Rate Application

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Long Term Debt Continuity Schedule

($000's)

	2006	2006/07				2007/08			2008/09			2009/10		
	Ending Balance	Serial Redemption	Maturities	New Advances	Ending Balance	Serial Redemption	Maturities	Ending Balance	Serial Redemption	Maturities	Ending Balance	Maturities	New Advances	Ending Balance
MH Advances														
CG1	62,671				62,671			62,671			62,671			62,671
CG2	6,520		(6,520)		-			-			-			-
CG3	48,525		(48,525)		-			-			-			-
CG4	24,856	(2,260)			22,597	(2,260)		20,337	(2,260)		18,077	(18,077)		-
CG5	75,000				75,000			75,000			75,000	(75,000)		-
CG7				50,000	50,000			50,000			50,000			50,000
CG8	30,000				30,000			30,000			30,000			30,000
CG9													30,000	30,000
CG10													35,000	35,000
CG11													30,000	30,000
CG12													10,000	10,000
CG13													20,000	20,000
CG14													30,000	30,000
CG15														
CG16														
CG17														
Total	**247,572**	**(2,260)**	**(55,045)**	**50,000**	**240,267**	**(2,260)**	**-**	**238,007**	**(2,260)**		**235,748**	**(93,077)**		**297,671**

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Long Term Debt Continuity Schedule

($000's)

	2010	2010/11			2011/12			2012/13			2013/14		
	Ending Balance	Maturities	New Advances	Ending Balance	Maturities	New Advances	Ending Balance	Maturities	New Advances	Ending Balance	Maturities	New Advances	Ending Balance
MH Advances													
CG1	62,671			62,671			62,671	(62,671)		-			-
CG2	-			-			-			-			-
CG3	-			-			-			-			-
CG4	-			-			-			-			-
CG5	-			-			-			-			-
CG7	50,000			50,000			50,000			50,000			50,000
CG8	30,000			30,000			30,000			30,000			30,000
CG9	30,000			30,000			30,000			30,000			30,000
CG10	35,000			35,000			35,000			35,000			35,000
CG11	30,000			30,000			30,000			30,000			30,000
CG12	10,000			10,000			10,000			10,000			10,000
CG13	20,000			20,000			20,000			20,000			20,000
CG14	30,000			30,000			30,000			30,000			30,000
CG15									20,000	20,000			20,000
CG16									20,000	20,000			20,000
CG17									20,000	20,000			20,000
New Debt - March 2014												30,000	30,000
Total	**297,671**	**-**		**297,671**	**-**	**-**	**297,671**	**(62,671)**		**295,000**	**-**	**30,000**	**325,000**

51.

M A N I T O B A	**Order No. 128/09**
THE PUBLIC UTILITIES BOARD ACT	**September 16, 2009**

BEFORE: Graham Lane, CA, Chairman
Len Evans, LL.D., Member
Monica Girouard, Member

CENTRA GAS MANITOBA INC. 2009/10 AND 2010/11 GENERAL RATE APPLICATION AND OTHER MATTERS

5.0 IT IS THEREFORE RECOMMENDED THAT:

1. Centra continue to be cognizant of the costs for DSM that are built into rates for the various rate classes, and ensure that the incentives for Power Smart programs are properly allocated to the customer classes that are receiving them;
2. Centra favour expenditures from the AEF that are directed or at least prioritized towards non-government owned properties;
3. Centra prepare and release more Fixed Rate Offerings, with adequate volumes so as to disappoint as low a number of prospective customers as possible, as soon as possible to provide choice for consumers when purchasing Primary gas, and that Centra aggressively advertise the availability of its offerings;
4. MH review its current operational practices to ensure that Centra is provided sufficient short-term debt to meet its seasonal operational needs; and
5. Regarding discussions Centra has had with counterparties who expressed interest in managing Centra's supply, storage, and transportation assets, Centra provide detailed information, in confidence if necessary, on the specific contacts that Centra has had with any of these counterparties over the past five years.
6. Centra improve the marketing and reach of its FRP, but failing any demonstrable improvement in the take-up and participation in the FRP, Centra and MH should consider the formation of a separate energy efficiency agency that would be dedicated to the delivery of Centra's DSM and LIEEP programming.

6.0 IT IS THEREFORE ORDERED THAT:

1. Net Plant Additions to Rate Base for 2009/10 and 2010/11, as requested by Centra, BE AND ARE HEREBY APPROVED subject to the impact of Directives set out in this Order;

2. DSM expenditures included in Rate Base as a component of working capital allowance, BE AND ARE HEREBY APPROVED;

3. Centra's Application as filed and subsequently revised BE AND IS HEREBY APPROVED subject to the following:

   a. Finance Expense is adjusted by utilizing short term interest rate forecasts of 0.5% in 2009/10 and 1.0% in 2010/11, and long term interest rate forecasts of 4.0% in 2009/10 and 2010/11;

   b. $3.8 million is included in the revenue requirement for continuing the Furnace Replacement Program (FRP), and is to be funded by the Small General Service class;

   c. The $5 million accounting provision for IFRS and other risks to Centra in the second test year is denied;

   d. Amortization of DSM expenditures (with the exception of the expenditures related to the Furnace Replacement Program, which are to be expenses as incurred) is to be over a 10-year timeframe, consistent with the approach of Manitoba Hydro, on a prospective basis;

   e. Recovery of the majority of the revenue deficiency allocated to the SGS and LGS classes is to be by way of May 1, 2010 increases to the monthly BMC to $14 and $77, per month, respectively;

   f. The Primary Gas Overhead Rate, currently $1.63 per thousand cubic metres of natural gas, is to increase to $\$1.64/10^3m^3$ effective May 1, 2010;

4. The Board directs that Centra continue to fund the FRP in the amount of $3.8 million per year through rates to the SGS class. $3.8 million is to accrue to the FRP account regardless of the weather impact on revenues. The FRP is to continue at this level of funding beyond the test years until such time as Centra receives alternative direction from the Board, and any unspent funds are to accrue interest at Centra's actual short term interest rate;

5. The Board directs Centra to file a semi-annual status update report on the FRP, to begin with a report by December 31, 2009;

6. Centra to develop and file with the Board a revised marketing and promotional plan for the LIEEP and FRP, designed to educate and encourage lower income consumers to participate;

7. Centra is to undertake and file with the Board by December 31, 2009 a demographic study that will assist it in reaching the target demographic for its lower income programs.

8. The Board confirms that Centra is to continue pricing its Fixed Rate Offerings according to the pricing formula approved in Order 156/08, excepting that the Program Cost Rate for all new offerings from this date shall be $0.0262/m^3;

9. Centra to file for the Board's approval, by its next GRA, a revised interest rate forecasting methodology for rate setting purposes incorporating changes recommended by CAC/MSOS' witness Mr. McCormick, as follows:

   a. The use of all forecasts based on comparable average period data basis;

   b. The use and alignment of current date forecasts, excluding stale dated and superseded forecasts;

c. Utilization of forecasted long term interest rates which align with the period in which Centra intends on issuing new or refinancing existing long term debt;
d. A process to retrospectively test the accuracy of forecasters to assess their inclusion in future forecasts;
e. The use of only statistically independent forecasts; and
f. A proposed process to update the forecast in advance of the hearing if warranted.

10. Centra to perform a true-up and adjustment on a quarterly basis to ensure there has been no over- or under-recovery of short-term finance costs charged to Centra from MH;
11. Centra to file on or before March 1, 2010 a terms of reference for a study to review the Integrated Cost Allocation Methodology. The study is to be completed in sufficient time to be incorporated within the corporation's next MH or Centra GRA;
12. Centra to calculate its DSM amortization for 2009/10 and thereafter based on a 10-year amortization period, and record its depreciation and amortization expense for rate setting purposes accordingly;
13. Centra to file a business plan with respect to the AMI project with the Board for its approval by January 15, 2010, and prior to proceeding beyond the pilot project expenditures. The business plan should include an assessment of the economic and non-economic benefits of AMI, including safety-related matters, for both the meter reader and for Centra's customers;
14. Changes to Centra's Terms and Conditions of Service regarding company labour rates for chargeable services BE AND ARE HEREBY APPROVED;
15. Changes to Centra's Terms and Conditions of Service relating to new requirements for Interruptible Service class customers BE AND ARE HEREBY APPROVED;

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			2013				2014				2015
			Q2	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**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.

	Canadian 3 Month T-Bill	**Guarantee Fee**	**MH Canadian Short Term Interest Rate**
2012/13	1.00%	1.00%	2.00%
2013/14	1.30%	1.00%	2.30%
2014/15	2.10%	1.00%	3.10%

The Manitoba Hydro Canadian long term interest rate was calculated by adding the appropriate credit spread to the Canadian 10 year+ bond yield rate and a provincial debt guarantee fee as follows:

	Canadian 10 Year+ Bond Yield	**10 Year+ Credit Spread**	**Guarantee Fee**	**MH Canadian 10 Year+ Long Term Interest Rate**
2012/13	2.15%	1.00%	1.00%	4.15%
2013/14	2.55%	0.75%	1.00%	4.30%
2014/15	3.20%	0.65%	1.00%	4.85%

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.

52.

Please see the following schedule for a breakdown of Depreciation and Amortization.

CENTRA GAS MANITOBA INC. **Schedule 5.7.0**
Depreciation Expense **($000'S)**

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Intangible Assets						
Franchises & Consents	2	2	2	1	1	1
Land Rights	40	50	54	58	59	59
Computer System Development	-	1,395	1,348	626	530	530
Other Distribution Development (SCADA)	-	-	-	-	330	793
	42	1,447	1,404	686	921	1,384
Transmission Plant						
Land	-	-	-	-	-	-
Structures & Improvements - M&R	15	16	17	20	20	20
Structures & Improvements - Other	3	3	3	2	2	2
Mains - Transmission	1,384	1,475	1,520	1,599	1,654	1,668
Measuring & Regulating Equipment	160	181	192	145	146	149
Other Transmission Equipment	0	-	-	-	-	-
Amortization of Customer Contributions: Mains	(250)	(319)	(321)	(331)	(354)	(502)
Amortization of Customer Contributions: Measuring & Regulating Equipment	-	-	-	(0)	(2)	(5)
	1,312	1,356	1,410	1,434	1,466	1,333
Distribution Plant						
Land	-	-	-	-	-	-
Structures & Improvements	43	43	43	28	30	32
Structures & Improvements - M&R	56	56	59	64	66	70
Services	6,298	6,555	6,781	6,167	6,356	6,555
Regulators	1,103	1,150	1,197	1,014	1,050	1,123
Mains - Distribution	2,689	2,771	2,842	2,999	3,151	3,354
Measuring & Reg. Equipment	1,306	1,330	1,339	1,101	1,136	1,171
Telemetry Equipment	202	208	168	199	200	203
Meters	1,467	1,469	1,499	1,708	1,797	1,999
AMR/ERT Modules	9	1	-	-	-	-
Computer Equipment - Hardware			8	37	87	94
Amortization of Customer Contributions: Services	(238)	(272)	(277)	(170)	(170)	(171)
Amortization of Customer Contributions: Regulators	-	-	-	-	-	-
Amortization of Customer Contributions: Mains	(341)	(304)	(308)	(218)	(223)	(229)
Amortization of Customer Contributions: Measuring & Regulating Equipment	(130)	(141)	(141)	(90)	(91)	(91)
Amortization of Customer Contributions: Meters	(17)	(17)	(14)	(2)	(2)	(2)
	12,448	12,850	13,195	12,836	13,387	14,108
General Plant						
Land	-	-	-	-	-	-
Structures & Improvements	179	178	161	137	137	137
Leasehold Improvements	125	-	-	-	-	-
Office Furniture & Equipment	73	73	42	53	30	24
Computer Equipment - Hardware	1	-	-	-	-	-
Computer System Development	1,582	-	-	-	-	-
Transportation Equipment	-	-	-	138	143	26
Heavy Work Equipment	6	6	6	-	-	-
Tools & Work Equipment	195	195	195	183	136	119
Communication Struct.& Equip.	96	27	2	-	-	-
Other General Equipment	8	-	-	-	-	-
	2,263	479	406	511	446	306
Depreciation on Common Assets	3,698	3,709	3,810	4,049	4,407	4,621
Other	1,125	769	1,185	751	751	1,235
Investment in Demand Side Management	4,013	3,087	4,181	5,234	6,264	7,198
Deferred Asset Amortization	5,139	3,857	5,366	5,985	7,015	8,433
Other						
Leasehold Improvements	(10)	616	-	-	-	-
Amount transferred to Common Asset Pool	10	(616)	-	-	-	-
Target Adjustment	-	-	-	-	(22)	(95)
	-	-	-	-	(22)	(95)
Depreciation & Amortization Expense	24,901	23,697	25,591	25,501	27,620	30,091
Year over year $ change		(1,204)	1,894	(90)	2,119	2,470
Year over year % change		-4.8%	8.0%	-0.4%	8.3%	8.9%

Common assets are those fixed assets including administrative facilities, office furniture and equipment, computer systems, tools, work equipment, and vehicles that are used to support both gas and electric operations. The interest, depreciation, and other costs related to the ownership and operation of these assets are applied and allocated to gas and electric operations in accordance with the integrated cost allocation methodology.

DEPRECIATION RATES & DEPRECIATION STUDY

Depreciation expense is recognized on a straight-line basis over the estimated remaining service life of assets, based upon depreciation studies conducted periodically (typically every 5 years) by the Corporation. The last depreciation study for Centra Gas Manitoba Inc. ("Centra") was completed in July 2006 with the resulting depreciation rates being implemented effective April 1, 2007.

In addition to the normal update of service lives, this depreciation study also involved an assessment of International Financial Reporting Standards ("IFRS") compliant depreciation practices and methodologies given that Centra will be required to implement IFRS compliant depreciation rates effective April 1, 2014.

As with previous depreciation studies, an external consultant, Gannett Fleming, Inc., was engaged to review Centra's current depreciation practices, to provide advice on any changes necessary for compliance with IFRS, and to develop IFRS compliant depreciation rates. A depreciation study involves an analysis of financial asset addition and retirement activity to determine a statistical estimate of the average service life for each depreciable component; a peer review; and discussions with operational and engineering staff to identify company specific factors impacting the service lives of each component, such as changes in use or technology that could limit the usefulness of historical transactions in predicting current useful lives, and differences in use and circumstances that could impact the comparability to peer companies. The depreciation consultant considers each of these factors in determining an appropriate average service life and depreciation curve to be used for each depreciable component. Please see the IFRS compliant Depreciation Study for information about the scope and basis for the study, as well as the methods used in this study.

The depreciation study was initiated in 2009 and completed in October 2011 and is based on depreciable assets in service as of March 31, 2010. The implementation of the depreciation rates resulting from the recent study will be accomplished in two phases. In the first phase, Centra updated services lives effective April 1, 2011. In the second phase, Centra will implement IFRS compliant depreciation rates effective April 1, 2014 which will include a change in the depreciation methodology to the Equal Life Group (ELG) and the removal of asset retirement costs from depreciation rates.

A summary of the depreciation rates effective April 1, 2007 as compared to the depreciation rates effective April 1, 2011 and April 1, 2014 may be found in the table on page 5, followed by a letter from Gannett Fleming, Inc. containing the depreciation rates to be used under Generally Accepted Accounting Principles, and by the full IFRS compliant Depreciation Study.

The following table provides a summary of the estimated changes to depreciation expense for gas operations for the 3 year period between 2013 and 2015:

	Depreciation Expense ($ 000's)		
	2013	**2014**	**2015**
Change in Service Life - PP&E (Net of Contributions)	(1,094)	(1,180)	(1,231)
Change in methodology (ELG)			2,309
Removal of Asset Retirement Costs from Depreciation			(4,897)
Net Impact	**(1,094)**	**(1,180)**	**(3,819)**

The significant changes in the depreciation study are discussed in the sections below.

<u>Componentization & Change in Service Lives</u>

In preparation for conversion to IFRS, Centra undertook a comprehensive review of existing depreciable component groupings to determine whether IFRS requirements were met. As a result of this review, it was determined that no new components are required for Centra in order to comply with IFRS. Centra uses the standard asset groupings recommended by the Canadian Gas Association, which are generally accepted as being IFRS compliant in other Canadian gas utilities.

Life extensions were recommended by the consultant for several accounts in consideration of the following factors:

a) Statistical evidence that Centra has been achieving a longer service life than previously estimated as evidenced by lower level of ongoing retirement activity than expected;
b) Industry comparative data; and
c) Discussions with Centra personnel. Operational management have indicated that Centra experiences less incidence of failure than is typical in the industry due to superior cathodic protection and the lack of any significant amount of the early generation uncertified plastic pipe that has been subject to premature failure in other Western Canadian natural gas distribution utilities.

The impact of these changes for Centra was a decrease to depreciation expense (net of contributions) of $0.874 million in 2011/12 with estimated decreases of $1.094 million in 2012/13, $1.180 million in 2013/14 and $1.231 million in 2014/15.

Change in methodology to Equal Life Group

There are two main methods used by utilities for calculating group depreciation, the Average Service Life (ASL) procedure and the Equal Life Group (ELG) procedure.

IFRS requires that any gains and losses on the disposal/retirement of an asset must be recognized immediately in income. This is different than the current North American regulatory practice of recording gains and losses in accumulated depreciation and this has resulted in a change to the depreciation methodology to better match the recording of depreciation with the actual service life of the underlying assets.

The ASL procedure, which has been used by Centra in the past, calculates depreciation expense based upon the average life of all assets within each class. Although accepted for utility accounting under current Canadian accounting standards, this method is viewed as problematic from an IFRS perspective because, except for those assets which have a life exactly equal to the average service life of that group, assets are being depreciated over a longer or shorter timeframe than their expected service life.

The ELG procedure addresses this issue by developing depreciation rates with specific consideration of the expected retirement pattern for each asset within each class. Every asset in the class is depreciated over its own expected service life and therefore is expected to be fully depreciated (not over or under depreciated) when it is removed from service. The resulting depreciation expense calculations are compliant with IFRS and minimize retirement gains or losses that must be recognized in current income. Centra will be calculating depreciation rates based on ELG methodology effective April 1, 2014.

Because the ELG procedure ensures that assets with a shorter service life than average are fully depreciated at their expected retirement date, there is an earlier recognition of depreciation expense than would be the case under the ASL procedure. The estimated impact of this change for Centra is an increase to depreciation expense of $2.309 million in 2014/15.

Removal of Asset Retirement Costs from Depreciation

IFRS is also much more prescriptive in terms of those items that make up the depreciable cost of assets and does not recognize North American regulatory practices of including the costs of removal of assets in depreciation rates unless there is a legal or constructive obligation to remove such assets (in which case an asset retirement obligation is recorded). As such, Centra will be eliminating this practice and removing asset retirement costs from its depreciation rates effective April 1, 2014.

The estimated impact of this change for Centra is a decrease to depreciation expense of $4.897 million in 2014/15.

Please see the following table for the depreciation rates for Centra.

Depreciable Group	Effective April 1, 2007	Effective April 1, 2011	Effective April 1, 2014
FRANCHISES & CONSENTS	5.56	5.56	5.56
TRANSMISSION			
Land Rights	1.23	1.29	1.38
Structures & Improvements - M&R	1.64	1.96	1.84
Structures & Improvements - Other	3.51	2.32	2.06
Mains	1.73	1.74	1.55
Measuring & Regulating Equipment	2.62	1.93	1.99
Regulating Station Electronic Equipment		6.67	6.67
Other - Transmission	2.50	2.50	2.50
DISTRIBUTION			
Land Rights	1.28	1.29	1.38
Structures & Improvements	3.19	2.10	2.09
Structures & Improvements - M&R	1.56	1.58	1.83
Services	3.27	2.89	1.90
Regulators & Meter Installations	2.62	2.13	2.25
Mains	1.80	1.84	1.51
Measuring & Regulating Equipment	4.04	3.27	2.91
Telemetry Equipment	5.59	5.00	5.01
Regulating Station Electronic Equipment		6.67	6.67
Meters	3.76	4.15	4.87
AMR / ERT Modules	10.00	10.00	10.00
Computer Hardware Equipment - EMS/SCADA		20.00	20.00
Computer System Development - EMS/SCADA		20.00	20.00
GENERAL PLANT			
Structures & Improvements	1.95	1.50	2.57
Office Furniture & Equipment	6.67	6.67	6.67
Computer System Development	10.00	10.00	10.00
Transportation Equipment	6.14	13.94	13.59
Heavy Work Equipment	5.34	-	-
Tools & Work Equipment	6.67	6.67	6.67
COMPOSITE (WEIGHTED AVERAGE) RATE	**2.80**	**2.62**	**2.23**

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-37(b)**
Utility Net Plant and Depreciation
2012/13 Forecast **($000'S)**

	Cost Mar 31/13	Accumulated Depreciation Mar 31/13	Net Book Value Mar 31/13	Depreciation Rate %	Depreciation Expense 2012/13
Intangible Plant					
Franchises & Consents	22	12	11	5.56 %	1
Land Rights					
Transmission	3,584	677	2,906	1.29 %	46
Distribution	1,015	147	868	1.29 %	13
Computer System Development	5,304	3,801	1,503	10.00 %	530
Dist. Computer System Development (SCADA)	3,461	330	3,130	20.00 %	330
Transmission Plant					
Land	791	-	791	0.00 %	-
Structures & Improvements - M&R	1,040	538	502	1.96 %	20
Structures & Improvements	76	58	18	2.32 %	2
Mains - Transmission	96,004	25,640	70,364	1.74 %	1,654
Measuring & Regulating Equipment	7,625	2,557	5,068	1.93 %	146
Other Transmission Equipment	-	-	-	2.50 %	-
Distribution Plant					
Land	1,091	-	1,091	0.00 %	-
Structures & Improvements	1,544	771	773	2.10 %	30
Structures & Improvements - M&R	4,295	1,318	2,977	1.58 %	66
Services	222,094	82,129	139,965	2.89 %	6,347
Regulators	50,058	20,048	30,010	2.13 %	1,049
Mains - Distribution	177,385	61,877	115,509	1.84 %	3,146
Measuring & Reg. Equipment	35,086	17,235	17,852	3.27 %	1,134
Telemetry Equipment	4,018	3,311	708	5.00 %	200
Meters	41,882	7,706	34,175	4.15 %	1,794
AMR/ERT Modules	-	-	-	10.00 %	-
Computer Equipment - Hardware (SCADA)	469	132	337	20.00 %	87
General Plant					
Land	137	-	137	0.00 %	-
Structures & Improvements	9,145	5,948	3,196	1.50 %	137
Office Furniture & Equipment	382	300	82	6.67 %	30
Transportation Equipment	556	543	13	13.94 %	143
Heavy Work Equipment	362	373	(12)	0.00 %	-
Tools & Work Equipment	1,943	1,644	299	6.67 %	136
Other General Equipment	393	-	393	0.00 %	-
Total Gross Plant	669,763	237,097	432,666		17,042

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-37(b)**
Utility Net Plant and Depreciation
2013/14 Forecast **($000'S)**

	Cost Mar 31/14	Accumulated Depreciation Mar 31/14	Net Book Value Mar 31/14	Depreciation Rate %	Depreciation Expense 2013/14
Intangible Plant					
Franchises & Consents	22	13	9	5.56 %	1
Land Rights					
Transmission	3,584	724	2,860	1.29 %	46
Distribution	1,015	160	855	1.29 %	13
Computer System Development	5,304	4,331	974	10.00 %	530
Dist. Computer System Development (SCADA)	3,461	1,123	2,338	20.00 %	793
Transmission Plant					
Land	791	-	791	0.00 %	-
Structures & Improvements - M&R	1,040	559	482	1.96 %	20
Structures & Improvements	76	59	17	2.32 %	2
Mains - Transmission	96,527	27,308	69,218	1.74 %	1,668
Measuring & Regulating Equipment	7,780	2,676	5,103	1.93 %	149
Other Transmission Equipment	-	-	-	2.50 %	-
Distribution Plant					
Land	1,091	-	1,091	0.00 %	-
Structures & Improvements	1,544	804	740	2.10 %	32
Structures & Improvements - M&R	4,558	1,376	3,181	1.58 %	70
Services	228,317	85,306	143,011	2.89 %	6,555
Regulators	55,445	21,170	34,274	2.13 %	1,123
Mains - Distribution	186,692	64,718	121,974	1.84 %	3,259
Measuring & Reg. Equipment	36,175	18,334	17,841	3.27 %	1,171
Telemetry Equipment	4,059	3,495	564	5.00 %	203
Meters	43,609	6,505	37,103	4.15 %	1,999
AMR/ERT Modules	-	-	-	10.00 %	-
Computer Equipment - Hardware (SCADA)	469	226	243	20.00 %	94
General Plant					
Land	137	-	137	0.00 %	-
Structures & Improvements	9,145	6,086	3,059	1.50 %	137
Office Furniture & Equipment	266	208	58	6.67 %	24
Transportation Equipment	-	13	(13)	13.94 %	26
Heavy Work Equipment	362	373	(12)	0.00 %	-
Tools & Work Equipment	1,513	1,332	180	6.67 %	119
Other General Equipment	393	-	393	0.00 %	-
Total Gross Plant	693,372	246,900	446,472		18,036

PUB/CENTRA I-37

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 24 of 30 Schedule 5.7.0**

c) Please provide a comparison, by component, of the depreciation expense and depreciation rates between the rates implemented in 2007 and the rates implemented April 1, 2011 for 2011/12, 2012/13, and 2013/14.

ANSWER:

The following schedules provide a calculation of the impact, by component, of the change in depreciation rates for the 2011/12, 2012/13 and 2013/14 fiscal years.

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-37(c)**
Utility Plant Depreciation Expense
2011/12 Actual **($000'S)**

	Depreciation Rates Implemented April 1, 2007		Depreciation Rates Implemented April 1, 2011		Difference Resulting From Change in Depreciation Rates	
	Rate %	Expense 2011/12	Rate %	Expense 2011/12	Rate %	Expense 2011/12
Intangible Plant						
Franchises & Consents	5.56 %	1	5.56 %	1	-	-
Land Rights					-	
Transmission	1.23 %	44	1.29 %	46	0.06 %	2
Distribution	1.28 %	12	1.29 %	12	0.01 %	-
Computer System Development	10.00 %	626	10.00 %	626	-	-
Dist. Computer System Development (SCADA)	20.00 %	-	20.00 %	-	-	-
Transmission Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements - M&R	1.64 %	17	1.96 %	20	0.32 %	3
Structures & Improvements	3.51 %	3	2.32 %	2	-1.19 %	(1)
Mains - Transmission	1.73 %	1,590	1.74 %	1,599	0.01 %	9
Measuring & Regulating Equipment	2.62 %	197	1.93 %	145	-0.69 %	(52)
Other Transmission Equipment	2.50 %	-	2.50 %	-	-	-
Distribution Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements	3.19 %	43	2.10 %	28	-1.09 %	(15)
Structures & Improvements - M&R	1.56 %	63	1.58 %	64	0.02 %	1
Services	3.27 %	6,978	2.89 %	6,167	-0.38 %	(811)
Regulators	2.62 %	1,247	2.13 %	1,014	-0.49 %	(233)
Mains - Distribution	1.80 %	2,934	1.84 %	2,999	0.04 %	65
Measuring & Reg. Equipment	4.04 %	1,360	3.27 %	1,101	-0.77 %	(259)
Telemetry Equipment	5.59 %	222	5.00 %	199	-0.59 %	(23)
Meters	3.76 %	1,548	4.15 %	1,708	0.39 %	160
AMR/ERT Modules	10.00 %	-	10.00 %	-	-	-
Computer Equipment - Hardware (SCADA)	20.00 %	37	20.00 %	37	-	-
General Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements	1.95 %	178	1.50 %	137	-0.45 %	(41)
Office Furniture & Equipment	6.67 %	53	6.67 %	53	-	-
Transportation Equipment	6.14 %	61	13.94 %	138	7.80 %	77
Heavy Work Equipment	5.34 %	-	0.00 %	-	-5.34 %	-
Tools & Work Equipment	6.67 %	183	6.67 %	183	-	-
Other General Equipment	0.00 %	-	0.00 %	-	-	-
Total Gross Plant		17,397		16,280		(1,117)

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-37(c)**
Utility Plant Depreciation Expense
2012/13 Forecast **($000'S)**

	Depreciation Rates Implemented April 1, 2007		Depreciation Rates Implemented April 1, 2011		Difference Resulting From Change in Depreciation Rates	
	Rate %	Expense 2012/13	Rate %	Expense 2012/13	Rate %	Expense 2012/13
Intangible Plant						
Franchises & Consents	5.56 %	1	5.56 %	1	-	-
Land Rights						
Transmission	1.23 %	44	1.29 %	46	0.06 %	2
Distribution	1.28 %	13	1.29 %	13	0.01 %	-
Computer System Development	10.00 %	530	10.00 %	530	-	-
Dist. Computer System Development (SCADA)	20.00 %	330	20.00 %	330	-	-
Transmission Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements - M&R	1.64 %	17	1.96 %	20	0.32 %	3
Structures & Improvements	3.51 %	3	2.32 %	2	-1.19 %	(1)
Mains - Transmission	1.73 %	1,644	1.74 %	1,654	0.01 %	10
Measuring & Regulating Equipment	2.62 %	198	1.93 %	146	-0.69 %	(52)
Other Transmission Equipment	2.50 %	-	2.50 %	-	-	-
Distribution Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements	3.19 %	45	2.10 %	30	-1.09 %	(15)
Structures & Improvements - M&R	1.56 %	65	1.58 %	66	0.02 %	1
Services	3.27 %	7,182	2.89 %	6,347	-0.38 %	(835)
Regulators	2.62 %	1,290	2.13 %	1,049	-0.49 %	(241)
Mains - Distribution	1.80 %	3,078	1.84 %	3,146	0.04 %	68
Measuring & Reg. Equipment	4.04 %	1,401	3.27 %	1,134	-0.77 %	(267)
Telemetry Equipment	5.59 %	224	5.00 %	200	-0.59 %	(24)
Meters	3.76 %	1,626	4.15 %	1,794	0.39 %	168
AMR/ERT Modules	10.00 %	-	10.00 %	-	-	-
Computer Equipment - Hardware (SCADA)	20.00 %	87	20.00 %	87	-	-
General Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements	1.95 %	178	1.50 %	137	-0.45 %	(41)
Office Furniture & Equipment	6.67 %	30	6.67 %	30	-	-
Transportation Equipment	6.14 %	63	13.94 %	143	7.80 %	80
Heavy Work Equipment	5.34 %	-	0.00 %	-	-5.34 %	-
Tools & Work Equipment	6.67 %	136	6.67 %	136	-	-
Other General Equipment	0.00 %	-	0.00 %	-	-	-
Total Gross Plant		18,185		17,042		(1,143)

CENTRA GAS MANITOBA INC. **PUB/CENTRA I-37(c)**
Utility Plant Depreciation Expense
2013/14 Forecast **($000'S)**

	Depreciation Rates Implemented April 1, 2007		Depreciation Rates Implemented April 1, 2011		Difference Resulting From Change in Depreciation Rates	
	Rate %	Expense 2013/14	Rate %	Expense 2013/14	Rate %	Expense 2013/14
Intangible Plant						
Franchises & Consents	5.56 %	1	5.56 %	1	-	-
Land Rights					-	
Transmission	1.23 %	44	1.29 %	46	0.06 %	2
Distribution	1.28 %	13	1.29 %	13	0.01 %	-
Computer System Development	10.00 %	530	10.00 %	530	-	-
Dist. Computer System Development (SCADA)	20.00 %	793	20.00 %	793	-	-
Transmission Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements - M&R	1.64 %	17	1.96 %	20	0.32 %	3
Structures & Improvements	3.51 %	3	2.32 %	2	-1.19 %	(1)
Mains - Transmission	1.73 %	1,659	1.74 %	1,668	0.01 %	9
Measuring & Regulating Equipment	2.62 %	203	1.93 %	149	-0.69 %	(54)
Other Transmission Equipment	2.50 %	-	2.50 %	-	-	-
Distribution Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements	3.19 %	48	2.10 %	32	-1.09 %	(16)
Structures & Improvements - M&R	1.56 %	68	1.58 %	70	0.02 %	2
Services	3.27 %	7,416	2.89 %	6,555	-0.38 %	(861)
Regulators	2.62 %	1,380	2.13 %	1,123	-0.49 %	(257)
Mains - Distribution	1.80 %	3,187	1.84 %	3,259	0.04 %	72
Measuring & Reg. Equipment	4.04 %	1,446	3.27 %	1,171	-0.77 %	(275)
Telemetry Equipment	5.59 %	225	5.00 %	203	-0.59 %	(22)
Meters	3.76 %	1,811	4.15 %	1,999	0.39 %	188
AMR/ERT Modules	10.00 %	-	10.00 %	-	-	-
Computer Equipment - Hardware (SCADA)	20.00 %	94	20.00 %	94	-	-
General Plant						
Land	0.00 %	-	0.00 %	-	-	-
Structures & Improvements	1.95 %	178	1.50 %	137	-0.45 %	(41)
Office Furniture & Equipment	6.67 %	24	6.67 %	24	-	-
Transportation Equipment	6.14 %	10	13.94 %	26	7.80 %	16
Heavy Work Equipment	5.34 %	-	0.00 %	-	-5.34 %	-
Tools & Work Equipment	6.67 %	119	6.67 %	119	-	-
Other General Equipment	0.00 %	-	0.00 %	-	-	-
Total Gross Plant		19,269		18,036		(1,233)

PUB/CENTRA I-37

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 24 of 30 Schedule 5.7.0**

d) Please identify all the changes made to component accounts since the last depreciation study and explain why these changes were made.

ANSWER:

For the 2010 Depreciation Study, the following four new accounts were added in response to changing business requirements, which will be used on a go forward basis. The regulating station electronic equipment accounts were established in recognition of the increasing use of electronic equipment in regulating stations. Electronic equipment has a significantly shorter life and will require earlier replacement than mechanical equipment. The computer hardware and system development accounts were established for the new gas SCADA system.

Transmission:

467.20 Regulating Station Electronic Equipment

Distribution:

477.20 Regulating Station Electronic Equipment

479.10 Computer Hardware Equipment – EMS/SCADA

479.30 Computer System Development – EMS/SCADA

The following amortization method accounts were removed as all assets existing as at the 2005 Depreciation Study became fully depreciated and were retired prior to the 2010 Depreciation Study. These accounts are no longer required by Centra, as all General Plant assets are now acquired by Manitoba Hydro.

General Plant:

482.10 Leasehold Improvements

483.10 Computer Hardware Equipment

483.20 Computer Software

488.00 Communication Structures & Equipment

489.00 Other General Equipment

PUB/CENTRA I-36

Subject: Tab 5: Financial Results & Forecast

Reference: Tab 5 Appendix 5.8 Pages 1 through 5 of 55

Please confirm whether Centra will request approval of depreciation rates based on the ELG methodology and the removal of asset retirement costs prior to the implementation of these rates.

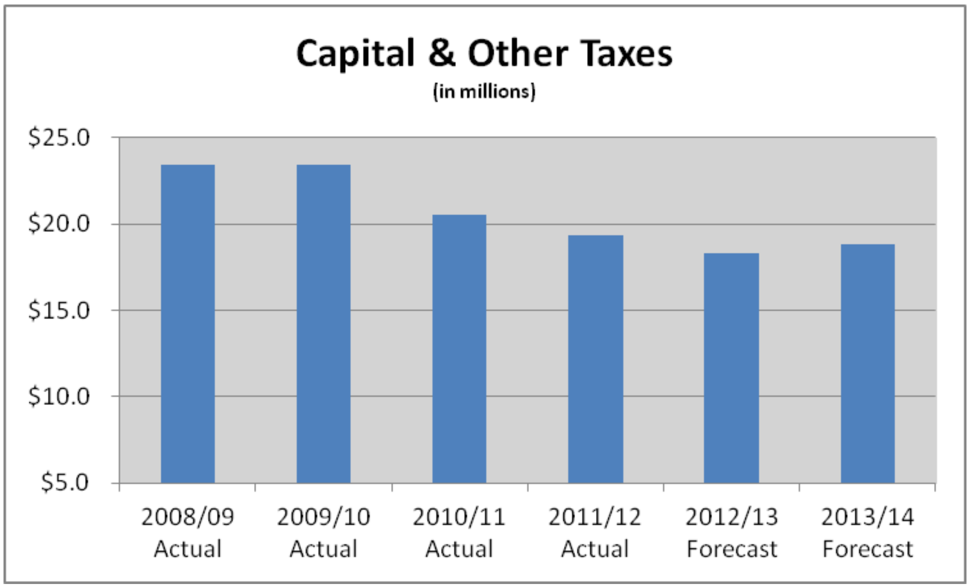
ANSWER:

As indicated in Centra's response to PUB/Centra I-37(a), Centra intends to implement IFRS compliant depreciation rates effective April 1, 2015. In light of the uncertainty that exists with respect to the requirements of a potential interim standard on rate-regulated accounting under IFRS, Centra will apprise the PUB of its plans respecting an application for approval to implement new depreciation rates involving a change in methodology, such as a change to the ELG procedure for group depreciation or the removal of net salvage from depreciation rates, at the appropriate time.

53.

5.8 Capital & Other Taxes

Capital and Other Taxes is comprised of payments made to the Province of Manitoba for capital and payroll taxes, business and property taxes paid to the various municipalities in Manitoba and deferred taxes related to the one-time tax payment made by Centra as a result of the acquisition by Manitoba Hydro in 1999.



Please see the following schedule for a breakdown of Capital & Other Taxes.

CENTRA GAS MANITOBA INC. **Schedule 5.8.0**
Capital and Other Taxes **($000'S)**

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Corporation Capital Tax	2,452	2,377	2,398	2,323	2,304	2,516
Municipal Taxes	15,436	14,836	10,844	11,561	10,861	11,187
Payroll Tax	700	788	802	800	793	807
Taxes on Common Assets	24	380	421	221	160	170
Deferred Income Taxes	4,800	4,654	4,508	4,369	4,216	4,070
City of Winnipeg Audit Settlement		316	1,517			
Total Taxes	23,412	23,351	20,490	19,274	18,334	18,750
Year over year $ change		(61)	(2,861)	(1,216)	(940)	416
Year over year % change		-0.3%	-12.3%	-5.9%	-4.9%	2.3%

Please see the following for a description of Capital & Other Tax components:

The Corporation pays capital tax to the Province of Manitoba at a rate at 0.5% which is applied to the taxable capital of the company.

Municipal taxes are paid based upon the assessed value of property owned by Centra. Taxable property consists mainly of pipelines, services, meters and regulating equipment all of which are assessed based on standard values determined by the Province.

Payroll tax is assessed at a rate of 2.15% on Manitoba Hydro's gross payroll. As Centra has no employees and therefore no direct payroll, this tax amount is an allocation from Manitoba Hydro to Centra based on the relative percentage of activity charges made to Centra.

Taxes on common assets represents Centra's share of property tax paid on administrative facilities.

The City of Winnipeg performed an audit of the company's billing system for the period of August 1, 1999 to December 31, 2010. This audit resulted in a settlement being paid to the City of Winnipeg, which was recorded in 2009/10 and 2010/11.

Deferred income taxes represents the one-time tax liability that was triggered by the acquisition of the company by Manitoba Hydro. In accordance with Order 118/03, Centra deferred the resulting liability and is amortizing the amount over a 30-year period. The following highlights the year over year changes from 2008/09 through 2013/14:

2009/10 Actual vs. 2008/09 Actual

There was no significant change in total taxes paid in 2009/10 compared to 2008/09. The year over year decrease is due to the reduction in property taxes in calendar year 2010 that resulted from the province-wide property reassessment, which is partially offset by the portion of the City of Winnipeg settlement that was recorded in 2009/10, as well as an increase in taxes on common assets.

2010/11 Actual vs. 2009/10 Actual

The 2010/11 decrease is primarily due to reduced property taxes that resulted from the 2010 provincial property reassessment for the full fiscal year. Property taxes paid with respect to calendar year 2010 compared to 2009 decreased by approximately $4.0 million. This was partially offset by the portion of the City of Winnipeg settlement that was recorded in 2010/11.

2011/12 Actual vs. 2010/11 Actual

The 2011/12 decrease was largely due to the fact that the City of Winnipeg settlement amount was recorded in the prior year with no related amount in the current year. This was offset somewhat by an increase in property taxes recorded. Calendar year 2012 was a reassessment year in Manitoba and it was anticipated that total annual property taxes would increase by approximately $1 million, a portion of which was recorded in fiscal 2012.

2012/13 Forecast vs. 2011/12 Actual

The 2012/13 forecast decrease is primarily due to an adjustment to correct for the fact that the 2011/12 actual property taxes were lower than originally recorded.

2013/14 Forecast vs. 2012/13 Forecast

No significant change other than a modest increase due to inflationary impacts on property and payroll taxes.

5.9 Corporate Allocation

The amount of $12.0 million allocated to Centra represents Centra's share of the total annual costs required to amortize the costs incurred by Manitoba Hydro to acquire Centra in 1999.

PUB/CENTRA I-44

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Page 27 of 30 Schedule 5.8.0; Appendix 5.9 - Capital & Other Taxes**

c) Please provide a schedule detailing the Municipal Taxes and payments in lieu of municipal tax by municipality for each of the years 2009/10 through 2013/14.

ANSWER:

Please see the following schedule showing the actual municipal taxes paid for the calendar years 2009 through to 2012.

Municipal tax payments are made on a calendar year basis and appropriate accruals are then made to record fiscal year expenses. Tax bills for 2013, which will be paid in the 2013/14 fiscal year, have not yet been received. Municipal tax payments are not forecasted on a municipality by municipality basis. Therefore a detailed comparison by municipality cannot be provided for 2013/14.

($000's)	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual
RM of Alexander	$ 1	$ 1	$ 1	$ 1
Town of Altona	48	36	36	31
Town of Arborg	9	7	8	7
Rm of Archie	12	14	14	15
RM of Arthur	10	12	13	13
Town of Beausejour	41	26	28	24
RM of Bifrost	40	46	47	48
Rm of Binscarth	9	7	7	6
RM of Blanshard	10	10	10	10
Town of Boissevain	17	14	15	12
City of Brandon	641	476	499	467
RM of Brenda	17	13	13	13
RM of Brokenhead	52	46	48	56
RM of Cameron	24	35	35	36
Town of Carberry	22	15	16	13
Town of Carmen	43	33	33	29
RM of Cartier	25	35	29	32
RM of Cornwallis	96	93	95	96
Rm of Daly	14	15	15	16
Town of Dauphin	174	134	135	118
RM of DeSalaberry	56	54	55	51
Town of Deloraine	20	16	16	15
Rm of Dufferin	58	67	66	67
Rm of Dunnottar	23	16	16	15
RM of East St. Paul	157	111	114	108
Village of Elkhorn	12	10	10	8
RM of Ellice	39	42	46	53
RM of Elton	169	216	224	226
Town of Emerson	19	19	21	19
RM of Franklin	54	58	60	61
RM of Gilbert Plains	54	62	61	59
RM of Gimli	112	97	98	96
Town of Gladstone	13	12	12	9
RM of Glenwood	35	38	38	40
RM of Grandview	71	75	78	77
Town of Gretna	9	7	7	6
RM of Grey	72	84	87	86
Town of Hamiota	43	40	42	38
RM of Hanover	300	267	321	294
Town of Hartney	12	9	9	8

($000's)	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual
RM of Headingly	46	35	36	31
Town of Killarney	49	48	50	60
RM of La Broquerie	151	143	144	131
RM of Langford	16	17	18	17
RM of Macdonald	175	163	169	169
Town of MacGregor	13	9	9	8
Town of Melita	21	20	20	16
RM of Miniota	23	26	26	27
Town of Minnedosa	66	54	55	51
RM of Minto	0	0	0	0
RM of Montcalm	66	72	75	69
RM of Mossomin	3	3	3	3
Town of Morden	95	63	68	62
RM of Morris	39	42	40	34
Town of Morris	43	32	33	28
RM of Morton	49	60	61	59
Town of Neepawa	68	50	50	45
Town of Niverville	32	23	23	22
RM of North Cypress	43	49	52	50
RM of North Norfolk	61	64	67	62
RM of Oakland	19	21	22	24
RM of Odanah	55	61	64	66
RM of Pipestone	17	19	19	19
Town of Plum Coulee	14	10	10	9
RM of Portage	123	126	129	129
Town of Portage la Prairie	220	175	181	175
RM of Reynolds	4	4	4	3
RM of Rhineland	49	53	55	56
RM of Richot	139	126	130	122
Town of Rivers	21	15	14	11
Village of Riverton	8	7	7	7
Town of Roblin	34	26	26	22
RM of Rockwood	82	76	78	75
RM of Roland	38	52	54	53
RM of Rosser	26	27	27	27
RM of Russell	91	97	97	105
City of Selkirk	155	116	117	107
RM of Shell River	16	17	18	17
RM of Shellmouth-Boulton	59	69	68	72
RM of Shoal Lake	23	25	24	21

($000's)	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual
Town of Souris	31	23	24	21
RM of South Cypress	1	1	1	0
RM of St Andrews	223	186	193	186
Village of St. Claude	14	12	13	11
RM of St. Clements	206	178	182	176
Village of St Lazare	9	8	8	8
Village of St Pierre	12	8	8	7
Town of Ste Anne	46	52	53	51
RM of Springfield	215	192	207	195
RM of Stanley	65	74	72	71
City of Steinbach	144	104	108	96
Town of Stonewall	47	29	30	27
RM of Tache	149	126	130	123
Town of Teulon	11	9	9	8
Town of Virden	51	36	37	34
RM of Wallace	74	80	85	85
RM of West St. Paul	75	51	54	51
RM of Westbourne	64	72	71	67
RM of Whitewater	21	27	27	28
RM of Winchester	12	14	14	15
City of Winkler	104	80	82	72
City of Winnipeg	8,809	5,597	5,497	5,137
Town of Winnipeg Beach	29	21	21	19
RM of Woodlands	20	20	21	20
	$ 15,320	$ 11,463	$ 11,562	$ 10,950

CENTRA GAS MANITOBA INC. **Schedule 4.11.0**

Capital and Other Taxes - 2006/07 to 2010/11

($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]
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	2,711	2,762
Capital & Other Taxes	17,156	18,075	18,523	19,047	19,426
Income Taxes(1)	5,092	4,946	4,800	4,654	4,508
Total Taxes	22,248	23,021	23,323	23,701	23,934

(1) Calculation of Income Taxes

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

PUB/CENTRA I-45

Subject: **Tab 5: Financial Results & Forecast**

Reference: **Tab 5 Pages 27 to 30 of 30 - Payments to Governments**

a) Please provide a schedule demonstrating Centra's payments to governments (federal, provincial and municipal) by type for 2009/10 to 2013/14 on a similar basis to that presented in response to PUB/CENTRA 47 at the 2009/10 & 2010/11 GRA.

ANSWER:

Centra was no longer subject to provincial income taxes and federal income taxes subsequent to the acquisition of the company by Manitoba Hydro. Centra's deferred income taxes represent the one-time tax liability that was triggered by the acquisition of the company by Manitoba Hydro. In accordance with Order 118/03, Centra deferred the resulting liability and is amortizing the amount over a 30-year period.

As of April 1, 2001 all Centra employees were transferred to the payroll of Manitoba Hydro. Therefore, Centra no longer makes payments directly to the provincial and federal governments for payroll related taxes.

Of the payments included in the table below, only corporation capital taxes and property and business taxes are calculated and paid directly by Centra. The debt guarantee fee is initially paid by Manitoba Hydro and allocated to Centra based on the company's portion of total outstanding corporate group debt. Similarly, payroll taxes are paid by Manitoba Hydro and allocated to Centra in line with total labour charges allocated.

Summary of Payments to Government **($000's)**

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Test Year	2013/14 Test Year
Provincial Payments:					
Income Tax	n/a	n/a	n/a	n/a	n/a
Corporation Capital Taxes	2,377	2,398	2,323	2,304	2,516
Debt Guarantee Fee	3,382	3,142	3,103	3,048	2,975
Payroll Taxes	788	802	800	793	807
Total Provincial Payments	6,547	6,342	6,226	6,145	6,298
Federal Payments:					
Income Tax	n/a	n/a	n/a	n/a	n/a
Employment Insurance	n/a	n/a	n/a	n/a	n/a
Canadian Pension Plan	n/a	n/a	n/a	n/a	n/a
Total Federal Payments	-	-	-	-	-
Municipal Payments:					
Property & Business Taxes	14,836	10,844	11,561	10,861	11,187
Total Corporate Payments	21,383	17,186	17,787	17,006	17,485

54.

CAPITAL EXPENDITURE FORECAST (CEF12)

(in millions of dollars)

	Total Project Cost	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Customer Care & Marketing											
Advanced Metering Infrastructure	30.9	-	-	4.0	5.4	5.5	5.6	4.4	3.9	-	-
Customer Care & Marketing Domestic	NA	3.0	3.1	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.4
Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-
		3.0	3.1	7.9	9.3	9.4	9.7	8.5	8.2	4.3	4.4
Finance & Administration											
Corporate Buildings	NA	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
1840 Chevrier Apparatus Maintenance Shop Ancilliary Processing Facility	4.0	-	1.3	1.8	0.9	-	-	-	-	-	-
EAM Phase 2	18.6	5.0	5.1	2.6	-	-	-	-	-	-	-
Workforce Management (Phase 1 to 4)	17.7	1.4	-	-	-	-	-	-	-	-	-
Fleet	NA	13.0	14.3	14.6	14.9	15.2	15.5	15.8	16.2	16.5	16.8
Finance & Administration Domestic	NA	22.0	25.9	26.5	27.0	27.5	28.1	28.7	29.2	29.8	30.4
Target Adjustment	NA	(1.9)	(6.5)	-	-	-	-	-	-	-	-
		47.5	48.3	53.5	50.8	50.8	51.6	52.5	53.4	54.3	55.2
ELECTRIC CAPITAL SUBTOTAL		**1,342.9**	**1,858.8**	**2,009.2**	**2,075.0**	**2,217.6**	**2,185.3**	**1,878.8**	**1,683.7**	**1,819.3**	**2,319.9**
GAS											
Customer Service & Distribution											
Ile Des Chenes NG Transmission Network Upgrade	1.2	1.1	-	-	-	-	-	-	-	-	-
Gas SCADA Replacement	4.6	2.6	-	-	-	-	-	-	-	-	-
Customer Service & Distribution Domestic	NA	22.1	26.2	26.7	27.3	27.8	28.4	28.9	29.5	30.1	30.7
Target Adjustment	NA	(3.8)	(3.7)	-	-	-	-	-	-	-	-
		22.1	22.5	26.7	27.3	27.8	28.4	28.9	29.5	30.1	30.7
Customer Care & Marketing											
Advanced Metering Infrastructure	15.0	-	-	1.0	5.4	8.3	-	-	-	-	-
Demand Side Management	NA	9.3	8.8	-	-	-	-	-	-	-	-
Customer Care & Marketing Domestic	NA	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.7	5.8
Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-
		14.2	13.7	6.0	10.6	13.5	5.3	5.4	5.5	5.7	5.8
GAS CAPITAL SUBTOTAL		**36.3**	**36.2**	**32.8**	**37.8**	**41.3**	**33.7**	**34.4**	**35.1**	**35.8**	**36.5**
CONSOLIDATED CAPITAL		**1,379.1**	**1,895.0**	**2,041.9**	**2,112.8**	**2,258.9**	**2,219.0**	**1,913.2**	**1,718.8**	**1,855.1**	**2,356.4**
G911 Fall Update Base Capitalized Interest Revision	NA	-	(0.3)	(0.4)	(0.6)	(0.4)	(0.4)	(0.5)	(0.5)	(0.6)	(0.6)
CEF12 TOTAL		**1,379.1**	**1,894.7**	**2,041.5**	**2,112.2**	**2,258.5**	**2,218.6**	**1,912.7**	**1,718.3**	**1,854.4**	**2,355.8**

CENTRA GAS MANITOBA INC. **Schedule 9.2.4**

Major Capital Project List

2012/13 Forecast **($000'S)**

		Classification
	[1]	[2]
Projects greater than $100,000		
System Load Growth	10,686	Justifiable 1
Plough Projects	4,000	Justifiable 1
Distribution System Upgrades:		
Meters	3,164	Necessary 1
System Capacity Upgrades	350	Justifiable 1
Pipeline Relocations	400	Essential
System Integrity Upgrades	350	Necessary 1
Regulator Station Upgrades	1,640	Essential
Integrity Management Projects	681	Necessary 1
Cathodic Protection Upgrades	319	Necessary 1
Large General Services (LGS) Upgrades	40	Necessary 1
System Upgrades - Services	1,406	Essential
Ile Des Chenes NG Trans Network Upgrade	718	Necessary 1
Southglen Trailer Park Distribution Upgrade	280	Necessary 1
Gas SCADA Replacement	3,779	Necessary 1
Other Distribution System Upgrades	61	Justifiable 1
Total Forecast Additions	27,874	

CENTRA GAS MANITOBA INC. **Schedule 9.2.5**

Major Capital Project List

2013/14 Test Year **($000'S)**

		Classification
	[1]	[2]
Projects greater than $100,000		
System Load Growth	11,490	Justifiable 1
Plough Projects	4,000	Justifiable 1
Distribution System Upgrades:		
Meters	3,695	Necessary 1
System Capacity Upgrades	400	Justifiable 1
Pipeline Relocations	450	Essential
System Integrity Upgrades	400	Necessary 1
Regulator Station Upgrades	1,613	Essential
Integrity Management Projects	679	Necessary 1
Cathodic Protection Upgrades	325	Necessary 1
System Upgrades - Services	1,639	Essential
Other Distribution System Upgrades	4,206	Justifiable 1
Total Forecast Additions	28,897	

55.

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

Updated Schedule 9.0.0
Cost of Gas Update May 10, 2013

($000'S)

	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Test
	[1]	[2]	[3]	[4]	[5]	[6]
Cost of Gas	430,759	315,840	260,835	197,099	175,576	183,202
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
Corporate Allocation	12,000	12,000	12,000	12,000	12,000	12,000
Return on Rate Base	33,692	31,196	32,201	33,559	33,785	30,711
Revenue Requirement from Gas Rates	582,667	465,111	410,367	348,559	332,910	341,688
Gas Plant in Service	598,287	606,434	621,136	637,887	658,683	681,747
Accumulated Depreciation	(205,961)	(214,029)	(221,126)	(227,334)	(232,935)	(241,999)
Net Plant	392,325	392,406	400,010	410,552	425,747	439,749
Contributions in Aid of Construction	(46,150)	(46,712)	(48,566)	(49,936)	(51,931)	(53,062)
Working Capital Allowance	115,867	91,986	100,022	104,247	105,031	102,605
Rate Base	462,042	437,680	451,466	464,864	478,847	489,292

Centra Gas Manitoba Inc.
ROE formula results for 2013/14
Based On November 2012 Consensus Forecast

Approved ROE formula per page 109 of Board Order 49/95 :

Allowed ROE for 1995	**12.12%**
Plus/ (minus) 80% of the change in the forecast Long Canada bond yield	**-5.23%**
Revised ROE for 2013/14	**6.89%**

Supporting Calculations :

1) November 2012 average forecast 10 year Long Canada yields:

3 Month	12 Month	Avearge
1.80%	2.20%	2.00%

2) 10 to 30 year Long Canada spread for the last 6 trading days in November:

Date	30 Year Benchmark Jun 01/41	10 Year Benchmark Jun 01/22	10 to 30 Year Spread
23-Nov-12	2.36%	1.78%	0.57%
26-Nov-12	2.34%	1.76%	0.58%
27-Nov-12	2.31%	1.73%	0.58%
28-Nov-12	2.30%	1.72%	0.58%
29-Nov-12	2.30%	1.70%	0.59%
30-Nov-12	2.29%	1.70%	0.60%
Average Spread			0.58%

3) 2013 Long Canada forecast:

Average 10 Year Forecast	10 to 30 Year Spread	30 Year Forecast
2.00%	0.58%	2.58%

4) 80% of change in Long Canada Forecast

2013 30 year Forecast	1995 30 year Forecast	Change	80% of Change
2.58%	9.12%	**-6.54%**	**-5.23%**

PUB/CENTRA I-84

Subject: Tab 9: Rate Base

Reference: Tab 9 Page 58 of 63 - ROE

a) Please file the referenced reviews of Return on Equity.

ANSWER:

The referenced reviews were undertaken by the British Columbia Utilities Commission (“BCUC”), the Alberta Utilities Commission (“AUC”), the Ontario Energy Board (“OEB”) and the National Energy Board (“NEB”). The table below provides the most recently approved ROE for each jurisdiction. What follows is a description of the referenced reviews of ROE.

OEB	8.98% ROE for May 1, 2013 rate changes
BCUC	9.5% Benchmark ROE effective January 1, 2013 interim
AUC	8.75% Generic ROE for 2012
NEB	7.58% ROE for 2012 based on formula discontinued in 2009*

OEB

On March 16, 2009, the OEB initiated a consultation process to help it to determine whether current economic and financial market conditions warranted an adjustment to any of its cost of capital parameter values (i.e., the ROE, long-term debt rate, and/or short-term debt rate). The consultation was initiated, in part, by (i) the fact that the spread between the cost of equity and the cost of long-term debt values determined by the Board for 2009 was only 39 basis points versus a spread of 247 basis points in 2008; and (ii) concern that the Board did not have a sufficiently robust approach within which to exercise its discretion to adjust any or all of the values produced by the application of the methodology.

CENTRA GAS MANITOBA INC. | **Revised Schedule 9.7.5**
Overall Rate of Return | **April 12, 2013**
2013/14 Test Year | **($000'S)**

	Capital Structure	Weight	Cost Rate	Weighted Cost of Capital
	[1]	[2]	[3]	[4]
Long Term Debt	295,000	61.3%	5.25%	3.22%
Short Term Debt	27,103	5.6%	2.30%	0.13%
Equity	159,524	33.1%	6.89%	2.28%
	481,627	100.0%		5.63%

CENTRA GAS MANITOBA INC.
Return on Rate Base
2013/14 Test Year

Updated Schedule 9.9.5
Cost of Gas Update May 10, 2013
($000'S)

	Rate Base [1]	Weight [2]	Cost Rate [3]	Return [4]
Long Term Debt	489,292	61.3%	5.25%	15,741
Short Term Debt	489,292	5.6%	2.30%	633
Equity	489,292	33.1%	6.89%	11,166
		100.0%		27,540
Interest on Common Assets and Inventory				3,171
Total Return on Rate Base				30,711

PUB/CENTRA I-87

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Schedules 9.9.4 and 9.9.5**

For 2013/14 please demonstrate that the requested revenue requirement (corporate allocation, finance expense and net income) on a cost of service basis does not exceed the overall approved return on rate base by preparing the following:

a) In a similar fashion to PUB/Centra 78 from the 2009/10 & 2010/11 GRA, for the test year, please file a schedule which shows the total expenditures for the following components of revenue requirement: finance expense, corporate allocation and net income. Compare that total with the return on rate base of $30.9 million for 2013/14 and provide the differences.

ANSWER:

The following table provides the total expenditures for the finance expense, corporate allocation and net income components of revenue requirement:

(000's)	2013/14
Finance expense	17,296
Corporate allocation	12,000
Net income	4,821
	34,117

In the schedule provided above, the Corporate Allocation and Net Income components of revenue requirement have been developed in accordance with post-acquisition rate decisions. These amounts consider cost savings that have accrued to the customers of Centra as a result of its acquisition by Manitoba Hydro as well as the retained earnings required by Centra to ensure its financial stability.

The Return on Rate Base provided in Schedule 9.9.5 is calculated as support to the Cost of Service revenue requirement and do not, in themselves, consider the costs and benefits of acquisition. The return amount is calculated in accordance with pre-acquisition standards.

Because of these fundamental differences in the way each of these methodologies determines net income, no direct comparison can be made.

The most appropriate comparison of these different return methodologies is that of the total revenue requirement calculated under each methodology. These are provided in Centra's response to PUB/Centra I-12 for Cost of Service methodology and in Schedule 9.0.0 for Rate Base Rate of Return methodology. In these schedules, the Rate Base Rate of Return methodology shows a substantially higher revenue requirement.

This result is due to the Rate Base Rate of Return schedule incorporating income as would have been calculated pre acquisition plus the Corporate Allocation which approximates the minimum net level of benefits to Centra as a result of its acquisition by Manitoba Hydro. By comparison, the Cost of Service Revenue Requirement incorporates a reduced level of income, thereby passing on an appropriate level of the acquisition benefit to the customers of Centra.

The following table provides a comparison of Revenue Requirement under each methodology:

(000's)	**2013/14**
Rate Base Methodology	326,780
Cost of Service Methodology	318,171
Net Difference	8,609

56.

PUB/CENTRA I-130

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 Pages 4 and 5 of 7 - Modifications to Customer Equipment Problems Program**

a) **For each of the past five years, please provide a breakdown of the total number of service calls, the total cost of service calls, and the average cost per service call broken down into the following categories:**

a. **Commercial**

i. **Space heating**

ii. **Water heating**

iii. **Other**

b. **Residential**

i. **Space heating**

ii. **Water heating**

ii. **Other**

ANSWER:

The following tables illustrate a breakdown of the total number of service calls, total cost of service calls and the average cost of service calls broken down by Space Heating, Water Heating and Other categories for each of commercial and residential work orders:

a) Commercial

		Number of Calls			Average time per call in minutes			Average Cost per call		
	Fiscal Year	Other	Space Heating	Water Heating	Other	Space Heating	Water Heating	Other	Space Heating	Water Heating
Commercial	2007-08	-	3	-	-	79.7	-	-	$ 100.91	-
	2008-09	-	4	-	-	38.0	-	-	$ 48.13	-
	2009-10	-	2	-	-	85.5	-	-	$ 108.30	-
	2010-11	-	-	-	-	-	-	-	-	-
	2011-12	-	-	-	-	-	-	-	-	-
	2012-13	-	-	-	-	-	-	-	-	-

Note: No calls were recorded in years 2010-11 to 2012-13.

Centra does not keep specific records of costs incurred for each service call related to commercial Space Heating, Water Heating or Other. Total costs can be inferred by the product of number of calls completed and the average cost per call. Using this calculation the total cost of commercial service calls related to space heating for each of 2007/08, 2008/09 and 2009/10 is estimated to be $303, $193 and $217 respectively.

b) Residential

		Number of Calls			Average time per call in minutes			Average Cost per call		
	Fiscal Year	Other	Space Heating	Water Heating	Other	Space Heating	Water Heating	Other	Space Heating	Water Heating
Residential	2007-08	2072	16561	2310	59.2	50.0	49.3	$ 74.94	$ 63.38	$ 62.44
	2008-09	1573	15890	2199	61.1	54.0	51.8	$ 79.44	$ 70.26	$ 67.34
	2009-10	1379	12869	2290	61.5	54.8	53.6	$ 91.23	$ 81.29	$ 79.50
	2010-11	1522	13616	2258	61.7	57.0	56.0	$ 77.11	$ 71.25	$ 70.06
	2011-12	1248	13161	2479	59.1	56.8	54.5	$ 87.73	$ 84.28	$ 80.80
	2012-13	1132	12655	2201	62.6	55.8	55.3	$ 78.21	$ 69.78	$ 69.08

Centra does not keep specific records of costs incurred for each service call related to residential Space Heating, Water Heating or Other. Total costs can be inferred by the product of number of calls completed and the average cost per call.

		Total Costs of Service Calls		
Residential	Fiscal Year	Other	Space Heating	Water Heating
	2007-08	$155,000	$1,050,000	$144,000
	2008-09	$125,000	$1,116,000	$148,000
	2009-10	$126,000	$1,046,000	$182,000
	2010-11	$117,000	$970,000	$158,000
	2011-12	$109,000	$1,109,000	$200,000
	2012-13	$88,000	$883,000	$152,000

57.

Centra Gas Manitoba Inc.
Appendix B - Schedule of Sales and Transportation Services and Rates
Company Labour Rates to come into effect upon Order of the Board (Proposed)

February 22, 2013

Service Type	Location	Regular Hourly Rate	Overtime Hourly Rate
Service Line Alterations	All Areas	$121.00	$169.00
Damage Repairs	All Areas	$121.00	$169.00
Damage Investigation	All Areas	$131.00	$184.00
Appliance Relights	All Areas	$121.00	$169.00
Metering Services	All Areas	$136.00	$191.00
Gas Pipeline Operational Services	EastMan	$131.00	$184.00
"As Built" Plans	All Areas	$134.00	$187.00

PUB/CENTRA I-131

Subject: **Tab 14 Terms and Conditions**

Reference: **Tab 14 Appendix 14.3 - Proposed Labour Rates**

a) Please file Centra's labour rates for each of the five categories set out in Appendix 14.3 as approved in 2007/08 and in 2009/10.

ANSWER:

Please see the attachment to this response.

Service Type	Location	Regular Hourly Rate	Overtime Hourly Rate
Service Line Alterations	All Areas	$98.00	$136.00
Damage Repairs	Winnipeg East	$95.00	$134.00
	Parkland	$120.00	$161.00
	WestMan	$120.00	$161.00
	EastMan	$120.00	$161.00
	Interlake	$110.00	$146.00
Metering Services	All Areas	$86.00	$125.00
Gas Pipeline Operational Services	EastMan	$128.00	n/a

Approved by Manitoba Public Utilities Board Order: 99/07
Supercedes Rates in Manitoba Public Utilities Board Order 174/05
Effective from: August 1, 2007
Date Implemented: August 1, 2007

Centra Gas Manitoba Inc. **September 16, 2009**
Appendix B - Schedule of Sales and Transportation Services and Rates
Company Labour Rates Effective September 16, 2009 **Page 1 of 1**

Service Type	Location	Regular Hourly Rate	Overtime Hourly Rate
Service Line Alterations	All Areas	$103.00	$147.00
Damage Repairs	Winnipeg East	$110.00	$159.00
	Parkland	$128.00	$170.00
	WestMan	$128.00	$170.00
	EastMan	$128.00	$170.00
	Interlake	$128.00	$170.00
Metering Services	All Areas	$99.00	$148.00
Gas Pipeline Operational Services	EastMan	$128.00	$170.00

Approved by PUB Order No.: **128/09**
Date of Board Order: **Sept 16/2009**

PUB/CENTRA I-131

Subject: Tab 14 Terms and Conditions

Reference: Tab 14 Appendix 14.3 - Proposed Labour Rates

b) For each of the proposed labour rates set out in Appendix 14.3, please provide the actual hourly cost, to Centra, of regular staffing and overtime pay, broken down into components to the extent possible, and advise which components have changed as a result of changes to Centra's overhead capitalization practice.

ANSWER:

Please see the table below reflecting the breakdown of the proposed labour rates for the service types set out in Appendix 14.3.

	Service Line Alterations	Damage Repairs	Damage Investigation	Appliance Relights	Metering Services	Gas Pipeline Operational Services	"As Built" Plans
Activity Rate	79	79	86	79	89	86	87
Overhead	20	20	21	20	22	21	22
Third Party Provision	22	22	24	22	25	24	24
Regular Hourly Rate	**121**	**121**	**131**	**121**	**136**	**131**	**134**
Overtime Hourly Rate (Regular plus 40%)	**169**	**169**	**184**	**169**	**191**	**184**	**187**

Centra has used internal activity & overhead rates to calculate Company Labour Rates for third party billings. Changes in costing methodology have resulted in the reallocation of departmental support costs previously included in activity rates to the common overhead rate. The overhead line item reflects the reallocation of department support costs previously included in activity rates.

In addition, changes in overhead capitalization practices have resulted in some cost components being eliminated from common overhead. As a result, the application of overhead would not recover all of the costs associated with the provision of the chargeable customer service. To appropriately recover the costs incurred in providing the service, the utility has included a provision in the calculation of the company Labour Rates to reflect the same costs that were included in previously approved rates. The third party line item reflects cost components eliminated from common overhead including interest on equipment and facilities, building depreciation and operating costs, IT infrastructure and related support, as well as various corporate department costs.

58.

Financial Feasibility Test

1	**MER 2012-00139 Pine Drive - La Broquerie**										
2		YEAR 0	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
3		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
4	**OPERATING ASSUMPTIONS**											
5	Number of Customers		3	6	9	12	14	14	14	14	14	14
6	Annual Volume (Mcf)		300	600	900	1200	1400	1400	1400	1400	1400	1400
7	Annual Volume (10^3m^3)		8	17	25	34	40	40	40	40	40	40
8	Projected Revenues		$2,575	$5,149	$7,724	$10,298	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014
9	**RATE BASE**											
10	Gross Fixed Assets	$43,315	$46,962	$50,681	$54,475	$58,345	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977
11	Accumulated Depreciation		$1,353	$2,812	$4,381	$6,061	$7,818	$9,574	$11,330	$13,086	$14,842	$16,598
12	Net Plant Closing	$43,315	$45,609	$47,869	$50,094	$52,284	$53,159	$51,403	$49,647	$47,891	$46,135	$44,379
13	Net Plant at Mid-Year		$44,462	$46,739	$48,982	$51,189	$52,721	$52,281	$50,525	$48,769	$47,013	$45,257
14	Contributions	$9,240	$8,974	$8,708	$8,442	$8,176	$7,910	$7,644	$7,378	$7,111	$6,845	$6,579
15	Contributions at Mid-Year		$9,107	$8,841	$8,575	$8,309	$8,043	$7,777	$7,511	$7,244	$6,978	$6,712
16	Working Capital Allowance		$117	$186	$254	$322	$368	$368	$367	$367	$366	$366
17	Rate Base at Mid-Year		$35,472	$38,084	$40,661	$43,203	$45,047	$44,872	$43,381	$41,891	$40,401	$38,910
18	**REVENUE DEFICIENCY CALCULATION**											
19												
20	Cost of Gas		$1,273	$2,545	$3,818	$5,091	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939
21	Operating & Maintenance Expenses		$120	$240	$360	$480	$560	$560	$560	$560	$560	$560
22	Depreciation Expense		$1,353	$1,460	$1,569	$1,680	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756
23	Amortization of Contributions		($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)
24	Municipal Tax & Corp.Cap. Tax		$1,084	$1,140	$1,196	$1,252	$1,286	$1,277	$1,268	$1,260	$1,251	$1,242
25	Income Taxes		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return		$2,157	$2,316	$2,472	$2,627	$2,739	$2,728	$2,638	$2,547	$2,457	$2,366
27	Total Revenue Requirement		$5,720	$7,435	$9,149	$10,864	$12,014	$11,995	$11,896	$11,796	$11,697	$11,597
28	Projected Revenues		$2,575	$5,149	$7,724	$10,298	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014
29	Revenue Sufficiency (Deficiency)		($3,146)	($2,286)	($1,426)	($566)	$0	$19	$119	$218	$318	$417
30	Revenue to Cost Ratio		45.0%	69.3%	84.4%	94.8%	100.0%	100.2%	101.0%	101.8%	102.7%	103.6%
31	Net Present Value	$2,029										
32	**CONTRIBUTION REQUIREMENT**											
33	Total Contribution Required	$9,240										

Financial Feasibility Test

1	**MER 2012-00139 Pine Drive - La Broquerie**										
2		YEAR 11	YEAR 12	YEAR 13	YEAR 14	YEAR 15	YEAR 16	YEAR 17	YEAR 18	YEAR 19	YEAR 20
3		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
4	**OPERATING ASSUMPTIONS**										
5	Number of Customers	14	14	14	14	14	14	14	14	14	14
6	Annual Volume (Mcf)	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400
7	Annual Volume (10^3m^3)	40	40	40	40	40	40	40	40	40	40
8	Projected Revenues	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014
9	**RATE BASE**										
10	Gross Fixed Assets	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977
11	Accumulated Depreciation	$18,354	$20,110	$21,867	$23,623	$25,379	$27,135	$28,891	$30,647	$32,403	$34,159
12	Net Plant Closing	$42,622	$40,866	$39,110	$37,354	$35,598	$33,842	$32,086	$30,329	$28,573	$26,817
13	Net Plant at Mid-Year	$43,500	$41,744	$39,988	$38,232	$36,476	$34,720	$32,964	$31,208	$29,451	$27,695
14	Contributions	$6,313	$6,047	$5,781	$5,515	$5,249	$4,982	$4,716	$4,450	$4,184	$3,918
15	Contributions at Mid-Year	$6,446	$6,180	$5,914	$5,648	$5,382	$5,116	$4,849	$4,583	$4,317	$4,051
16	Working Capital Allowance	$365	$365	$365	$364	$364	$363	$363	$363	$362	$362
17	Rate Base at Mid-Year	$37,420	$35,929	$34,439	$32,949	$31,458	$29,968	$28,477	$26,987	$25,496	$24,006
18	**REVENUE DEFICIENCY CALCULATION**										
19											
20	Cost of Gas	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939
21	Operating & Maintenance Expenses	$560	$560	$560	$560	$560	$560	$560	$560	$560	$560
22	Depreciation Expense	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756
23	Amortization of Contributions	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)
24	Municipal Tax & Corp.Cap. Tax	$1,233	$1,225	$1,216	$1,207	$1,198	$1,189	$1,181	$1,172	$1,163	$1,154
25	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return	$2,275	$2,185	$2,094	$2,003	$1,913	$1,822	$1,732	$1,641	$1,550	$1,460
27	Total Revenue Requirement	$11,498	$11,399	$11,299	$11,200	$11,100	$11,001	$10,902	$10,802	$10,703	$10,603
28	Projected Revenues	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014
29	Revenue Sufficiency (Deficiency)	$516	$616	$715	$815	$914	$1,013	$1,113	$1,212	$1,312	$1,411
30	Revenue to Cost Ratio	104.5%	105.4%	106.3%	107.3%	108.2%	109.2%	110.2%	111.2%	112.3%	113.3%

Financial Feasibility Test

1	**MER 2012-00139 Pine Drive - La Broquerie**										
2		YEAR 21	YEAR 22	YEAR 23	YEAR 24	YEAR 25	YEAR 26	YEAR 27	YEAR 28	YEAR 29	YEAR 30
3		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
4	**OPERATING ASSUMPTIONS**										
5	Number of Customers	14	14	14	14	14	14	14	14	14	14
6	Annual Volume (Mcf)	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400
7	Annual Volume (10^3m^3)	40	40	40	40	40	40	40	40	40	40
8	Projected Revenues	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014
9	**RATE BASE**										
10	Gross Fixed Assets	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977	$60,977
11	Accumulated Depreciation	$35,916	$37,672	$39,428	$41,184	$42,940	$44,696	$46,452	$48,208	$49,965	$51,721
12	Net Plant Closing	$25,061	$23,305	$21,549	$19,793	$18,037	$16,280	$14,524	$12,768	$11,012	$9,256
13	Net Plant at Mid-Year	$25,939	$24,183	$22,427	$20,671	$18,915	$17,159	$15,402	$13,646	$11,890	$10,134
14	Contributions	$3,652	$3,386	$3,120	$2,853	$2,587	$2,321	$2,055	$1,789	$1,523	$1,257
15	Contributions at Mid-Year	$3,785	$3,519	$3,253	$2,987	$2,720	$2,454	$2,188	$1,922	$1,656	$1,390
16	Working Capital Allowance	$361	$361	$360	$360	$360	$359	$359	$358	$358	$358
17	Rate Base at Mid-Year	$22,516	$21,025	$19,535	$18,044	$16,554	$15,063	$13,573	$12,083	$10,592	$9,102
18	**REVENUE DEFICIENCY CALCULATION**										
19											
20	Cost of Gas	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939	$5,939
21	Operating & Maintenance Expenses	$560	$560	$560	$560	$560	$560	$560	$560	$560	$560
22	Depreciation Expense	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756	$1,756
23	Amortization of Contributions	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)	($266)
24	Municipal Tax & Corp.Cap. Tax	$1,145	$1,137	$1,128	$1,119	$1,110	$1,102	$1,093	$1,084	$1,075	$1,066
25	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Overall Return	$1,369	$1,278	$1,188	$1,097	$1,007	$916	$825	$735	$644	$553
27	Total Revenue Requirement	$10,504	$10,405	$10,305	$10,206	$10,106	$10,007	$9,908	$9,808	$9,709	$9,609
28	Projected Revenues	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014	$12,014
29	Revenue Sufficiency (Deficiency)	$1,510	$1,610	$1,709	$1,809	$1,908	$2,008	$2,107	$2,206	$2,306	$2,405
30	Revenue to Cost Ratio	114.4%	115.5%	116.6%	117.7%	118.9%	120.1%	121.3%	122.5%	123.7%	125.0%

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Subject: **Tab 15 - Directives**

Reference: **Tab 15 Appendix 15.1**

f) Please provide all the inputs used in the feasibility test, as well as when each input was last updated or approved by the PUB. Please briefly explain the rationale for each input.

ANSWER:

Please see the table below.

INPUTS	UPDATE	RATIONALE
Operating Assumption Inputs		
Number of Customers	Input at time of feasibility Updated for actual at true-up	Projection of the number of customers that will attach over the life of the project. Used to forecast Basic Monthly Charge (BMC) revenues and volumes.
Annual Volume	Input at time of feasibility Updated for actual at True-up	Estimated annual consumption used to calculate projected revenues.
Base Sales Rates & BMC	Most recently approved PUB rates Updated for current rates at the time of true-up	Base Sales rates and BMC used to calculate projected revenues.
Rate Base Inputs		
Capital Costs	Input at time of feasibility Updated for actual at true-up	Includes all estimated capital costs associated with the proposed expansion. Used as the input to Gross Fixed Assets.
Inflation Rate	Assumed at 2% in initial feasibility study. Not applicable at time of true-up as actual construction costs are used.	Inflation rate only applied to escalate service capital added after year 1. Meant to recognize additional construction cost risks in future periods.
Working Capital Allowance	Assumes 15-day lag applied to gas costs, O&M and taxes Rate is maintained in true-up	The lead lags days are used to calculate the incremental working capital allowance required to serve the proposed extension.
Revenue Deficiency Calculation Inputs		
WACOG Rates	Most recently approved PUB rates Updated for current rates at the time of true-up	WACOG Rates are used to calculate the projected annual Cost of Gas.
Operating & Maintenance	Reviewed depending upon the scope and scale of project Original estimate included in true-up (not updated for actual)	Represents a reasonable estimate of the incremental costs to serve the proposed extension.

INPUTS	UPDATE	RATIONALE
Depreciation Rate	Orders 128/09 & 41/10 Updated for current rates at the time of true-up	Used to calculate the depreciation expense of the Fixed Assets. Weighted average calculation based on the most recently approved test year (2010/11).
Amortization Rate	Orders 128/09 & 41/10 Updated for current rates at the time of True-up	Used to calculate the amortization of customer contributions. Weighted average calculation based on the most recently approved test year (2010/11)
Property Tax Mill Rates	September, 2012 Updated for current rates at the time of true-up	Used to calculate the projected taxes owed on the gross plant.
Property Tax Assessment Rates	2012 Updated for current rates at the time of true-up	Used to calculate the projected taxes owed on the gross plant.
Corporate Capital Tax	August 1, 2003 Most recent tax rate was established in 2003.	Provincial requirement to pay corporate tax.
Overall Rate of Return	Orders 128/09 & 41/10 True-up reflects most recently approved second test year rate of return	Used to calculate Centra's Overall Return as part of the revenue deficiency calculation. Weighted average calculation based on the most recently approved test year (2010/11).
Discount Rate	Orders 128/09 & 41/10 Updated for current rates at the time of true-up	Used to calculate the Net Present Value of future revenue deficiency cash flows. Discounting at the weighted average cost of capital based on the most recently approved test year (2010/11).

59.

Order	#	Order 128/09 - Directives	Status	Comment
128/09	5	The Board directs Centra to file a semi-annual status update report on the FRP to begin with a report by December 31, 2009.	Ongoing	Centra is in compliance with this directive. Please see the response to Directive 6 of Order 55/10 for further information.
128/09	10	Centra to perform a true-up and adjustment on a quarterly basis to ensure there has been no over- or under-recovery of short term finance costs charged to Centra from MH.	Complete	Centra completed the true-up effective April 1, 2009, and an adjustment is performed on a quarterly basis.
128/09	11	Centra to file on or before March 1, 2010 a terms of reference for a study to review the Integrated Cost Allocation Methodology. The study is to be completed in sufficient time to be incorporated within the corporation's next MH or Centra GRA.	Outstanding	As noted in a letter to the PUB dated September 30, 2010, the implementation of this Directive is impacted by the implementation of International Financial Reporting Standards ("IFRS"). Given the industry wide delays in confirming the nature of the changes required under IFRS, the response to this Directive will be delayed until post-IFRS implementation.
128/09	13	Centra to file a business plan with respect to the AMI project with the Board for its approval by January 15, 2010, and prior to proceeding beyond the pilot project expenditures. The business plan should include an assessment of the economic and noneconomic benefits of AMI, including safety-related matters, for both the meter reader and for Centra's customers.	Outstanding	A Status Report on AMI was filed with the PUB on February 2, 2010. A business plan will be filed with the PUB prior to proceeding with AMI implementation.
128/09	21	Centra is to prepare and file with the Board a discussion paper by December 1, 2010 advising whether Centra or MH should direct or mandate a specific energy source, such as natural gas, be made available to consumers, and whether Centra and MH should publish recommendations for the most economic and environmental fuel source.	Complete	On September 11, 2012, Manitoba Hydro provided the report "Economic, Load, and Environmental Impacts of Fuel Switching in Manitoba" as its response to Directive 17 in electric operations regulatory Order 150/08. In that report, the high level strategy discussion that appears on page 39 is intended to be responsive to Directive 21 of gas operations Order 128/09. A copy of the report is provided as Appendix 15.4 to this Application.
128/09	26	If and when Centra becomes aware of any material change in its financial circumstances, including but not limited to significant changes to accounting, gas supply, or operations, Centra must inform the Board of the change and the resulting impact or anticipated impact on Centra's financial position.	Ongoing	Centra will comply with this Directive should a material change in financial circumstance occur.

Order	#	Order 55/10 - Directives	Status	Comment
55/10	1	The Board directs Centra to inform ConocoPhillips of the Board's intention to release the Primary Gas supply contract to the Consumers' Association of Canada and Manitoba Society of Seniors (CAC/MSOS), interveners in the recent proceeding, including their counsel and external consultant. The disclosure would take place in the Board's office, and the Board will require the intervener and its counsel and advisor to sign nondisclosure agreements.	Superseded	This directive has been superseded by Directive 9 from Order 65/11. Please see below.
55/10	3	Centra is to file with the Board a discussion paper reviewing and addressing the issue of the possible future replacement of Centra's current American Storage and Transportation assets, prior to Centra holding a technical conference on the topic.	Complete	Centra filed its submission on the Process for Review of Gas Supply, Storage and Transportation Arrangements on June 27, 2011. In its submission, Centra provided an ICF report titled 'Review of Natural Gas Supply Portfolio Options for Centra Gas, dated June 2011.
55/10	4	Centra is to consult with its higher volume customers and alert them to opportunities to lock in gas supply prices, either through Centra or marketer fixed term contracts, or by self-directed futures contract acquisition, and provide the Board with the results of these consultations.	Complete	The minutes of the Customer Advisory Group Meeting were provided to the PUB on September 30, 2010. As Appendix 15.3 to this Application, Centra has included the findings of a survey of its highest volume natural gas customers undertaken by Manitoba Hydro. Please refer to Tab 15 of this Application for more information.
55/10	6	Centra is to file quarterly updates on the participation rate and the order book for the Lower Income Energy Efficiency Program (LIEEP) that specifically details the number of customers participating in each facet of the LIEEP – low-cost measures, insulation, and furnace replacements, with commentary. This information is to supplement the more detailed semi-annual Furnace Replacement Program Status report (directed to be filed with the Board by Order 128/09). If there are changes in the number of contractors used by Centra or with Centra's marketing efforts of LIEEP, these changes should be included in this report to the Board.	Ongoing	On December 21, 2012, Centra filed the LIEEP/FRP Quarterly Reports containing the results for the second, third and fourth quarters of fiscal 2011/12, and the first and second quarters of fiscal 2012/13. These reports are provided as Appendix 7.3 to this Application.
55/10	11	Centra is to file its next General Rate Application utilizing a revenue to cost ratio of unity in its Cost Allocation Model.	Complete	Consistent with past practice, Centra has prepared its Cost Allocation Study with a revenue to cost ratio of one. Please refer to Tab 11 and 12 of this Application.

Order	#	Order 93/10 - Directives	Status	Comment
93/10	2	Centra report to the Board within 90 days of the date of this Order, with new proposals for alternative business models / options to allow for the continuous availability of FRPGS options for gas customers.	Complete	Centra has proposed changes to the rate setting methodology for FRPGS in Tab 13 of this Application.
93/10	3	Centra report to the Board as to options for hedging its FRPGS offerings, in the event that current counterparties discontinue to provide hedges and new counterparties cannot be involved (Board staff and Advisors remain available for discussion with Centra representatives to explore options).	Complete	This matter is addressed in response to Directive 2 from Order 93/10.
93/10	4	Centra immediately inform the Board if it is unable to hedge its FRPGS offerings.	Complete	Please refer to Tab 13 of this Application.
Order	**#**	**Order 56/11 - Directives**	**Status**	**Comment**
56/11	2	For now, Centra is to recover the additional Furnace Replacement Program costs associated with the loss of funds from the Federal ecoEnergy Retrofit program from overall Furnace Replacement Program funds.	Complete	Centra has proceeded to recover the additional program costs from the Furnace Replacement Program funds.

Order	#	Order 65/11 - Directives	Status	Comment
65/11	9	CAC/MSOS' counsel and advisor are to view the ConocoPhillips gas supply contract and pricing details including the proposal submissions of the other Proponents. This review will take place in the Board's office subject to the execution of non-disclosure agreements that limit liquidated damages to $10,000 for both intentional and unintentional disclosure.	Complete	CAC/MSOS has declined to enter into the current terms of the non-disclosure agreement.
65/11	10	Centra amend the COG methodology such that Centra is to provide a gas cost forecast update in future COG proceedings, in a manner similar to that of GRA proceedings.	Ongoing	Centra will comply with this Directive at a future Cost of Gas proceeding.
65/11	11	Centra amend the process for replacing its U.S. storage and transportation assets to include a detailed discussion paper with sufficient economic and operational analysis, an information request process, submissions from interveners and stakeholders, and an oral public hearing before the Board.	Complete	A stakeholder consultation process was undertaken, and an oral public hearing was held in respect of Centra's Application for approval of the fixed costs associated with its U.S. storage and transportation portfolio arrangements.
65/11	12	Centra file, by May 20, 2011, a revised timeline for the amended process of replacing its U.S. storage and transportation assets such that Board approval of the gas cost consequences be a condition precedent to the formation of any contracts related to this issue.	Complete	Please see the response to Directive 11 from Order 65/11.
65/11	13	Centra be permitted to unwind or otherwise close off any hedge positions related to its FRPGS that are not subscribed by customers. Alternatively, Centra may use these hedges to provide modified fixed rate service offerings to customers, subject to Board approval of the pricing and other terms.	Ongoing	Centra will comply with this Directive should a change in hedge positions related to FRPGS occur.
65/11	14	Centra to propose, by May 20, 2011, a process to review and obtain Board approval of Centra's rate and service structure – including the distinction between Primary and Supplemental Gas.	Outstanding	Please refer to Tab 11 of this Application for Centra's proposed approach for the review of its rate and service structure.
Order	**#**	**Order 159/11 - Directives**	**Status**	**Comment**
159/11	4	Centra shall apply for Board approval of its charge-out rates for purposes of Sections 3.(2) of the Negotiated Schedule and 3.(2) of the Proposed Generic Franchise Agreement as part of its next General Rate Application.	Complete	In Tab 14 of the Application, Centra has applied for a charge-out rate for the supply of "as-built" plans to a municipality with respect to Sections 3.(2) of the Negotiated Schedule and 3.(2) of the Generic Franchise Agreement.
159/11	5	Centra is to provide all franchise granting municipalities with a copy of this Order, including Appendix "A" and Appendix "B". Centra is to also advise those municipalities, that may be interested in replacing or revising their current franchise agreements to reflect the Board approved provisions arising from this Order, to file a copy of their amended franchise agreement (and related by-law) with the Board for approval.	Complete	In February 2012, Centra provided a copy of Order 159/11, including Appendix "A" and Appendix "B" to all franchise granting municipalities, and advised the municipalities of their right to enter into the new form of Generic Franchise Agreement.

Order	#	Order 70/12 - Directives	Status	Comment
70/12	5	Centra is to canvas potential customers in the franchise expansion area and provide the Board with a report on findings by December 31, 2012, including a revised feasibility test that accounts for potential revenues from additional customers accommodated with a NPS 4 pipe.	Outstanding	Centra has canvassed customers in the franchise expansion area in the Rural Municipality of Grey and is currently working on the report and revised feasibility test to be filed with the PUB. Centra expects to file this information on or around March 4, 2013.
Order	**#**	**Order 112/12 - Directives**	**Status**	**Comment**
112/12	2	If the annual fixed costs of Centra's Transportation & Storage Portfolio for any given year during the seven-year term change as a result of changes to the minimum or maximum FERC tariffs imposed on Centra's contractual counterparties, Centra is to seek the PUB's approval of those changed costs as part of its Cost of Gas Application for the respective year(s).	Outstanding	If there are changes to the fixed costs following implementation of the portfolio, Centra will seek approval through the next Cost of Gas Application for that respective year.
112/12	5	Centra is directed to, as part of its next Cost of Gas Application or GRA, to provide the monthly totals of its Capacity Management revenues from its current Transportation & Storage Portfolio broken down into type (capacity release or exchanges) and component of the Portfolio. These monthly revenues by component should also be shown as a percentage of the costs incurred by Centra to operate each Portfolio component for the given month. Centra is to also provide this information for its new Transportation & Storage Portfolio as part of each subsequent Cost of Gas Application.	Outstanding	As noted at Tab 10 of this Application, Centra is currently developing the necessary reporting to provide the monthly breakdown of Capacity Management revenue, and will file this information with the PUB as soon as it is available.