Exhibit PUB #

Volume 3 – Board Counsel's Book of Documents

Manitoba Hydro 2012/13 and 2013/14 GRA
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26	Depreciation Expense	Tab 5; Appendix 5.7 (excerpts)
27	Change in Service Life and Componentization	PUB/MH II – 34; Table 2: 2005 and 2010 Gannett Fleming Reports
28	Equal Life Group (ELG) and Financial Impacts of Changes to Depreciation Rates	MIPUG/MH I – 15; PUB/MH I – 85; Public Utility Depreciation Practices by NARUC
29	Removal of Asset Retirement Obligations (ARO) and Depreciation Methods for Crown-owned Canadian Utilities	Table C – 1; P. Bowman Nov 16/12
30	DSM: Program Spending	PUB/MH I – 102; 2011 Power Smart Plan (excerpts Appendix 7.1)
31	DSM: Annual Energy Savings	2011 Power Smart Plan Appendix A.3; PUB/MH I -107;CAC/GAC/MH II – 5(a)
32	DSM: Benchmarking	Dunsky Energy Consulting Report November 15, 2010 (excerpts); PUB/CAC/GAC 4.
33	DSM: Economic Screening	PUB/MH I – 107; PS Plan – Appendix F; PS Annual Review 2010-2011
34	DSM: Generation Deferral	PUB/CAC/GAC 18
35	DSM: Lower Income Energy Efficiency Program (LIEEP)	PUB/MH I – 109; 110

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

MANITOBA HYDRO
DEPRECIATION AND AMORTIZATION EXPENSE

Schedule 5.7.0
(000's)

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast*
Generation					
Hydraulic Generating Stations	74,310	76,128	75,064	97,254	97,852
Thermal Generating Stations	17,612	9,771	8,680	16,036	16,496
Demand Side Management	22,064	23,994	26,191	28,664	-
Diesel Generating Stations	3,552	3,691	1,359	1,407	1,368
Amortization of Contributions	(2,796)	(2,796)	(718)	(1,033)	(1,092)
	$ 114,743	$ 110,788	$ 110,576	$ 142,328	$ 114,624
Transmission					
Transmission	14,328	14,471	13,920	16,995	14,179
Amortization of Contributions	(1,638)	(1,629)	(1,357)	(1,358)	(1,360)
	$ 12,690	$ 12,842	$ 12,563	$ 15,636	$ 12,819
Stations					
Substations	74,123	76,747	79,157	87,181	80,893
Transformers	2,121	1,653	1,691	1,983	2,200
Amortization of Contributions	(1,464)	(1,470)	(1,247)	(1,235)	(1,235)
	$ 74,780	$ 76,930	$ 79,601	$ 87,929	$ 81,858
Distribution					
Subtransmission Lines	9,469	9,892	5,974	6,215	5,423
Distribution Lines	82,679	87,194	55,547	59,820	52,309
Meters & Transformers	1,590	1,615	4,205	5,019	5,603
Amortization of Contributions	(10,443)	(10,710)	(4,774)	(5,318)	(5,551)
	$ 83,295	$ 87,991	$ 60,952	$ 65,736	$ 57,784
Other					
Communications	20,947	22,518	20,118	25,153	29,634
Motor Vehicles	8,760	9,500	10,374	9,935	12,010
Structures & Improvements	6,590	7,422	7,618	8,509	9,495
General Equipment	18,006	17,172	23,493	23,011	21,226
Computer Development	14,454	15,253	18,895	16,376	18,937
Affordable Energy Fund	3,058	3,468	7,472	8,870	8,710
Miscellaneous	2,995	2,623	3,420	3,760	(3,418)
Corporate Allocation	(2,139)	(1,780)	(1,706)	(1,707)	(1,208)
Target Adjustment	-	-	-	(4,691)	(8,163)
	$ 72,671	$ 76,176	$ 89,684	$ 89,217	$ 87,223
Total Depreciation and Amortization Expense	$ 358,179	$ 364,727	$ 353,376	$ 400,846	$ 354,307
Year over year $ change		$ 6,548	$ (11,351)	$ 47,470	$ (46,539)
Year over year % change		1.8%	-3.1%	13.4%	-11.6%

* Includes the impacts of IFRS.

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 Manitoba Hydro 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 IFRS compliant depreciation practices and methodologies given that Manitoba Hydro will be required to implement IFRS compliant depreciation rates effective April 1, 2013.

As with previous depreciation studies, an external consultant, Gannett Fleming, Inc., was engaged to review Manitoba Hydro'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, Manitoba Hydro implemented the new asset component groupings and updated services lives effective April 1, 2011. In the second phase, Manitoba Hydro will implement IFRS compliant depreciation rates effective April 1, 2013 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.

Appendix 5.7
Electric 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, 2013 may be found in the tables on page 5-10, followed by a letter from Gannett Fleming, Inc. containing the depreciation rates to be used under GAAP, and by the full IFRS compliant Depreciation Study.

The following table provides a summary of the estimated changes to depreciation expense for electric operations for the 3 year period between 2012 and 2014:

	Depreciation Expense ($ 000's)		
	2012	2013	2014
Change in service life - PP&E (net of contributions)	(35,433)	(38,429)	(40,663)
Change in Methodology (ELG)			32,307
Removal of Asset Retirement Costs from Depreciation			(55,574)
Net Impact	(35,433)	(38,429)	(63,930)

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

Componentization & Change in Service Lives

In preparation for conversion to IFRS, Manitoba Hydro undertook a comprehensive review of existing depreciable component groupings, to determine whether IFRS requirements were met. IFRS is more rigorous than GAAP in terms of identifying separate components. As a result of this review, Manitoba Hydro determined that further componentization was required, primarily for generation and distribution assets. With the assistance of its depreciation consultant, Manitoba Hydro has established new component groupings consistent with the requirements of IFRS, and has completed a depreciation study based on these new component groupings.

Normally a depreciation study process is routine and involves updating the retirement experience of existing asset classes and reviewing operational factors to assess what new considerations are warranted. However, because of the new component groupings required under IFRS, an extensive effort involving accounting and operational personnel was required to research historical records and to assess operational factors of all new, existing and modified component groupings in order to establish account balances and to estimate service lives.

In addition, subject matter experts from the operational areas were able to provide information that has been developed through enhanced asset condition assessment processes that was not available in the 2005 depreciation study. This has resulted in less reliance on statistical developed asset lives and more reliance on the enhanced operational information. This is particularly the case with respect to distribution plant where the increased reliance on operational information has significantly extended the service lives and resulted in the majority of the reduction in depreciation expense. For example, the extension in estimated service lives for Poles and Fixtures from 33 to 55 years is due, in part, to the introduction of bar-coding and the ability to specifically track the service lives of individual poles. Further, enhancements in the use of pole preservatives and other technologies in recent years have resulted in extended service lives for these and other plant assets.

The estimated impact of these changes for Manitoba Hydro electric operations is a decrease to depreciation expense (net of contributions) of $35.4 million in 2011/12, $38.4 million in 2012/13 and $40.7 million in 2013/14.

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.

An IFRS requirement is 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 the need to change 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 Manitoba Hydro 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 in full compliance with IFRS and minimize retirement gains or losses that must be recognized in current income.

Appendix 5.7
Electric Depreciation Rates

Manitoba Hydro will be calculating depreciation rates based on ELG methodology effective April 1, 2013.

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 Manitoba Hydro electric operations is an increase to depreciation expense of $32.3 million in 2013/14.

<u>Removal of Asset Retirement Costs from Depreciation</u>

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, Manitoba Hydro will be eliminating this practice and removing asset retirement costs from its depreciation rates effective April 1, 2013.

The estimated impact of this change for Manitoba Hydro electric operations is a decrease to depreciation expense of $55.6 million in 2013/14.

Please see the following tables for the Electric depreciation rates.

Appendix 5.7
Electric Depreciation Rates

Depreciable Group	Effective April 1, 2007	Depreciable Group	Effective April 1, 2011	Effective April 1, 2013
HYDRAULIC GENERATION		**HYDRAULIC GENERATION**		
GREAT FALLS		**GREAT FALLS**		
Civil	1.33	Dams, Dykes & Weirs	1.28	1.10
		Powerhouse	1.27	1.09
		Powerhouse Renovations	4.40	4.00
		Spillway	1.59	1.50
		Water Control Systems	2.07	1.84
		Roads & Site Improvements	2.33	2.39
Turbines And Generators	2.18	Turbines & Generators	1.82	1.60
		Governors & Excitation System	2.11	1.88
		Licence Renewal	2.00	2.00
Accessory Station Equipment	2.30	A/C Electrical Power Systems	2.10	1.99
		Instrumentation, Control & D/C Systems	4.43	4.92
		Auxiliary Station Processes	2.59	2.58
Other	2.01	Support Buildings	1.73	1.44
		Support Building Renovations	5.50	5.00
POINTE DU BOIS		**POINTE DU BOIS**		
Civil	11.75	Dams, Dykes & Weirs	3.68	3.16
		Powerhouse	4.41	3.91
		Powerhouse Renovations	5.24	4.84
		Spillway - Original	10.76	8.41
		Water Control Systems	3.35	2.81
		Roads & Site Improvements	3.36	2.87
Turbines And Generators	11.59	Turbines & Generators	4.04	3.53
		Governors & Excitation System	5.24	5.04
		Licence Renewal	4.76	4.76
Accessory Station Equipment	11.48	A/C Electrical Power Systems	4.58	4.16
		Instrumentation, Control & D/C Systems	5.12	5.14
		Auxiliary Station Processes	4.03	3.68
Other	11.46	Support Buildings	2.93	2.41
		Support Building Renovations	5.50	5.00
		Spillway - New	1.47	1.33
SEVEN SISTERS		**SEVEN SISTERS**		
Civil	1.31	Dams, Dykes & Weirs	1.03	0.88
		Powerhouse	0.90	0.75
		Powerhouse Renovations	4.40	4.00
		Spillway	1.17	1.22
		Water Control Systems	1.80	1.33
		Roads & Site Improvements	1.84	1.26
Turbines And Generators	1.88	Turbines & Generators	1.64	1.49
		Governors & Excitation System	2.00	2.00
		Licence Renewal	2.00	2.00
Accessory Station Equipment	2.34	A/C Electrical Power Systems	1.91	1.76
		Instrumentation, Control & D/C Systems	3.73	3.50
		Auxiliary Station Processes	2.13	2.03
Other	2.14	Support Buildings	1.74	1.70
		Support Building Renovations	5.50	5.00
SLAVE FALLS		**SLAVE FALLS**		
Civil	1.90	Dams, Dykes & Weirs	1.69	1.54
		Powerhouse	1.58	1.42
		Powerhouse Renovations	4.40	4.00
		Spillway	1.87	2.03
		Water Control Systems	2.18	2.04
		Roads & Site Improvements	2.20	2.27
Turbines And Generators	2.01	Turbines & Generators	1.79	1.68
		Governors & Excitation System	2.20	2.00
		Licence Renewal	2.00	2.00
Accessory Station Equipment	2.25	A/C Electrical Power Systems	2.21	2.30
		Instrumentation, Control & D/C Systems	4.72	5.41
		Auxiliary Station Processes	2.73	3.13
Other	2.42	Support Buildings	1.81	1.79
		Support Building Renovations	5.50	5.00

Appendix 5.7
Electric Depreciation Rates

Depreciable Group	Effective April 1, 2007	Depreciable Group	Effective April 1, 2011	Effective April 1, 2013
PINE FALLS		**PINE FALLS**		
Civil	1.55	Dams, Dykes & Weirs	1.17	1.07
		Powerhouse	0.83	0.71
		Powerhouse Renovations	4.40	4.00
		Spillway	1.60	1.94
		Water Control Systems	1.95	1.46
		Roads & Site Improvements	1.81	0.06
Turbines And Generators	1.91	Turbines & Generators	1.47	1.27
		Governors & Excitation System	2.20	2.00
		Licence Renewal	2.00	2.00
Accessory Station Equipment	2.07	A/C Electrical Power Systems	2.06	1.87
		Instrumentation, Control & D/C Systems	4.25	4.45
		Auxiliary Station Processes	2.54	2.43
Other	2.01	Support Buildings	1.61	1.62
		Support Building Renovations	5.50	5.00
Community Development Costs	1.90	Community Development Costs	1.17	1.17
MCARTHUR FALLS		**MCARTHUR FALLS**		
Civil	1.48	Dams, Dykes & Weirs	0.91	0.82
		Powerhouse	0.83	0.74
		Powerhouse Renovations	4.40	4.00
		Spillway	1.19	0.99
		Water Control Systems	2.06	1.81
		Roads & Site Improvements	1.99	1.79
Turbines And Generators	0.98	Turbines & Generators	1.06	0.53
		Governors & Excitation System	2.10	1.97
		Licence Renewal	2.00	2.00
Accessory Station Equipment	2.01	A/C Electrical Power Systems	1.90	1.48
		Instrumentation, Control & D/C Systems	4.29	3.61
		Auxiliary Station Processes	2.58	2.47
Other	2.25	Support Buildings	1.63	1.63
		Support Building Renovations	5.50	5.00
KELSEY		**KELSEY**		
Civil	1.32	Dams, Dykes & Weirs	1.05	0.96
		Powerhouse	0.89	0.80
		Powerhouse Renovations	4.40	4.00
		Spillway	1.34	1.20
		Water Control Systems	2.09	1.81
		Roads & Site Improvements	2.05	1.78
Turbines And Generators	1.61	Turbines & Generators	1.68	1.63
		Governors & Excitation System	2.14	2.01
		Licence Renewal	2.00	2.00
Accessory Station Equipment	2.04	A/C Electrical Power Systems	2.03	1.77
		Instrumentation, Control & D/C Systems	4.58	4.61
		Auxiliary Station Processes	2.63	2.55
Other	2.25	Support Buildings	1.67	1.70
		Support Building Renovations	5.50	5.00
GRAND RAPIDS		**GRAND RAPIDS**		
Civil	1.21	Dams, Dykes & Weirs	0.98	0.88
		Powerhouse	0.91	0.81
		Powerhouse Renovations	4.40	4.00
		Spillway	1.30	1.21
		Water Control Systems	1.79	1.55
		Roads & Site Improvements	1.68	1.21
Turbines And Generators	1.83	Turbines & Generators	1.64	1.57
		Governors & Excitation System	2.13	2.00
		Licence Renewal	2.00	2.00
Accessory Station Equipment	1.96	A/C Electrical Power Systems	2.07	1.96
		Instrumentation, Control & D/C Systems	4.08	3.16
		Auxiliary Station Processes	2.62	2.68
Other	2.54	Support Buildings	1.66	1.69
		Support Building Renovations	5.50	5.00
Community Development Costs	1.38	Community Development Costs	1.16	1.16

Appendix 5.7
Electric Depreciation Rates

Depreciable Group	Effective April 1, 2007	Depreciable Group	Effective April 1, 2011	Effective April 1, 2013
KETTLE		**KETTLE**		
Civil	1.21	Dams, Dykes & Weirs	0.86	0.79
		Powerhouse	0.87	0.79
		Powerhouse Renovations	4.40	4.00
		Spillway	1.33	1.29
		Water Control Systems	1.55	1.02
		Roads & Site Improvements	2.14	2.17
Turbines And Generators	1.58	Turbines & Generators	1.48	1.29
		Governors & Excitation System	1.66	1.17
		Licence Renewal	2.00	2.00
Accessory Station Equipment	1.95	A/C Electrical Power Systems	2.04	1.92
		Instrumentation, Control & D/C Systems	4.11	3.30
		Auxiliary Station Processes	2.44	2.15
Other	2.01	Support Buildings	1.46	1.28
		Support Building Renovations	5.50	5.00
LAURIE RIVER		**LAURIE RIVER**		
Civil	1.92	Dams, Dykes & Weirs	3.47	3.02
		Powerhouse	4.25	3.80
		Powerhouse Renovations	5.00	4.55
		Spillway	3.88	3.49
		Water Control Systems	3.84	3.39
		Roads & Site Improvements	4.01	3.63
Turbines And Generators	2.06	Turbines & Generators	4.49	4.04
		Governors & Excitation System	4.70	4.26
		Licence Renewal	4.55	4.55
Accessory Station Equipment	2.24	A/C Electrical Power Systems	4.08	3.70
		Instrumentation, Control & D/C Systems	7.23	7.30
		Auxiliary Station Processes	4.30	4.03
Other	2.43	Support Buildings	3.75	3.34
		Support Building Renovations	5.50	5.00
JENPEG		**JENPEG**		
Civil	1.25	Dams, Dykes & Weirs	0.92	0.86
		Powerhouse	0.89	0.83
		Powerhouse Renovations	4.40	4.00
		Spillway	1.42	1.45
		Water Control Systems	2.02	1.61
		Roads & Site Improvements	2.12	1.98
Turbines And Generators	1.66	Turbines & Generators	1.63	1.51
		Governors & Excitation System	2.20	2.00
		Licence Renewal	2.00	2.00
Accessory Station Equipment	1.93	A/C Electrical Power Systems	2.05	1.77
		Instrumentation, Control & D/C Systems	4.53	4.38
		Auxiliary Station Processes	2.66	2.54
Other	1.58	Support Buildings	1.67	1.65
		Support Building Renovations	5.50	5.00
LAKE WINNIPEG REGULATION		**LAKE WINNIPEG REGULATION**		
Civil	1.41	Dams, Dykes & Weirs	0.82	0.76
Water Channels	1.33			
		Licence Renewal	2.20	2.00
Community Development Costs	1.12	Community Development Costs	0.94	0.94
CHURCHILL RIVER DIVERSION		**CHURCHILL RIVER DIVERSION**		
Civil	1.35	Dams, Dykes & Weirs	0.88	0.83
Water Channels	1.17	Spillway	1.47	1.50
		Water Control Systems	2.21	1.80
		Roads & Site Improvements	2.21	1.94
		Licence Renewal	2.00	2.00
		A/C Electrical Power Systems	2.21	1.94
		Instrumentation, Control & D/C Systems	4.82	3.66
		Auxiliary Station Processes	2.75	2.88
		Support Buildings	1.69	1.75
		Support Building Renovations	5.50	5.00
Community Development Costs	1.09	Community Development Costs	0.93	0.93

Appendix 5.7
Electric Depreciation Rates

Depreciable Group	Effective April 1, 2007	Depreciable Group	Effective April 1, 2011	Effective April 1, 2013
LONG SPRUCE		**LONG SPRUCE**		
Civil	1.24	Dams, Dykes & Weirs	0.90	0.83
		Powerhouse	0.90	0.83
		Powerhouse Renovations	4.40	4.00
		Spillway	1.43	1.45
		Water Control Systems	2.04	1.62
		Roads & Site Improvements	2.10	1.88
Turbines And Generators	1.67	Turbines & Generators	1.63	1.51
		Governors & Excitation System	2.19	2.09
		Licence Renewal	2.00	2.00
Accessory Station Equipment	1.69	A/C Electrical Power Systems	2.09	1.85
		Instrumentation, Control & D/C Systems	4.37	3.36
		Auxiliary Station Processes	2.63	2.36
Other	2.32	Support Buildings	1.69	1.75
		Support Building Renovations	5.50	5.00
LIMESTONE		**LIMESTONE**		
Civil	1.24	Dams, Dykes & Weirs	0.90	0.85
		Powerhouse	0.91	0.85
		Powerhouse Renovations	4.40	4.00
		Spillway	1.45	1.59
		Water Control Systems	2.17	1.96
		Roads & Site Improvements	2.17	2.11
Turbines And Generators	1.60	Turbines & Generators	1.68	1.61
		Governors & Excitation System	2.17	2.01
		Licence Renewal	2.00	2.00
Accessory Station Equipment	2.03	A/C Electrical Power Systems	2.17	2.11
		Instrumentation, Control & D/C Systems	4.67	4.67
		Auxiliary Station Processes	2.71	2.67
Other	2.23	Support Buildings	1.68	1.68
		Support Building Renovations	5.50	5.00
		WUSKWATIM		
		Dams, Dykes & Weirs	0.88	0.80
		Powerhouse	0.88	0.80
		Powerhouse Renovations	4.40	4.00
		Spillway	1.47	1.33
		Water Control Systems	2.20	2.00
		Roads & Site Improvements	2.20	2.00
		Turbines & Generators	1.69	1.54
		Governors & Excitation System	2.20	2.00
		A/C Electrical Power Systems	2.20	2.00
		Instrumentation, Control & D/C Systems	4.78	4.35
		Auxiliary Station Processes	2.75	2.50
		Support Buildings	1.69	1.54
		Support Building Renovations	5.50	5.00
		INFRASTRUCTURE SUPPORTING GENERATION		
		Provincial Roads	2.30	2.10
		Town Site Buildings	1.71	1.81
		Town Site Buildings Renovations	5.94	5.59
		Town Site Other Infrastructure	2.49	2.50
THERMAL GENERATION		**THERMAL GENERATION**		
BRANDON UNIT 5 (COAL)		**BRANDON UNIT 5 (COAL)**		
Generation - Brandon Unit 5	3.71	Powerhouse	3.87	3.88
Thermal Life Assurance Brandon 5	4.85	Powerhouse Renovations	10.00	10.00
		Roads & Site Improvements	4.56	4.58
		Thermal Turbines & Generators	5.03	5.03
		Governors & Excitation System	5.07	5.08
		Licence Renewal	10.00	10.00
		Steam Generator & Auxiliaries	3.93	3.95
		A/C Electrical Power Systems	4.06	4.06
		Instrumentation, Control & D/C Systems	5.41	5.73
		Auxiliary Station Processes	4.67	4.70
		Support Buildings	4.25	4.26
		Support Building Renovations	10.00	10.00

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Appendix 5.7
Electric Depreciation Rates

Depreciable Group	Effective April 1, 2007	Depreciable Group	Effective April 1, 2011	Effective April 1, 2013
BRANDON UNITS 6 & 7		**BRANDON UNITS 6 & 7**		
		Powerhouse	1.65	1.57
		Powerhouse Renovations	4.40	4.00
		Thermal Turbines & Generators	2.12	2.04
		Governors & Excitation System	2.20	2.00
		Licence Renewal	2.00	2.00
Brandon Combustion Turbine	4.40	Combustion Turbine	4.05	3.99
		Combustion Turbine Overhauls	11.00	10.00
		A/C Electrical Power Systems	2.12	2.17
		Instrumentation, Control & D/C Systems	4.58	5.20
		Auxiliary Station Processes	2.64	2.80
SELKIRK		**SELKIRK**		
Generation - Selkirk 1 & 2	2.97	Powerhouse	0.93	0.00
Thermal Life Assurance Selkirk	2.46	Powerhouse Renovations	4.00	4.00
		Roads & Site Improvements	1.35	1.30
		Thermal Turbines & Generators	1.46	1.46
		Governors & Excitation System	2.00	2.10
		Licence Renewal	2.00	2.00
		Steam Generator & Auxiliaries	1.34	1.61
		A/C Electrical Power Systems	1.21	0.00
		Instrumentation, Control & D/C Systems	2.41	2.74
		Auxiliary Station Processes	1.64	1.56
		Support Buildings	1.06	1.04
		Support Building Renovations	5.00	5.00
DIESEL GENERATION		**DIESEL GENERATION**		
Structures & Improvements	7.27	Buildings	2.57	2.61
		Building Renovations	5.14	6.67
		Engines & Generators - Overhauls	20.00	20.00
Engines & Generators - Post 1987	12.78	Engines & Generators	1.88	2.03
Accessory Station Equipment	11.23	Accessory Station Equipment	3.07	2.73
		Fuel Storage & Handling	2.28	2.30
TRANSMISSION		**TRANSMISSION**		
Roads, Trails & Bridges	2.25	Roads, Trails & Bridges	2.51	2.63
Metal Towers	1.45	Metal Towers & Concrete Poles	1.51	1.19
Metal Towers [HVDC Purchase]	1.92			
Poles & Fixtures	2.60	Poles & Fixtures	2.49	1.82
Concrete Poles	1.41			
Ground Line Treatment	10.00	Ground Line Treatment	10.00	10.00
Conductor & Devices	1.85	Overhead Conductor & Devices	1.62	1.38
Conductor & Devices [HVDC Purchase]	2.37			
Underground Conductor & Devices	2.38	Underground Cable & Devices	2.23	2.19
SUB-STATION		**SUB-STATIONS**		
Structures & Improvements	1.66	Buildings	1.49	1.47
Structures & Improvements	1.87	Building Renovations	5.00	4.52
Roads, Trails & Bridges	2.18	Roads, Steel Structures & Civil Site Work	2.10	1.94
Poles & Fixtures	3.36	Poles & Fixtures	3.25	2.66
Serialized Equipment	2.99	Power Transformers	2.21	2.28
		Other Transformers	3.09	2.91
		Interrupting Equipment	2.41	2.31
Accessory Station Equipment	2.47	Other Station Equipment	2.54	2.46
Supervisory Equipment	5.40	Electronic Equipment & Batteries	4.76	4.50
		Synchronous Condensers & Unit Transformers	1.68	1.64
Serialized Equipment - HVDC System	3.79	Synchronous Condenser Overhauls	7.43	7.67
Serialized Equipment [HVDC Purchase]	2.71	HVDC Convertor Equipment	4.13	3.10
Accessory Station Equipment - HVDC System	4.07	HVDC Serialized Equipment	4.18	3.51
Accessory Station Equipment [HVDC Purchase]	9.37	HVDC Accessory Station Equipment	2.85	2.34
Supervisory Equipment - HVDC System	5.01	HVDC Electronic Equipment & Batteries	4.66	3.88

Appendix 5.7
Electric Depreciation Rates

Depreciable Group	Effective April 1, 2007
SUB-TRANSMISSION & DISTRIBUTION	
Roads, Trails & Bridges [Sub-Trans.]	1.97
Metal Towers [Sub-Trans.]	2.91
Poles, Conductor & Attachments [Sub-Trans.]	3.68
Poles, Conductor & Attachments [Distribution]	4.54
Groundline Treatment	10.00
Underground Conductor & Devices [Sub-Trans.]	3.35
Underground Conductor & Devices [Distribution]	2.44
Serialized Equipment [Sub-Transmission]	6.01
Serialized Equipment [Distribution]	5.09
Services	5.03
Street Lighting	2.49
DISTRIBUTION - METERS	
Meters	3.47
Metering Transformers	1.17
COMMUNICATION	
Structures & Improvements	1.85
Fibre Optic Cable	2.59
Communication & Control Equipment	6.01
Fibre Optic Electronics	6.71
MOTOR VEHICLES	
Passenger Vehicles	7.34
Light Trucks	9.10
Heavy Trucks	6.08
Construction Equipment	4.57
Large Soft-Track Equipment	3.39
Trailers	2.00
Miscellaneous Vehicles	11.79
BUILDINGS	
Buildings - Wood	1.69
Buildings - Concrete	1.99
Buildings - Metal	1.88
Buildings - 360 Portage	1.18
GENERAL EQUIPMENT	
Tools, Shop & Garage Equipment	6.67
Computer Equipment	20.00
Office Furniture & Equipment	6.67
Hot Water Tanks	6.67
Bill Inserter	14.29
Fire Retardant Clothing	20.00
INTANGIBLE ASSETS	
Easements	1.33
Computer Application	10.00
COMPOSITE (WEIGHTED AVERAGE) RATE	**2.95**

Depreciable Group	Effective April 1, 2011	Effective April 1, 2013
DISTRIBUTION - 66 kV & BELOW		
Underground Duct & Conduit - Concrete	2.29	2.35
Underground Duct - Roof	2.08	2.31
Metal Towers	1.99	1.39
Poles & Fixtures	2.10	1.41
Overhead Conductor & Devices	1.98	1.54
Ground Line Treatment	9.58	9.58
Underground Cable & Devices - 66 Kv	1.48	1.60
Underground Cable & Devices - Primary	1.69	1.69
Underground Cable & Devices - Secondary	2.21	2.21
Serialized Equipment - Overhead	2.86	2.49
Serialized Equipment - Underground	2.62	2.43
DSC - High Voltage Transformers	2.19	2.50
Electronic Equipment	10.00	10.00
Services	4.38	3.01
Street Lighting	3.04	2.61
DISTRIBUTION METERS		
Meters - Electronic	6.10	7.89
Meters - Analog	13.54	14.38
Metering Transformers	2.20	2.76
COMMUNICATION		
Buildings	1.67	1.69
Building Renovations	5.67	5.28
Building - System Control Centre	1.68	1.70
Communication Towers	1.82	2.08
Fibre Optic & Metallic Cable	3.06	3.95
Carrier Equipment	7.68	8.85
Operational IT Equipment	22.97	19.99
Mobile Radio, Telephone & Video Conf.	10.24	8.19
Operational Data Network	14.10	13.19
Power System Control	11.16	10.68
MOTOR VEHICLES		
Passenger Vehicles	11.09	13.67
Light Trucks	7.85	8.79
Heavy Trucks	5.83	7.17
Construction Equipment	5.27	6.30
Large Soft-Track Equipment	4.28	4.97
Trailers	1.94	2.18
Miscellaneous Vehicles	5.93	6.99
BUILDINGS		
Buildings - General	1.59	1.58
Building Renovations	7.14	6.66
Building - 360 Portage - Civil	1.00	1.06
Building - 360 Portage - Electro/Mechanical	2.21	3.10
GENERAL EQUIPMENT		
Tools, Shop & Garage Equipment	7.74	7.74
Computer Equipment	28.48	28.48
Office Furniture & Equipment	4.81	4.81
Hot Water Tanks	21.20	21.20
INTANGIBLE ASSETS		
Easements	1.28	1.49
Computer Development - Major Systems	9.37	10.43
Computer Development - Small Systems	10.00	10.00
Computer Software - General	23.36	19.76
Computer Software - Communic./Operational	13.93	13.93
Operational Sys. Major Software EMS/SCADA	23.35	23.08
COMPOSITE (WEIGHTED AVERAGE) RATE	**2.59**	**2.44**

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PUB/MH II-34

Reference: Appendix 5.7 P. 6 & 7, 2012 Annual Report.

a) **Please confirm that effective April 1, 2013 MH will be increasing the life expectancy for dams, dykes, Weirs and Powerhouses to approximately 120 years with respect to the majority of MH's generation stations. Please provide a listing of the stations impacted, the in-service dates of each station, the proposed new life expectancy and previous life expectancy for each station.**

ANSWER:

As disclosed in Note 1 b) and Note 2 to the Consolidated Financial Statements included in the 2012 Annual Report, Manitoba Hydro implemented changes to depreciation rates, component breakdown and average service lives effective April 1, 2011, for the 2011/12 fiscal year. The new depreciation rates were calculated by Gannett Fleming using the ASL procedure for group depreciation with the revised life span dates shown in Schedule 1 to the letter from Gannett Fleming dated January 13, 2012, which is included in Appendix 5.7.

For hydraulic generating stations, the Civil component was broken down into a number of new components, and an average service life was established for each new component as shown in the following table. These average service lives apply to all hydraulic generating stations.

Previous Approved In use until March 31, 2011 Civil Components	Average Service Life	**Revised Effective April 1, 2011** Civil Components	Average Service Life
Civil	100	Dams, Dykes & Weirs	125
		Powerhouse	125
		Powerhouse Renovations	25
		Spillway	75
		Water Control Systems	50
		Roads & Site Improvements	50
Composite Weighted Average	100	Composite Weighted Average	104

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In addition to the average service life applicable to the depreciable components, each hydraulic generating station has been assigned a life span date. The life span date is used in recognition that there is an overall constraining factor impacting the usefulness of the assets to the Corporation. Except for the Laurie River generating station, the life expectancy of the Powerhouse has been identified as the predominant constraining factor. When the powerhouse itself reaches end of life, all assets contained in the Powerhouse will be retired along with the Powerhouse, regardless of whether the contained items have reached their own end of life. For purposes of establishing a revised life span date, the overall life of a powerhouse is assumed to be 140 years, with exceptions made where conditions at a specific generating station differ from those generally observed.

For the Laurie River, the life expectancy of the turbines and generators has been identified as the predominant constraining factor. It is much less likely that it will be economically feasible to replace the turbines and generators at Laurie River when they reach end of life, as the station produces much less electricity than the other, larger generating stations.

Generating station assets are depreciated over the lesser of the average service life and the remaining years to the life span date.

The following table provides the original in-service date and requested life expectancy information for each hydraulic generating station:

Generating Station	In-Service Date for First Unit	Previous Approved In use until March 31, 2011 Life Span Date (March 31)	Previous Approved Overall Life Span (Years)	Revised Effective April 1, 2011 Life Span Date (March 31)	Revised Life Span (Years)
Great Falls	Jan 3, 1923	2052	129	2063	140
Pointe Du Bois	Oct 16, 1911	2015	103	2031	119
Seven Sisters	Jun 3, 1931	2052	120	2072	140
Slave Falls	Sep 1, 1931	2063	131	2072	140
Pine Falls	Dec 12, 1951	2052	100	2092	140
Mcarthur Falls	Nov 26, 1954	2055	100	2095	140
Kelsey	Jun 22, 1960	2062	101	2101	140
Grand Rapids	Sep 1, 1965	2067	101	2091	125
Kettle	Jan 1, 1971	2072	101	2111	140
Laurie River	Sep 18, 1952	2056	103	2032	79
Jenpeg	Jul 1, 1977	2078	100	2118	140
Long Spruce	Oct 1, 1977	2078	100	2118	140
Limestone	Sep 8, 1990	2092	101	2131	140
Wuskwatim	Jan 31, 2012 *			2152	140

* Wuskwatim: Expected in-service date at the time the depreciation study was conducted

Exceptions to the general 140 year life span were made for the following generating stations:

- **Pointe du Bois**: The revised life span date is based on the timing of planned capital work for the Point du Bois Powerhouse Rebuild as included in CEF11-2.
- **Grand Rapids**: The life span has been reduced to reflect differences in the make-up of the concrete used in the construction of the powerhouse, which is deteriorating at a faster rate than at other generating stations.
- **Laurie River**: The revised life span is based on the turbines and generators, and has been established as 2032.

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PUB/MH II-34

Reference: Appendix 5.7 P. 6 & 7, 2012 Annual Report.

c) **Please provide a summary of the capital expenditures on upgrades and rehabilitation MH has undertaken on each of its hydraulic generating stations.**

ANSWER:

Please refer to the following table for a list of the significant (greater than or equal to $1 million) upgrades and refurbishments made to Dams, Dykes, Weirs and Powerhouses at Manitoba Hydro's hydraulic generating stations. For Pointe du Bois and Slave Falls generating stations, the table includes modifications made since the acquisition of Winnipeg Hydro in 2003:

Component	Year(s)	$ in Millions	Capital Project
Great Falls Generating Station:			
Dams, Dykes & Weirs	1986	8.0	Rehabilitaion - Non-Overflow Dams
	1986	2.7	Rehabilitaion - Dykes
	1986	2.0	Rehabilitaion - Rockfill Dam, East Corewall and Spillway
Powerhouse	1986	4.5	Rehabilitation - Powerhouse
Pointe du Bois:			
Dams, Dykes & Weirs	2004-2005	4.6	East Forebay Wall Anchor
	2006-2008	6.5	Dam Safety Deficiencies
Powerhouse	2005-2010	3.9	Dam Safety Deficiencies
Seven Sisters:			
Dams, Dykes & Weirs	1984	1.9	Rehabilitation - Raising Earth Dykes
	1984	17.8	Rehabilitation - Overflow & Non-Overflow Dams
	2002-2010	2.7	Dam Safety Program
Powerhouse	1997-2000	3.3	Major Concrete Rehabilitaion (Powerhouse)
Slave Falls:			
Dams, Dykes & Weirs	no significant modifications have been made		
Powerhouse	2005-2010	1.3	Fall Protection Program
Pine Falls:			
Dams, Dykes & Weirs	1998-2011	12.2	Winnipeg River Bank Protection Program
Powerhouse	no significant modifications have been made		

Component	Year(s)	$ in Millions	Capital Project
McArthur Falls:			
Dams, Dykes & Weirs	2005-2011	2.2	Dam Safety Program
Powerhouse	no significant modifications have been made		
Kelsey:			
Dams, Dykes & Weirs	1998-2010	5.4	Dam Safety Upgrades
	2010	1.8	Kelsey Spillway Stability Anchoring
Powerhouse	no significant modifications have been made		
Grand Rapids:			
Dams, Dykes & Weirs	2005-2011	13.5	Dam Safety Program
Powerhouse	no significant modifications have been made		
Kettle:			
Dams, Dykes & Weirs	no significant modifications have been made		
Powerhouse	2007	2.6	Roof Replacement
Laurie River:			
Dams, Dykes & Weirs	no significant modifications have been made		
Powerhouse	1995	2.6	Civil Deficencies - Phase 1
	2003-2008	4.7	Civil Deficencies - Phase 2
Jenpeg:			
Dams, Dykes & Weirs	2004-2005	3.8	Kiskitto Ctl.Structure & Dyke 7-2
Powerhouse	2005-2010	1.4	Fall Protection Program
Long Spruce:			
Dams, Dykes & Weirs	no significant modifications have been made		
Powerhouse	2009	2.9	Roof Replacement
Limestone:			
Dams, Dykes & Weirs	no significant modifications have been made		
Powerhouse	2009	2.7	Roof Replacement

Facility Civil Works	Remaining Life (yrs) 2005	 2010	Condition (Garnett/Fleming Knowledge)	5 Yrs. Later Life Extension Years
Limestone G.S.	76	97	What changed 2009 Roof $2.7M	+26
Long Spruce G.S.	63	85	2009 Roof $2.9M	+27
Kettle G.S.	57	79	2007 Roof $2.6M	+27
Kelsey G.S.	50	82	1998-2010 Rehab $7.2M	+37
JenPeg G.S.	63	88	Powerhouse rebuild & turbine deficiency 2004-10 $5.2M 2011 ?	+30
LWR Works	62	87	Erosions, Sediment surveys?	+30
CRD Works	62	87		+30
Grand Rapids G.S.	53	71	Generator failure/Licence changes ? Erosion/seepage ?	+33
Bipole I & II (HVDC)				
Towers	54	60	Grosse Isle wind/foundation failures/future risk	+11
Conductors	43	44		+6
Converters	10	14		+9
Pointe Du Bois G.S.	9	22	Concrete deterioration 2005-10 Rehab $15.0M Maximum flood design	+18
Slave Falls G.S	56	61	2005-10 Rehab $1.5M	+10
Seven Sisters G.S.	44	59	1984-2000 Rehab $24.7M	+20
MacArthur G.S.	45	69	2005-11 Rehab $2.2M	+30
Great Falls G.S.	44	51	1986 Rehab $16.7	+12
Pine Falls G.S.	42	77	1998-2011 Rehab $12.2M	+40
Brandon SCCT(s)	23	54	?	+36

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MIPUG/MH I-15

Subject: Appendix 5.7 Depreciation Study

p) Please update PUB/MH-1-37(a) Revised re: depreciation expenses for actuals and forecasts through 2013/14. For each year, please separately identify the impacts of addition of assets; Wuskwatim; the new depreciation study lives; the impacts of the adoption of the ELG approach; and the impact of the elimination of asset retirement costs.

ANSWER:

For the requested update to 2008/09 Information Request PUB/MH I-37(a), please refer to PUB/MH I-81(a).

The attached schedule identifies the incremental impact of the specified items for each of the years included in PUB/MH I-81(a).

D A

MANITOBA HYDRO
DEPRECIATION AND AMORTIZATION EXPENSE

	2007/08 Actual	Net Additions	2008/09 Actual	Net Additions	2009/10 Actual	Net Additions	2010/11 Actual	Year over Year Change: Net Additions	Year over Year Change: Depreciation Study: Component Reclass	Year over Year Change: Depreciation Study: Change in Asset Life	2011/12 Actual
Generation											
Hydraulic Generating Stations	68 451	2 460	70 911	3 399	74 310	1 818	76 128	3 692	(352)	(4 404)	75 064
Thermal Generating Stations	17 170	106	17 276	336	17 612	(7 842)	9 771	1 180	(426)	(1 845)	8 680
Amortization of Planning Studies	2 366	(2 366)	-	-	-	-		-	-	-	-
Demand Side Management	11 357	7 800	19 157	2 907	22 064	1 930	23 994	2 197	-	-	26 191
Diesel Generating Stations	4 067	(134)	3 933	(381)	3 552	139	3 691	1 685	-	(4 017)	1 359
Amortization of Contributions	(2 774)	(22)	(2 796)	-	(2 796)	-	(2 796)	(247)	-	2 325	(718)
	$ 100 637	$ 7 844	$ 108 481	$ 6 262	$ 114 743	$ (3 955)	$ 110 788	$ 8 507	$ (778)	$ (7 941)	$ 110 576
Transmission											
Transmission	14 120	197	14 317	11	14 328	143	14 471	74	-	(625)	13 920
Amortization of Contributions	(1 631)	(6)	(1 638)	-	(1 638)	9	(1 629)	1	-	271	(1 357)
	$ 12 489	$ 191	$ 12 680	$ 11	$ 12 690	$ 152	$ 12 842	$ 75	$ -	$ (354)	$ 12 563
Stations											
Substations	70 616	1 896	72 512	1 611	74 123	2 624	76 747	5 060	1 909	(4 558)	79 157
Transformers	3 681	(1 393)	2 288	(167)	2 121	(468)	1 653	316	-	(278)	1 691
Amortization of Contributions	(1 461)	(1)	(1 462)	(2)	(1 464)	(6)	(1 470)	(29)	-	251	(1 247)
	$ 72 836	$ 502	$ 73 338	$ 1 442	$ 74 780	$ 2 150	$ 76 930	$ 5 347	$ 1 909	$ (4 585)	$ 79 601
Distribution											
Subtransmission Lines	8 905	261	9 166	303	9 469	423	9 892	714	-	(4 632)	5 974
Distribution Lines	72 410	5 320	77 730	4 949	82 679	4 515	87 194	4 999	-	(36 646)	55 547
Meters & Metering Transformers	1 551	46	1 597	(7)	1 590	25	1 615	(176)	-	2 766	4 205
Amortization of Contributions	(9 769)	(411)	(10 180)	(263)	(10 443)	(267)	(10 710)	(401)	-	6 337	(4 774)
	$ 73 097	$ 5 215	$ 78 312	$ 4 983	$ 83 295	$ 4 696	$ 87 991	$ 5 136	$ -	$ (32 175)	$ 60 952
Other											
Communications	17 636	1 837	19 473	1 474	20 947	1 571	22 518	(7 768)	-	5 368	20 118
Motor Vehicles	8 275	416	8 691	69	8 760	740	9 500	1 736	-	(862)	10 374
Structures & Improvements	3 216	2 476	5 692	898	6 590	832	7 422	403	(1 131)	924	7 618
General Equipment	20 572	(2 898)	17 674	332	18 006	(834)	17 172	826	-	5 495	23 493
Computer Development	13 582	499	14 081	373	14 454	799	15 253	3 485	-	157	18 895
Affordable Energy Fund	625	816	1 441	1 617	3 058	410	3 468	4 004	-	-	7 472
Miscellaneous	2 701	(238)	2 463	532	2 995	(372)	2 623	797	-	-	3 420
Corporate Allocation	(2 093)	81	(2 012)	(127)	(2 139)	359	(1 780)	-	-	74	(1 706)
Target Adjustment									-		-
	$ 64 514	$ 2 989	$ 67 503	$ 5 168	$ 72 671	$ 3 505	$ 76 176	$ 3 483	$ (1 131)	$ 11 156	$ 89 684
Total Depreciation and Amortization Expense	$ 323 573	$ 16 741	$ 340 314	$ 17 865	$ 358 179	$ 6 547	$ 364 727	$ 22 548	$ -	$ (33 899)	$ 353 376

MANITOBA HYDRO
DEPRECIATION AND AMORTIZATION EXPENSE

	2011/12 Actual	Year over Year Change (Forecast)			2012/13 Forecast	Year over Year Change (Forecast)							2013/14 Forecast
		Net Additions	Wuskwatim	Depn Study Change in Asset Life		Net Additions	Wuskwatim	Depreciation Study Change in Asset Life	Depreciation Study ELG	Depreciation Study Removal of Net Salvage	IFRS Remove Indirect Overhead	Remove Rate Regulated Assets	
Generation													
Hydraulic Generating Stations	75 064	3 758	19 993	(1 561)	97 254	3 963	2 445	(414)	8 826	(14 222)	-	-	97 852
Thermal Generating Stations	8 680	7 397	-	(40)	16 036	441	-	(52)	1 333	(1 262)	-	-	16 496
Amortization of Planning Studies	-	-	-	-	-	-	-	-	-	-	-	-	-
Demand Side Management	26 191	2 474	-	-	28 664	2 731	-	-	-	-	-	(31 395)	-
Diesel Generating Stations	1 359	(173)	-	221	1 407	197	-	(154)	106	(123)	-	(64)	1 368
Amortization of Contributions	(718)	(602)	-	287	(1 033)	(135)	-	76	-	-	-	-	(1 092)
	$ 110 576	$ 12 854	$ 19 993	$ (1 094)	$ 142 328	$ 7 196	$ 2 445	$ (543)	$ 10 266	$ (15 608)	$ -	$ (31 459)	$ 114 624
Transmission													
Transmission	13 920	929	2 261	(115)	16 995	541	-	(25)	1 405	(4 737)	-	-	14 179
Amortization of Contributions	(1 357)	86	-	(87)	(1 358)	(20)	-	19	-	-	-	-	(1 360)
	$ 12 563	$ 1 015	$ 2 261	$ (202)	$ 15 636	$ 520	$ -	$ (6)	$ 1 405	$ (4 737)	$ -	$ -	$ 12 819
Stations													
Substations	79 157	5 206	3 261	(442)	87 181	3 453	-	(195)	4 743	(14 289)	-	-	80 893
Transformers	1 691	311	-	(19)	1 983	538	-	(30)	145	(436)	-	-	2 200
Amortization of Contributions	(1 247)	105	-	(93)	(1 235)	(16)	-	16	-	-	-	-	(1 235)
	$ 79 601	$ 5 622	$ 3 261	$ (554)	$ 87 929	$ 3 975	$ -	$ (209)	$ 4 888	$ (14 725)	$ -	$ -	$ 81 858
Distribution													
Subtransmission Lines	5 974	553	-	(312)	6 215	556	-	(224)	703	(1 827)	-	-	5 423
Distribution Lines	55 547	6 629	38	(2 394)	59 820	5 494	-	(2 214)	6 743	(17 534)	-	-	52 309
Meters & Metering Transformers	4 205	842	-	(28)	5 019	(14)	-	(26)	624	-	-	-	5 603
Amortization of Contributions	(4 774)	(812)	-	268	(5 318)	(551)	-	318	-	-	-	-	(5 551)
	$ 60 952	$ 7 212	$ 38	$ (2 467)	$ 65 736	$ 5 486	$ -	$ (2 147)	$ 8 069	$ (19 361)	$ -	$ -	$ 57 784
Other													
Communications	20 118	4 391	32	613	25 153	1 331	-	455	5 316	(2 622)	-	-	29 634
Motor Vehicles	10 374	(386)	-	(53)	9 935	342	-	(27)	1 760	-	-	-	12 010
Structures & Improvements	7 618	718	-	173	8 509	360	-	106	321	199	-	-	9 495
General Equipment	23 493	(642)	-	161	23 011	(1 361)	-	(424)	-	-	-	-	21 226
Computer Development	18 895	(2 473)	-	(46)	16 376	1 594	-	(52)	1 019	-	-	-	18 937
Affordable Energy Fund	7 472	1 398	-	-	8 870	(160)	-	-	-	-	-	-	8 710
Miscellaneous	3 420	339	-	-	3 760	(1 845)	-	-	-	-	-	(5 333)	(3 418)
Corporate Allocation	(1 706)	(1)	-	-	(1 707)	499	-	-	-	-	-	-	(1 208)
Target Adjustment	-	(5 163)	-	472	(4 691)	(4 408)	-	614	(737)	1 280	(221)	-	(8 163)
	$ 89 684	$ (1 820)	$ 32	$ 1 321	$ 89 217	$ (3 648)	$ -	$ 671	$ 7 679	$ (1 143)	$ (221)	$ (5 333)	$ 87 223
Total Depreciation and Amortization Expense	$ 353 376	$ 24 882	$ 25 584	$ (2 996)	$ 400 846	$ 13 530	$ 2 445	$ (2 234)	$ 32 307	$ (55 574)	$ (221)	$ (36 792)	$ 354 307

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Reference: **Appendix 5.7 Page 1&2, Depreciation Rates**

Preamble: **Gannet Flemming states that the requirements and implementation of IFRS are generally aligned with the appropriate and reasonable depreciation practices and procedures commonly used for regulatory purposes.**

a) **Please indicate the depreciation methodology employed in other Canadian jurisdictions and in particular where Equal Life Group (ELG) has adopted for rate-setting purposes.**

ANSWER:

The following response was prepared by Gannett Fleming.

Please refer to the attachment document which provides a detailed listing the utilities throughout North America that are currently using the ELG procedure. Virtually all other utilities not on the attached list would be using the ASL procedure or would not yet have received authorization from their regulator to use the ELG procedure:

ED

DETAILED LIST OF UTILITIES THROUGHOUT NORTH AMERICA USING ELG PROCEDURE

Company Name	Approved by:
Allegheny Energy Supply, Inc.	Gannett Fleming cannot confirm that ELG has been approved
AltaGas Utilities Inc.	Alberta Utilities Commission
ATCO Gas	Alberta Utilities Commission
ATCO Electric	Alberta Utilities Commission
CenterPoint Energy - General (Oklahoma)	Oklahoma Corporation Commission Public Utility Division
CenterPoint Energy Arkansas	Arkansas Public Service Commission
CenterPoint Energy Arkla - General	Louisiana Public Service Commission
CenterPoint Energy Arkla - Services	Louisiana Public Service Commission
CenterPoint Energy Arkla Louisiana	Louisiana Public Service Commission
CenterPoint Energy Entex - Texas Division	Public Utility Commission of Texas
CenterPoint Energy Oklahoma	Oklahoma Corporation Commission Public Utility Division
Citizens Energy Group	Gannett Fleming can not confirm that ELG has been approved
Columbia Gas of Kentucky	Kentucky Public Service Commission
Duke Energy Indiana	Indiana Utility Regulatory Commission
Duke Energy Kentucky	Kentucky Public Service Commission
East Kentucky Power Cooperative	Kentucky Public Service Commission
Enmax Power Corporation	Alberta Utilities Commission
Entergy Arkansas, Inc.	Arkansas Public Service Commission
Entergy Gulf States Louisiana, LLC.	Louisiana Public Service Commission
Entergy Louisiana, LLC.	Louisiana Public Service Commission
Entergy Mississippi, Inc.	Mississippi Public Service Commission
Entergy Texas, Inc.	Public Utility Commission of Texas
FortisAlberta Utilities, Inc.	Alberta Utilities Commission
Kentucky Utilities	Kentucky Public Service Commission
Kokomo Gas and Fuel Company	Indiana Utility Regulatory Commission
Louisville Gas & Electric	Kentucky Public Service Commission
Newfoundland Power Limited	Newfoundland and Labrador Board of Commissioners of Public Utilities
Northern Indiana Fuel and Light Company Inc.	Indiana Utility Regulatory Commission
Northern Indiana Public Service Company	Indiana Utility Regulatory Commission
Northland Utilities (NWT) Limited	Northwest Territories Public Utilities Board

Company Name	Approved by:
Northland Utilities (Yellowknife) Limited	Northwest Territories Public Utilities Board
Nova Scotia Power, Inc.	Nova Scotia Utility and Review Board
Public Service Company of Colorado	Colorado Public Utilities Commission
Quilliq Power Corporation	Nunavut Utility Rates Review Council
UGI Penn Natural Gas, Inc.	Pennsylvania Public Utilities Commission
UGI Utilities, Inc. - Electric Division	Pennsylvania Public Utilities Commission
Union Light Heat and Power Co.	Kentucky Public Service Commission

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Reference: **Appendix 5.7 Page 1&2, Depreciation Rates**

Preamble: **Gannet Flemming states that the requirements and implementation of IFRS are generally aligned with the appropriate and reasonable depreciation practices and procedures commonly used for regulatory purposes.**

b) **Please illustrate how the use of the ASL method of depreciation versus ELG proposed in the application will impact revenue requirement in 2013/14, 2014/15 and 2015/16.**

ANSWER:

The use of the ASL method of depreciation versus ELG method of depreciation would decrease the depreciation expenses and resulting revenue requirement in 2013/14, 2014/15 and 2015/16 as follows:

	Depreciation Expense ($ 000's)		
MH11-2	**2014**	**2015**	**2016**
Use of ASL vs ELG	(32,307)	(33,315)	(35,078)

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Reference: **Appendix 5.7 Page 1&2, Depreciation Rates**

Preamble: **Gannet Flemming states that the requirements and implementation of IFRS are generally aligned with the appropriate and reasonable depreciation practices and procedures commonly used for regulatory purposes.**

c) **Please provide the composite weighted average rate by Class under the ASL versus ELG methodology.**

ANSWER:

Please refer to the following table:

Class	ASL [1] RATE (%)	ELG [2] RATE (%)
Generation		
Hydraulic Generation	1.48	1.40
Thermal Generation	3.44	3.45
Diesel Generation	2.42	2.39
Transmission	1.71	1.38
Substations	3.16	2.82
Distribution		
Distribution Lines [3]	2.41	2.00
Meters	8.88	9.99
Other		
Communication	5.90	6.49
Motor Vehicles	5.96	6.98
Buildings	2.03	2.14
General Equipment	14.28	14.28
Easements	1.28	1.49
Computer Software and Development	10.57	11.17
Depreciable Assets	**2.59**	**2.44**

[1] Appendix 5.7/Gannett Fleming Schedule 1 - Use of the ASL Methodology: Pages 1-8

[2] Appendix 5.7/Gannett Fleming Schedule 1: Pages III-4 - III-11

[3] Includes Sub-transmission Lines

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Reference: **Appendix 5.7 Page 1&2, Depreciation Rates**

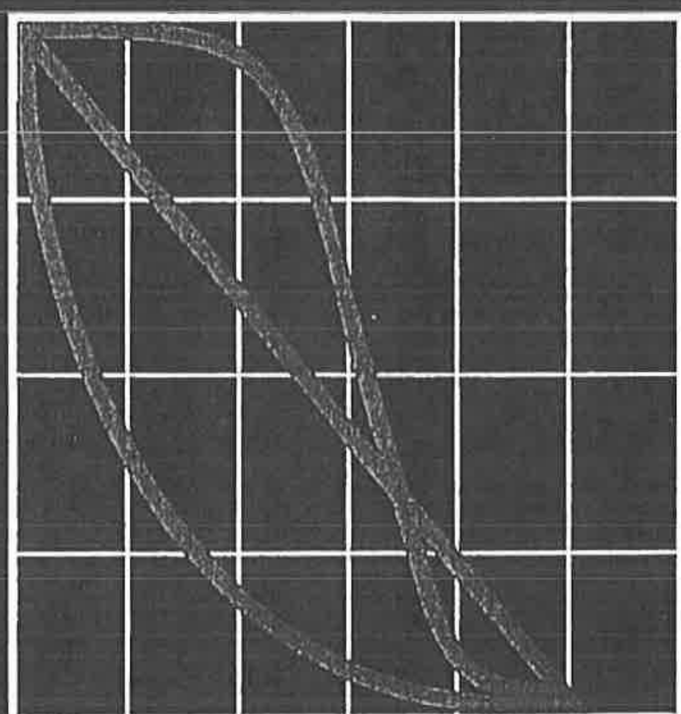
Preamble: **Gannet Flemming states that the requirements and implementation of IFRS are generally aligned with the appropriate and reasonable depreciation practices and procedures commonly used for regulatory purposes.**

d) Please indicate whether ASL is a methodology that can be used under IFRS.

ANSWER:

Please see Manitoba Hydro's response to CAC/MH I-47(a).

PUBLIC UTILITY DEPRECIATION PRACTICES



Public Utility

Depreciation Practices

August 1996

Compiled and Edited by

Staff Subcommittee on Depreciation of

The NARUC Finance and Technology Committee

of the

National Association of Regulatory Utility Commissioners

Published by
National Association of Regulatory Utility Commissioners
1201 Constitution Avenue, N.W., Suite 1102
Post Office Box 684
Washington, D.C. 20044
Telephone (202) 898-2200
Facsimile (202) 898-2213

CHAPTER XII

EQUAL LIFE GROUP DEPRECIATION RATES

Principles of Equal Life Grouping

The Equal Life Group (ELG) procedure is a refinement of the Vintage Group (VG) procedure whereby the vintages (generation) represented in the generation arrangement discussed in Chapter IX are subdivided using a survivor curve into subgroups having equal probable lives. ELG is not a recognized procedure in all regulated industries or by all regulatory authorities. However, it is recognized by the Federal Communications Commission (FCC), the Interstate Commerce Commission (ICC), and many state commissions.

Both the VG and ELG procedures are designed to charge to depreciation expense the cost of property installed in a single year (vintage) over the property's service life. Under the VG procedure, an average percentage rate is applied annually to the surviving property balance throughout the life of the vintage. The total cost of the vintage is fully allocated to expense when the last surviving unit in the vintage is retired.

The ELG procedure is designed to charge to depreciation expense the investment in <u>each</u> equal life group by the time <u>each</u> group is completely retired. For example, under ELG, if a group has a two-year life, its original capital costs should be allocated to expense by the end of two years, plant expected to live five years is completely expensed only at the end of five years. Under both the ELG and VG procedures, the <u>total</u> depreciation accruals representing 100% of the original capitalized costs are exactly the same at the end of the total life.

The ELG procedure is more sensitive than VG to retirement dispersion curves. Therefore, in order to calculate accurate depreciation accruals using the ELG procedure, detailed vintage plant mortality data must be maintained from which future mortality dispersion can be estimated. Without the long-term accumulation of data involving large numbers of units within each group, such accuracy may not be obtainable.

The ELG Procedure

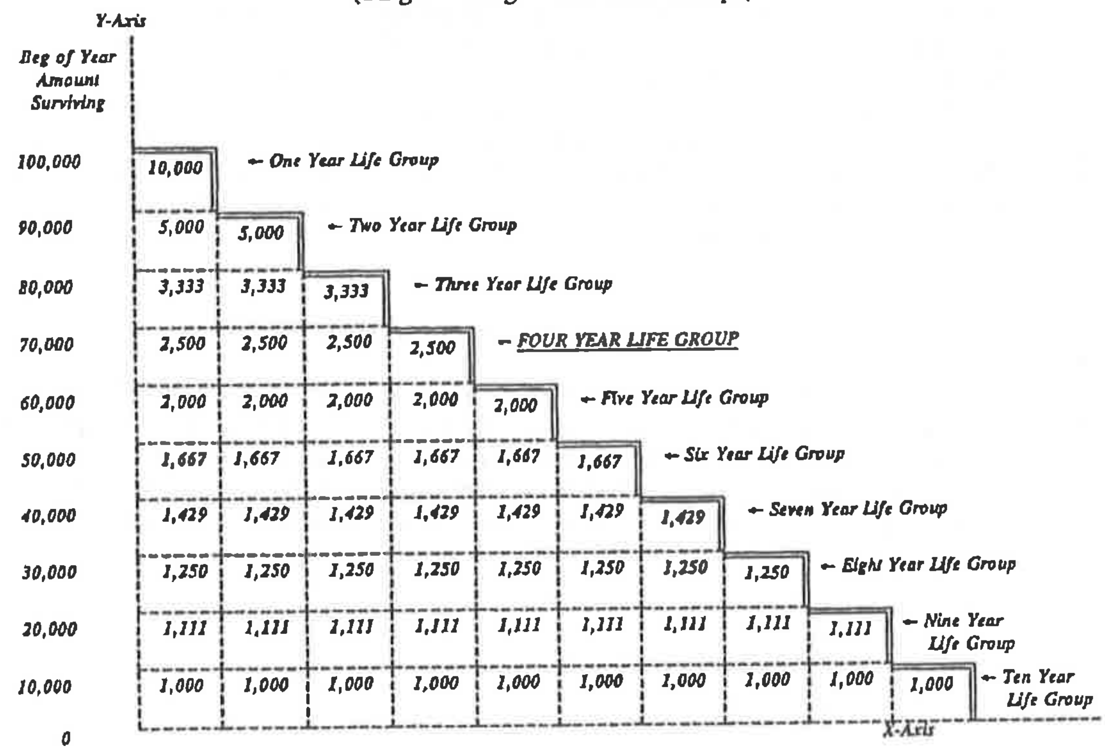
<u>Development of Equal Life Group Depreciation Rates</u>

In developing ELG depreciation rates, the life characteristics (average service life and survivor curve) are estimated using the same life analyses as used under the VG procedure. The initial plant investment is divided into equal life groups. While it is not possible to physically identify the individual units in each group, each group is treated as a unit of property and the total annual accrual for each vintage is the sum of the annual accrual for each equal life group remaining in service. In Table 12-5, the ELG depreciation rate for each age is the sum of each equal life group's annual accruals for the activity year divided by the vintage's amount surviving at the beginning of the year.

For example, Table 12-1 illustrates the ELG grouping and the calculation of depreciation accruals for a single vintage with ten equal life groups. The life of this table is determined by the area bounded by the x-axis, the y-axis, and the step-function.

TABLE 12-1

FIVE AND ONE-HALF YEAR STEP FUNCTION
(Single Vintage—Ten Life Groups)



AGE	0.5	1.5	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	SUM
TOTAL ACCRUALS	29,290	19,290	14,290	10,956	8,456	6,456	4,790	3,361	2,111	1,000	100,000
RATIO (ACCRUALS/ SURVIVORS)	29,290 / 100,000	19,290 / 90,000	14,290 / 80,000	10,956 / 70,000	8,456 / 60,000	6,456 / 50,000	4,790 / 40,000	3,361 / 30,000	2,111 / 20,000	1,000 / 10,000	
WL ELG Depr RATE (%)	29.3	21.4	17.9	15.7	14.1	12.9	12.0	11.2	10.6	10.0	

$$\text{Life} = (10{,}000 * \sum_{I=1}^{10} I) / 100{,}000 = 10{,}000\ (55) / 100{,}000 = 5.5 \text{ years.}$$

As shown in Table 12-1, each year 10,000 (dollars or units) is retired from the original 100,000. The items are subdivided through the use of a survivor curve into subgroups having equal probable lives. For example, consider the FOUR-YEAR LIFE GROUP near the center of Table 12-1. From this table it is observed that during the fourth year, the plant surviving declines by 10,000 from 70,000 to 60,000. Since this amount is forecast to retire after four years, the ELG procedure assigns one-fourth of the 10,000 accrual needed, or 2,500, to each of four years as shown in the boxes on Table 12-1.

Table 12-1 also details the calculation of the ELG depreciation accrual and the ELG whole life depreciation rate. While the equal life groups are determined horizontally, the accruals within each box are added vertically and the totals appear in the line designated TOTAL ACCRUALS. For example, the total accrual for the first year (age 0.5) is found by adding the first column of boxes (i.e., 10,000 + 5,000 + 3,333 + 2,500 + 2,000 + ... = 29,290). The second year accruals of 19,290 are found by adding the second column (age 1.5) of boxes (beginning with 5,000 since the group which lasted only one year has been retired). The remaining "Total Accruals" are similarly calculated. Note the sum of accruals for all ages is equal to the original 100,000. The whole life ELG rate (without salvage) is calculated by dividing the total accrual for each age by the plant surviving at that age. The quotients are shown in the RATIO row of Table 12-1 and the resulting depreciation rate is shown in the WL ELG Depr row. This row represents the WL ELG depreciation rate to be applied to the surviving vintage investment each year.

Sensitivity of ELG to Curve Shape

It should be clear from the preceding discussion and examination of Table 12-1 that the amounts to be divided into equal life groups depend directly upon the curve shape selected. To demonstrate the sensitivity of the ELG procedure to the selected curve shape, the ELG depreciation rates and accruals based on three different curve shapes, each with a five-year average life, are compared in Table 12-2; supporting calculations are in Table C.

TABLE 12-2

EFFECT OF CURVE SHAPE ON ACCRUALS

Activity Year	Age	Selected Curve Shape					
		Iowa L0		Iowa S1		Iowa R5	
		Accruals $	Rate %	Accruals $	Rate %	Accruals $	Rate %
1	0.5	30,632	31.5	25,099	25.1	20,491	20.5
2	1.5	20,475	23.5	22,201	22.9	20,491	20.5
3	2.5	14,372	19.2	18,188	20.5	20,491	20.5

The above three curves were chosen to illustrate the difference in depreciation accruals and rates resulting from using curves with significantly different shapes, from left modal to right modal and from low mode to high mode. Table 12-2 shows that the more left modal (maximum retirement frequency occurs prior to 100% of life) the curve is, the greater the accruals that occur in the early years using the ELG procedure.

Calculating Whole Life ELG Average Service Lives

In Table 12-1, the whole life ELG accruals and rates were developed by constructing a life table based on a step function and dividing each vintage into equal life groups. It is neither efficient nor convenient to construct such a life table each time an ELG rate is needed. Instead, the simple algorithm shown in Table 12-3 may be used to provide the same results as Table 12-1. Whereas a step function is useful in teaching, this function is rarely encountered. The life table values in Column B of Table 12-3 are based on the step function, but in actual practice it is more likely that an Iowa or Gompertz-Makeham (GM) curve representing the life characteristics of the plant being studied would be used.

Table 12-4 develops ELG whole life rates by age based on the 12-year GM curve used in Tables 9-1 and 9-3 of Chapter IX.

ELG True-Up Procedures

Even when a curve shape is chosen based on informed judgment, plant generally will not retire precisely at the time the projected life and dispersion patterns would suggest. Therefore, the difference between projected and actual retirement experience should be addressed. One way

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Table C-1: Depreciation Methods for Crown-Owned Canadian Utilities[166]

Utility	Depreciation Expense Calculation Method	Inclusion of Net Salvage in Depreciation Rates	Study Date
BC Hydro	Average Service Life Method[167]	Not Included - Future Removal and Site Restoration [FRSR] was removed from depreciation expense in 2004. The BCUC order that the $233 million in accumulated FRSR was removed from depreciation and a regulatory account was set up; where any incurred net salvage costs are deducted[168].	Gannett Fleming in 2006
BC Transmission Corporation	Average Service Life Method	Not included	Gannett Fleming in 2005
Newfoundland and Labrador Hydro	Average Service Life Method[169]	Not included[170]	Gannett Fleming in 2011
SaskPower	Average Service Life Method [171]	Not available	Gannett Fleming in 2011
Yukon Energy Corporation	Average Service Life Method[172]	Not Included - The Yukon Utilities Board Order 2005-12 directed a termination of any further appropriations to Yukon Energy's reserve for future removal and site restoration in 2005[173].	KPMG in 2012
Qulliq Energy Corporation	Average Service Life Method	Not Included	Gannett Fleming in 2011
Northwest Territories Power Corporation	Average Service Life Method	Included	Gannett Fleming in 2012

166 Information in table from MIPUG/MH II-9(c) of 2012 GRA unless otherwise referenced.

167 As per BC Hydro and Power Authority F2012 - 2014 Revenue Requirements Application; Appendix G: Review of BC Hydro's Implementation of International Financial Reporting Standards by Gannett Fleming. Page 8 (January 24, 2011).

168 British Columbia Utilities Commission British Columbia Hydro and Power Authority 2004/05 to 2005/06 Revenue Requirements Application. Page 157-158, 223 (October 29, 2004).

169 Newfoundland and Labrador Hydro Depreciation Study. Page 2-3 (September 7, 2011) http://www.pub.nf.ca/applications/NLH2012Depreciation/files/applic/NLH2012DepreciationApplication.pdf.

84 Newfoundland Hydro 2012 Depreciation Methodology Review. Direct Testimony of Pat Lee. Page 5 (October 3, 2012) http://www.pub.nf.ca/applications/NLH2012Depreciation/files/reports/IC-ExpertReport-Oct3-12.pdff.

171 MIPUG/MH II-9(c) of 2012 GRA and SaskPower 2013 Rate Application. Section 3.2.3: Depreciation & Amortization. Page 27 (June 2012) http://www.saskratereview.ca/images/docs/saskpower-2012/2013_rate_application.pdf.

172 Yukon Energy Corporation, 2012 General Rate Application. Tab 10: Depreciation Study by KPMG. Page 10-7 (March 1, 2012). http://yukonutilitiesboard.yk.ca/pdf/1338_YEC%202012_2013%20GRA%20FINAL_2012%2004%2027%20Tabs%201-11.pdf.

173 Yukon Utilities Board Order 2005-12. Directive 14. Page 3 (October 18, 2005) http://yukonutilitiesboard.yk.ca/pdf/109_boardorder2005_12.pdf.

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PUB/MH I-102

Reference: DSM Expenditures

Please provide details of the actual DSM expenditures by electric program for 2010/11, 2011/12, 2012/13 and 2013/14 breaking out the costs between internal and external costs.

ANSWER:

Expenditure Breakdown (1000s)	2010/11- Actual			2011/12 - Actual			2012/13 - Forecast			2013/14- Forecast		
	Total	Internal	External	Total	Internal	External	Total	Internal	External	Total	Internal	External
RESIDENTIAL												
Home Insulation	$1,365	$116	$1,249	$1,255	$149	$1,107	$1,143	$97	$1,046	$1,052	$90	$962
Appliances	$91	$84	$8	$1	$1	$0	$0	$0	$0	$0	$0	$0
Residential Lighting	$1,247	$279	$968	$312	$88	$224	$0	$0	$0	$0	$0	$0
New Homes	$210	$122	$88	$249	$146	$104	$512	$297	$215	$549	$318	$231
Seasonal LED Lighting	$1	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Lower Income Energy Efficiency	$131	$22	$110	$97	$27	$70	$397	$66	$331	$386	$64	$322
Water & Energy Saver	$457	$80	$377	$439	$74	$365	$876	$153	$723	$794	$138	$656
Fridge Recycling	$0	$0	$0	$1,479	$213	$1,267	$2,231	$2,046	$185	$2,144	$1.966	$178
	$3,503	$704	$2,799	$3,833	$697	$3,137	$5,158	$2,658	$2,500	$4,925	$2,577	$2,348
COMMERCIAL												
Commercial Lighting	$6,650	$1,821	$4,828	$6,336	$1,794	$4,542	$5,639	$1,545	$4,095	$5,086	$1,393	$3,693
Building Envelope	$1,474	$137	$1,337	$1,217	$144	$1,074	$1,060	$99	$961	$1,060	$99	$961
Agricultural Heat Pads	$99	$27	$72	$8	$8	$0	$5	$1	$4	$5	$1	$4
Parking Lot Controllers	$529	$64	$466	$281	$31	$250	$4	$0	$3	$0	$0	$0
Spray Valves	$5	$1	$5	$0	$0	$0	$1	$0	$1	$0	$0	$0
Internal Retrofit	$1,848	$196	$1,652	$744	$116	$628	$1,481	$157	$1,324	$1,181	$126	$1,056
Commercial Geothermal	$298	$96	$201	$290	$121	$169	$244	$79	$165	$256	$83	$173
Commercial Refrigeration	$170	$80	$91	$335	$131	$203	$201	$94	$107	$208	$97	$111
HVAC - Chillers	$315	$18	$297	$209	$17	$192	$143	$8	$135	$146	$8	$137
Custom	$230	$88	$143	$237	$135	$102	$155	$59	$96	$168	$64	$104
Commercial Building Optimization	$36	$26	$10	$39	$26	$13	$134	$97	$37	$140	$102	$38
City of Winnipeg Agreement	$79	$11	$68	-$45	-$13	-$32	$38	$5	$33	$0	$0	$0
Commercial Kitchen Appliances	$36	$12	$24	$31	$17	$14	$126	$41	$84	$146	$48	$98
Commercial Clothes Washers	$64	$41	$23	$63	$35	$28	$68	$44	$24	$71	$46	$26
New Construction	$307	$193	$114	$335	$220	$115	$1,144	$718	$426	$1,056	$662	$393
Power Smart Energy Manager	$65	$62	$3	$22	$22	$0	$0	$0	$0	$0	$0	$0
Network Energy Manager	$83	$70	$13	$23	$23	$0	$240	$203	$37	$266	$225	$41
Power Smart Shops	$142	$132	$10	$46	$46	$0	$0	$0	$0	$0	$0	$0
CO2 Sensors	$0	$0	$0	$0	$0	$0	$5	$0	$5	$5	$0	$5
	$12,431	$3,075	$9,356	$10,172	$2,874	$7,298	$10,689	$3,152	$7,537	$9,794	$2,954	$6,840
INDUSTRIAL												
Performance Optimization	$2,768	$361	$2,407	$2,932	$389	$2,543	$2,736	$357	$2,379	$2,736	$357	$2,379
Emergency Preparedness	$7	$7	$0	$1	$1	$0	$727	$710	$17	$1,532	$1,496	$36
	$2,775	$368	$2,407	$2,933	$390	$2,543	$3,463	$1,067	$2,396	$4,268	$1,853	$2,415
CUSTOMER SELF-GENERATION												
Bioenergy Optimization	$1,605	$135	$1,469	$1,721	$183	$1,538	$4,215	$356	$3,859	$4,342	$366	$3,976
RATE/LOAD MANAGEMENT												
Curtailable Rates	$5,741	$7	$5,734	$5,788	$9	$5,779	$5,952	$7	$5,945	$5,952	$7	$5,945
Option 1 & CSI	$1,795	$1,456	$339	$2,034	$1,679	$354	$3,041	$2,467	$574	$3,040	$2,466	$574
Support Activity & Continency	$1,513	$627	$885	$1,746	$795	$951	$1,891	$784	$1,107	$2,391	$992	$1,400
Total Utility Cost - Electric	**$29,362**	**$6,372**	**$22,990**	**$28,227**	**$6,627**	**$21,600**	**$34,409**	**$10,490**	**$23,918**	**$34,712**	**$11,215**	**$23,497**

October 2011

2011 Power Smart Plan

Power Smart Planning, Evaluation & Research Department
Customer Care & Marketing Business Unit

Manitoba Hydro
POWER SMART

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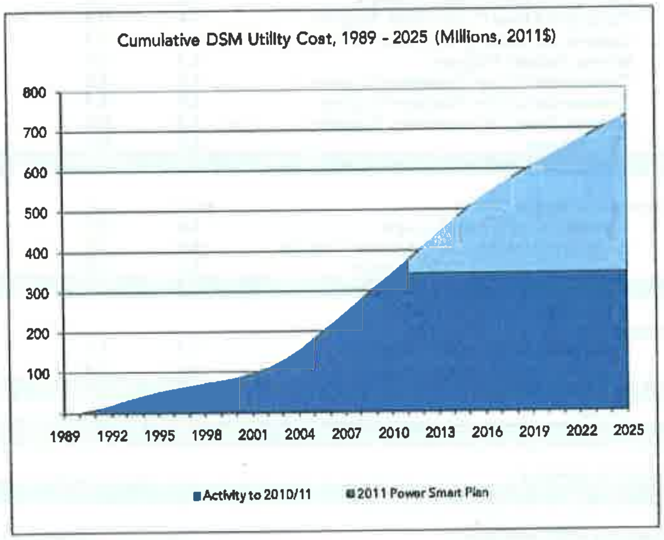
2.2 Electric DSM Utility Investment

The following table provides the projected annual electric DSM investment and cumulative totals to 2025/26 broken down by market sector and cost basis. It is expected that by 2025/26, a cumulative investment amount of $732.2 million dollars will have been spent on Power Smart electric programs.

Electric Power Smart Utility Budget
2011/12 - 2025/26
(Millions, 2011 $)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Residential	4.6	5.2	4.9	2.7	1.7	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer Service Initiatives	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial	12.5	10.7	9.8	9.4	8.7	8.9	8.9	8.5	6.2	6.1	6.0	5.9	5.9	6.7	1.9
Industrial	2.7	3.5	4.3	5.2	6.0	4.3	3.7	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.7
Rate/Load Management	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Customer Self-Generation	2.5	4.2	4.3	3.2	4.3	2.7	0.6	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0
Support and Codes & Standards	4.1	3.9	3.9	3.9	3.9	3.9	3.7	3.7	3.7	3.6	3.6	3.6	3.6	3.6	3.6
Contingency	0.0	1.0	1.5	1.5	1.5	1.5	1.5	1.5	1.5	2.0	2.0	2.0	2.0	2.0	2.0
Annual Costs	32.5	34.4	34.7	31.8	32.1	28.7	24.5	23.9	21.5	21.3	21.2	21.2	21.1	21.9	17.1
Cumulative Cost, 2011 - 2025	$32.5	$66.9	$101.6	$133.4	$165.5	$194.2	$218.7	$242.6	$264.1	$285.4	$306.5	$327.7	$348.8	$370.7	$387.8
Cumulative Cost, 1989 - 2025	$376.9	$411.3	$446.0	$477.8	$509.9	$538.6	$563.0	$586.9	$608.4	$629.7	$650.9	$672.1	$693.2	$715.1	$732.2

The following graph provides the cumulative electric DSM utility cost for electric DSM from 1989/90 through to 2025/26. Electric expenditures to date comprise 47% of the projected cumulative electricity expenditures for 2025/26.



2.3 Electric DSM Cost Effectiveness

The following table outlines the cost effectiveness of the electric program offerings provided in the 2011 Power Smart Plan.

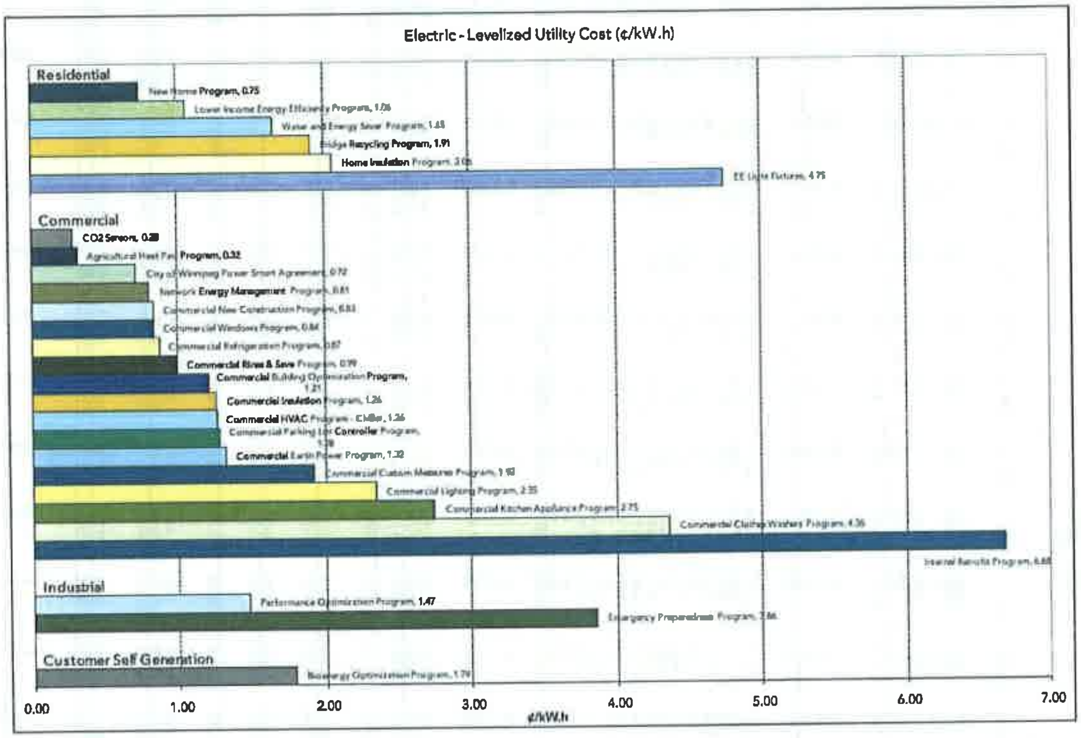
Power Smart Plan Economic Cost Effectiveness Ratios and Levelized Costs
2011/12 - 2038/39

	RIM	LUC (¢/kW.h)	Customer Payback (years)
Residential			
New Home Program	1.5	0.7	8.4 * c
Home Insulation Program	1.5	2.1	2.7 *
Water and Energy Saver Program	1.0	1.6	n/a ^
Lower Income Energy Efficiency Program ** >	1.5	1.1	10.6
EE Light Fixtures	0.7	4.7	n/a ^
Fridge Recycling Program	0.8	1.9	2.7
Residential Programs Total	1.3	1.5	2.0
Commercial			
Commercial Lighting Program	1.2	2.4	4.2 *
Commercial Custom Measures Program	1.3	1.9	9.5
Commercial Windows Program	1.6	0.8	0.4
Commercial HVAC Program - Chiller	1.0	1.3	12.6
City of Winnipeg Power Smart Agreement	1.5	0.7	0.0
Commercial Refrigeration Program	1.2	0.9	1.7
Commercial Insulation Program	1.7	1.3	1.8
Commercial Earth Power Program	1.5	1.3	7.5 *
Commercial New Construction Program	1.4	0.8	3.1 c
Commercial Building Optimization Program	1.6	1.2	1.1
Internal Retrofit Program	1.3	6.7	n/a ^
Commercial Kitchen Appliance Program	1.2	2.8	0.0 c
Commercial Clothes Washers Program	1.4	4.4	4.9 *
Network Energy Management Program	1.3	0.8	1.2 *
CO2 Sensors	2.0	0.3	1.4 *
Commercial Programs Total	1.3	1.9	3.5
Commercial Market Effects			
Agricultural Heat Pad Program	1.6	0.3	n/a * ^
Commercial Parking Lot Controller Program	1.1	1.3	1.6 *
Commercial Rinse & Save Program	1.1	1.0	n/a * ^
Commercial Market Effects Total	1.3	1.0	1.6
Industrial			
Performance Optimization Program	1.3	1.5	3.2 *
Emergency Preparedness Program	1.1	3.9	3.2 ^
Industrial Programs Total	1.2	1.9	3.2
Energy Efficiency - Subtotal	1.3	1.8	3.0
Load Management			
Curtailable Rate Program	1.0	n/a	n/a
Customer Self-Generation			
Bioenergy Optimization Program	1.3	1.8	1.0
Overall Portfolio Ratio	1.2	2.4	2.3

Notes:
* Program assumption includes Spillover, future Market Transformation and/or Participant Re-Investment
** Excludes all Affordable Energy Fund Expenditures. Including AEF costs, LIEEP's RIM is 1.2 and LUC is 3.5 ¢/kW.h
c Program assumption includes savings from Codes & Standards
^ Program with nil or negative net customer costs
1) Overall RIM includes Curtailable Rates Program / Overall LUC and Customer Payback does not include Curtailable Rates Program
2) Overall benefit/cost ratios & utility cost do not include Curtailable Rates Program
3) Overall portfolio ratios include support and contingency costs
4) Overall portfolio ratios do not include Affordable Energy Fund Expenditures
5) Customer Payback tests include first year water savings benefits

For electricity, the overall Rate Impact Measure (RIM) benefit/cost ratio is 1.2. The overall levelized utility cost for electric programs including support and contingency costs is 2.4 cents per kilowatt-hour.

The following chart compares the Levelized Utility Cost of the electric program offerings provided in the 2011 Power Smart Plan.



APPENDIX A 5

Annual Program Budgets (Utility Costs)
2011 PS Plan
(000's in 2011 $)

		2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	Cumulative Total	
RESIDENTIAL																		
Incentive Based																		
New Home Program		$371	$512	$549	$568	$588	$343	$10	$10	$10	$10	$0	$0	$0	$0	$0	$2,971	
Home Insulation Program		$1,242	$1,143	$1,052	$966	$884	$805	$120	$0	$0	$0	$0	$0	$0	$0	$0	$6,212	
Water and Energy Saver Program		$883	$876	$794	$812	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,365	
Lower Income Energy Efficiency Program		$397	$397	$386	$299	$246	$239	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,965	
EE Light Fixtures		$327	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$327	
Fridge Recycling Program		$1,374	$2,231	$2,144	$39	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,788	
Subtotal		$4,594	$5,158	$4,925	$2,685	$1,718	$1,387	$130	$10	$10	$10	$0	$0	$0	$0	$0	$20,628	7%
Customer Service Initiatives																		
Power Smart Residential Loan Program		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
ecoEnergy		$94	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$94	
Residential Earth Power Program		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal		$94	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$94	0%
COMMERCIAL																		
Commercial Lighting Program		$7,085	$5,639	$5,086	$4,972	$4,806	$4,650	$4,517	$4,385	$4,265	$4,146	$4,027	$3,925	$3,826	$4,549	$102	$65,980	
Commercial Custom Measures Program		$155	$155	$168	$168	$168	$168	$168	$168	$168	$168	$181	$181	$181	$181	$161	$2,562	
Commercial Windows Program		$342	$342	$342	$313	$313	$313	$282	$282	$282	$251	$251	$251	$251	$251	$251	$4,316	
Commercial HVAC Program - Chiller		$159	$143	$146	$150	$155	$165	$170	$0	$0	$0	$0	$0	$0	$0	$0	$1,089	
City of Winnipeg Power Smart Agreement		$38	$38	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$76	
Commercial Refrigeration Program		$189	$201	$208	$220	$226	$239	$251	$260	$276	$288	$307	$325	$350	$378	$0	$3,718	
Commercial Insulation Program		$718	$718	$718	$688	$688	$688	$658	$658	$658	$658	$658	$658	$658	$658	$658	$10,140	
Commercial Earth Power Program		$233	$244	$256	$268	$272	$284	$315	$337	$350	$372	$377	$408	$432	$437	$452	$5,036	
Commercial New Construction Program		$797	$1,144	$1,056	$1,326	$1,641	$1,956	$2,091	$2,271	$0	$0	$0	$0	$0	$0	$0	$12,281	
Commercial Building Optimization Program		$107	$134	$140	$140	$154	$188	$174	$160	$160	$174	$174	$187	$200	$200	$196	$2,487	
Internal Retrofit Program		$1,757	$1,481	$1,181	$881	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,302	
Commercial Kitchen Appliance Program		$111	$126	$146	$161	$178	$193	$208	$1	$1	$1	$1	$0	$0	$0	$0	$1,126	
Commercial Clothes Washers Program		$65	$68	$71	$74	$77	$81	$2	$2	$2	$2	$2	$2	$2	$2	$0	$454	
Network Energy Management Program		$213	$240	$266	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$788	
CO2 Sensors		$5	$5	$5	$5	$5	$5	$6	$6	$0	$0	$0	$0	$0	$0	$0	$42	
Subtotal		$11,974	$10,679	$9,789	$9,373	$8,690	$8,935	$8,848	$8,536	$6,168	$6,066	$5,983	$5,944	$5,905	$6,662	$1,845	$115,296	38%
Market Effects																		
Agricultural Heat Pad Program		$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$78	
Commercial Parking Lot Controller Program		$535	$4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$539	
Commercial Rinse & Save Program		$1	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2	
Subtotal		$541	$10	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$5	$618	0%
INDUSTRIAL																		
Performance Optimization Program		$2,736	$2,736	$2,736	$2,736	$2,736	$2,736	$2,736	$2,736	$2,736	$2,736	$2,736	$2,736	$2,736	$2,736	$2,736	$41,041	
Emergency Preparedness Program		$0	$727	$1,532	$2,465	$3,252	$1,581	$995	$821	$834	$848	$861	$874	$888	$901	$914	$17,491	
Subtotal		$2,736	$3,463	$4,268	$5,201	$5,988	$4,317	$3,731	$3,557	$3,570	$3,584	$3,597	$3,610	$3,624	$3,637	$3,650	$58,532	19%
CONSERVATION SUBTOTAL		$19,939	$19,310	$18,987	$17,264	$16,401	$14,644	$12,715	$12,108	$9,754	$9,665	$9,585	$9,559	$9,533	$10,304	$5,500	$195,268	63%
LOAD MANAGEMENT																		
Curtailable Rate Program		$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$89,281	
LOAD MANAGEMENT SUBTOTAL		$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$5,952	$89,281	29%
CUSTOMER SELF-GENERATION																		
BioEnergy Optimization Program		$2,540	$4,215	$4,342	$3,163	$4,295	$2,711	$567	$571	$575	$0	$0	$0	$0	$0	$0	$22,979	
CUSTOMER SELF-GENERATION SUBTOTAL		$2,540	$4,215	$4,342	$3,163	$4,295	$2,711	$567	$571	$575	$0	$0	$0	$0	$0	$0	$22,979	7%
Subtotal of Programs		$28,431	$29,477	$29,281	$26,379	$26,648	$23,308	$19,234	$18,631	$16,281	$15,617	$15,537	$15,511	$15,485	$16,256	$11,453	$307,528	100%
Incremental Support Activity		$1,051	$891	$891	$891	$891	$891	$891	$891	$891	$891	$891	$891	$891	$891	$891	$13,526	
Contingency		$0	$1,000	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$23,500	
Utility Costs (2011 to 2025)		$29,482	$31,368	$31,672	$28,770	$29,039	$25,699	$21,625	$21,023	$18,672	$18,508	$18,428	$18,402	$18,377	$19,147	$14,344	$344,554	
Customer Service and Standards Support		$3,046	$3,041	$3,040	$3,022	$3,013	$3,012	$2,856	$2,856	$2,855	$2,758	$2,757	$2,757	$2,757	$2,757	$2,755	$43,282	
Total Utility Costs (2011 to 2025)		$32,528	$34,409	$34,712	$31,792	$32,051	$28,711	$24,482	$23,879	$21,527	$21,266	$21,186	$21,159	$21,133	$21,904	$17,098	$387,837	
Committed To Date																		
Activity cumulative to 2009/10	$312,946	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$312,946	
Current Year Estimate	$31,413	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$31,413	
Total Committed to Date	$344,359	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$344,359	
TOTAL UTILITY COSTS (1989	$344,359	$32,528	$34,409	$34,712	$31,792	$32,051	$28,711	$24,482	$23,879	$21,527	$21,266	$21,186	$21,159	$21,133	$21,904	$17,098	$732,196	

NOTE: May not add up due to rounding

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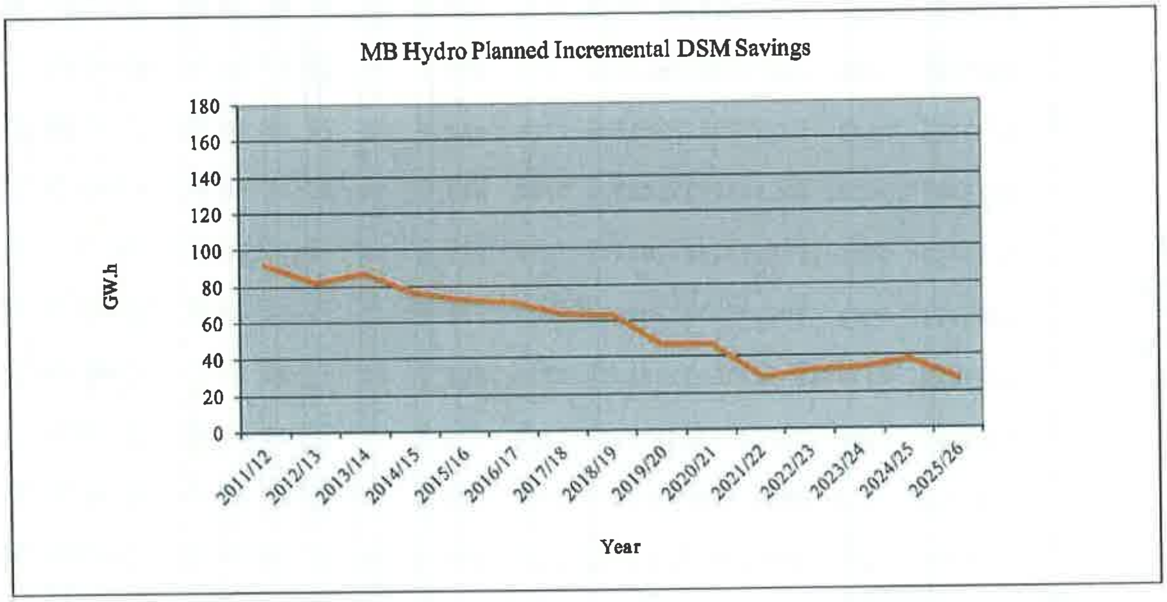
PUB/MH I-107

Reference: Tab 7 Section 2.3 Pages 14

e) **Please update MH's planned DSM savings (2011 GRA- RCM/TREE #6) to reflect the lower MC of energy.**

ANSWER:

Please see the following graph which is based on the information provided in Appendix A.3 of the 2011Power Smart Plan, which was filed as Appendix 7.1 of the Application.



Annual Energy Savings (GW.h)
2011 PS Plan

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26		GW.h at Generation 2025/26
RESIDENTIAL																	
Incentive Based																	
New Home Program	1.0	1.9	3.0	3.8	4.6	10.6	16.2	21.9	27.7	33.5	33.5	33.5	33.5	33.5	33.5		38.1
Home Insulation Program	4.0	7.7	10.9	13.8	16.4	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6		21.3
Water and Energy Saver Program	4.6	9.3	13.6	18.1	18.1	18.1	18.1	18.1	17.7	17.2	17.2	17.2	17.2	17.2	17.2		19.6
Lower Income Energy Efficiency Program	2.8	5.6	8.3	10.5	12.2	13.7	13.7	13.7	13.3	12.8	12.0	11.3	10.7	10.2	10.0		11.4
EE Light Fixtures	0.6	0.6	0.6	0.6	0.6	0.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4		0.5
Fridge Recycling Program	5.9	17.8	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	29.7	24.2	13.2	2.1		2.4
Subtotal	18.9	42.9	66.2	76.6	81.6	91.4	96.9	102.6	107.4	112.3	111.5	110.8	104.6	93.1	81.8	9%	93.2
Customer Service Initiatives																	
Power Smart Residential Loan Program	0.6	1.3	1.9	2.6	3.2	3.8	4.5	5.1	5.8	6.4	7.0	7.7	8.3	9.0	9.6		10.9
ecoEnergy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
Residential Earth Power Program	0.5	1.0	1.7	2.4	3.3	4.3	5.4	6.7	8.1	9.5	11.0	12.6	14.3	16.1	17.9		20.4
Subtotal	1.1	2.3	3.6	5.0	6.5	8.1	9.9	11.8	13.8	15.9	18.1	20.3	22.6	25.0	27.5	3%	31.4
COMMERCIAL																	
Commercial Lighting Program	23.0	40.8	56.6	71.7	85.6	98.7	111.3	122.9	133.8	144.1	144.3	147.9	152.4	160.3	161.7		184.4
Commercial Custom Measures Program	0.6	1.2	1.8	2.5	3.1	3.8	4.5	5.1	5.8	6.5	7.1	7.8	8.4	9.1	9.8		11.1
Commercial Windows Program	3.0	5.9	8.9	11.5	14.1	16.7	18.9	21.1	23.3	25.2	27.0	28.9	30.8	32.7	34.6		39.4
Commercial HVAC Program - Chiller	0.8	1.6	2.3	3.1	3.8	4.6	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4		6.2
City of Winnipeg Power Smart Agreement	0.5	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.5	0.0	0.0		0.0
Commercial Refrigeration Program	1.5	3.2	5.0	7.0	9.0	11.3	13.8	16.1	18.7	21.5	24.5	27.8	31.4	35.4	35.4		40.4
Commercial Insulation Program	3.9	7.8	11.7	15.4	19.1	22.7	26.3	29.8	33.3	36.8	40.2	43.7	47.1	50.5	53.9		61.5
Commercial Earth Power Program	1.4	2.9	4.5	6.2	7.8	9.5	11.5	13.7	15.9	18.4	20.8	23.4	26.2	29.1	32.0		36.4
Commercial New Construction Program	3.9	10.0	21.9	34.9	48.8	63.7	79.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0	95.0		108.3
Commercial Building Optimization Program	0.8	1.9	3.2	4.4	5.7	7.5	9.1	10.5	11.8	13.4	14.2	14.9	16.0	17.1	18.2		20.7
Internal Retrofit Program	14.9	19.0	22.0	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1		27.5
Commercial Kitchen Appliance Program	0.3	0.6	0.9	1.2	1.6	2.0	2.3	2.9	3.5	4.1	4.6	4.6	4.4	4.1	3.7		4.3
Commercial Clothes Washers Program	0.1	0.2	0.4	0.5	0.6	0.6	0.7	0.8	0.9	0.9	1.0	1.0	1.0	0.9	0.8		0.9
Network Energy Management Program	1.3	2.9	4.4	6.1	7.8	9.0	10.4	12.0	13.8	15.7	13.3	10.5	7.6	4.2	0.6		0.7
CO2 Sensors	0.1	0.2	0.3	0.4	0.5	0.7	0.9	1.1	1.2	1.2	1.3	1.3	1.4	1.5	1.6		1.8
Subtotal	56.1	99.1	144.8	189.9	232.7	276.2	319.2	361.5	387.5	413.2	423.9	437.5	451.7	469.4	476.8	53%	543.6
Market Effects																	
Agricultural Heat Pad Program	0.2	0.4	0.6	0.7	0.8	0.9	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.2		1.4
Commercial Parking Lot Controller Program	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6		4.1
Commercial Rinse & Save Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
Subtotal	3.8	4.0	4.2	4.3	4.4	4.5	4.6	4.6	4.7	4.7	4.7	4.8	4.8	4.8	4.8	1%	5.5
INDUSTRIAL																	
Performance Optimization Program	12.9	25.8	38.7	51.6	64.5	77.4	90.3	103.2	116.1	129.0	141.9	154.8	167.7	180.6	193.5		212.9
Emergency Preparedness Program	0.0	1.5	6.0	13.5	24.0	27.8	29.3	30.0	30.8	31.5	32.3	33.0	33.8	34.5	35.3		38.8
Subtotal	12.9	27.3	44.7	65.1	88.5	105.2	119.6	133.2	146.9	160.5	174.2	187.8	201.5	215.1	228.8	26%	251.6
CONSERVATION SUBTOTAL	92.8	175.7	263.5	340.9	413.7	485.4	550.1	613.8	660.3	706.7	732.3	761.2	785.2	807.4	819.7	92%	925.3
LOAD MANAGEMENT																	
Curtailable Rate Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
LOAD MANAGEMENT SUBTOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0%	0.0
CUSTOMER SELF-GENERATION																	
BioEnergy Optimization Program	70.8	85.4	102.1	111.0	127.3	133.3	69.2	72.2	75.2	75.2	75.2	75.2	75.2	75.2	75.2		82.7
CUSTOMER SELF-GENERATION SUBTOTAL	70.8	85.4	102.1	111.0	127.3	133.3	69.2	72.2	75.2	75.2	75.2	75.2	75.2	75.2	75.2	8%	82.7
Program Impacts (at meter)	164	261	366	452	541	619	619	686	736	782	808	836	860	883	895	100%	
Program Impacts (at generation)	183	293	411	508	608	696	699	774	830	882	911	943	970	995	1,008		1,008.0
Codes, Standards & Regulations (at meter)	50	104	158	237	317	404	517	559	600	641	681	719	755	790	821		
Codes, Standards & Regulations (at generation)	57	119	180	271	361	460	589	637	684	731	777	820	861	901	926		
POWER SMART 2011 to 2025 Impacts (at meter)	214	365	523	689	858	1,022	1,136	1,245	1,336	1,423	1,489	1,556	1,616	1,673	1,716		
POWER SMART 2011 to 2025 Impacts (at generation)	240	412	591	779	969	1,156	1,287	1,411	1,514	1,613	1,687	1,763	1,831	1,895	1,944		
POWER SMART SAVINGS TO DATE																	
Incentive Based Program Impacts (at meter)	922	915	893	856	857	853	849	833	837	828	826	791	769	744	651		
Incentive Based Program Impacts (at generation)	1,038	1,029	1,004	962	964	959	954	936	935	930	928	889	865	837	733		
Customer Service Initiatives Program Impacts (at meter)	20	20	20	20	20	20	20	20	20	20	20	20	19	15	15		
Customer Service Initiatives Program Impacts (at generation)	23	23	23	23	23	23	23	23	23	23	23	22	22	17	17		
Discontinued Programs (at meter)	156	155	154	154	153	153	153	153	153	153	153	150	146	142	141		
Discontinued Programs (at generation)	174	175	174	173	173	173	173	173	173	173	173	169	164	159	158		
Impacts of Codes & Standards (at meter)	378	378	378	378	378	378	378	378	378	378	378	378	378	378	378		
Impacts of Codes & Standards (at generation)	430	430	430	430	430	430	430	430	430	430	430	430	430	430	430		
TOTAL GW.h (at meter)	1,690	1,833	1,968	2,097	2,266	2,426	2,536	2,627	2,719	2,802	2,866	2,894	2,928	2,952	2,901		
TOTAL GW.h (at generation)	1,906	2,069	2,221	2,367	2,558	2,740	2,867	2,972	3,074	3,168	3,241	3,274	3,312	3,339	3,283		

NOTE: May not add up due to rounding

CAC-GAC/MH II-5

Subject: **Previous DSM Plans forecasts**
Reference: **2011 Power Smart Plan, Appendix 7.1 (Appendix A.3)**

a) **Please provide projected annual energy savings (GWh at meter), both for "Conservation" and for the Overall Plan, for each DSM Plan or Plan Update released from 2000 to 2011. For example:**

CONSERVATION ONLY

	2000	2001	2002	2003	2004	2005	2006	*(Cont'd)* ………	Last yr of plan
2000 Plan	xx	xx	xx	xx	xx	xx	xx	…	xx
2001 Plan		xx	xx	xx	xx	xx	xx	…	xx
2002 Plan			xx	xx	xx	xx	xx	…	xx
2003 Plan				xx	xx	xx	xx	…	xx
(Continued to most recent plan) …………									

ANSWER:

The following tables outline the projected energy savings (GWh at meter).

CONSERVATION ONLY

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
2007 Plan	84	189	276	356	430	495	550	603	654	708	756	-	-	-	-	-	-	-	-
2008 Plan	-	117	223	322	411	496	555	604	654	709	774	814	847	881	915	947	962	-	-
2009 Plan	-	-	150	317	460	544	618	630	640	658	712	766	806	845	885	914	947	954	-
2010 Plan	-	-	-	104	232	333	433	527	601	665	725	762	780	806	838	866	884	898	-
2011 Plan	-	-	-	-	93	176	264	341	414	485	550	614	660	707	732	761	785	807	820

OVERALL PLAN

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
2007 Plan	226	372	500	637	771	907	1,051	1,178	1,303	1,429	1,446	-	-	-	-	-	-	-	-
2008 Plan	-	277	303	448	592	735	844	949	1,045	1,141	1,247	1,328	1,398	1,468	1,537	1,605	1,654	-	-
2009 Plan	-	-	276	496	695	847	990	1,062	1,073	1,146	1,252	1,357	1,444	1,529	1,615	1,688	1,764	1,813	-
2010 Plan	-	-	-	229	414	607	800	999	1,211	1,265	1,378	1,467	1,537	1,611	1,689	1,762	1,824	1,882	-
2011 Plan	-	-	-	-	214	365	523	689	858	1,022	1,136	1,245	1,336	1,423	1,489	1,556	1,616	1,673	1,716

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Written Testimony of Philippe U. Dunsky re. Manitoba Hydro's Demand-Side Management Plan

in the context of Manitoba Hydro's 2012/13 and 2013/14 General Rate Application

on behalf of Consumers Association of Canada (Manitoba) and Green Action Centre

November 15th, 2012

Contents

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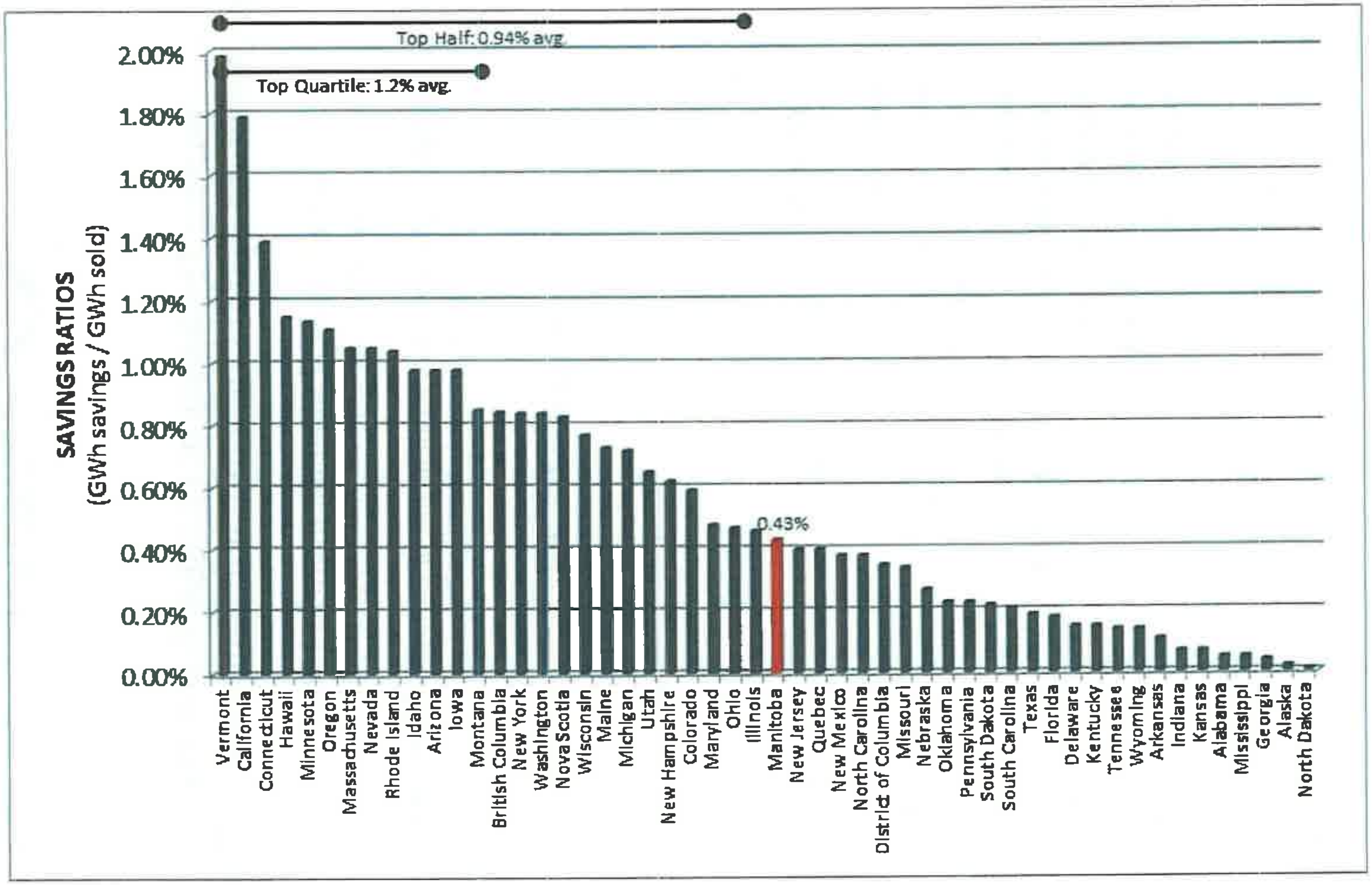
Figure 1. **CURRENT PERFORMANCE – 2010 Savings Ratios across North America**



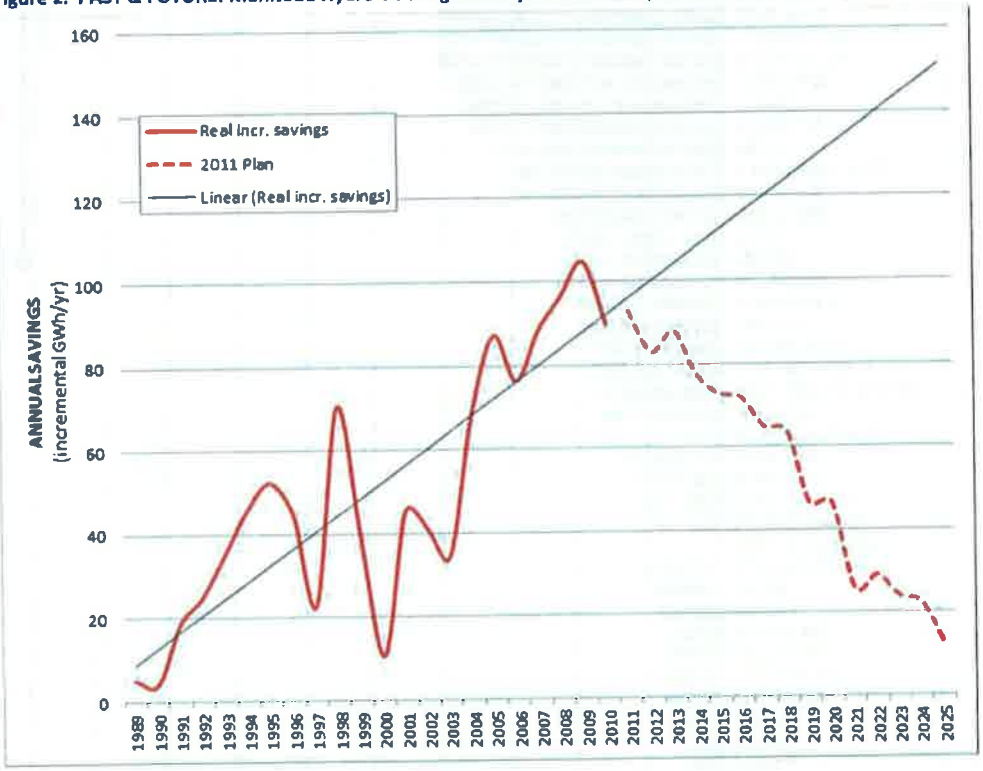
Manitoba Hydro's Planned DSM

We've looked at 2010, but what happens after that?

Over the past two decades, Manitoba Hydro has been growing its Power Smart effort and, as a result, achieving increased energy savings. 2009 marked a DSM high-water year for Hydro.

Looking forward, however, I was surprised to find that Manitoba Hydro is planning on a significant *decrease* in its savings targets. As can be seen in Figure 2, Manitoba Hydro's incremental savings decline steadily starting in 2010.[2] In 2025, annual savings from DSM would fall below 1991's savings, according to the 2011 Plan.

Figure 2. PAST & FUTURE: Manitoba Hydro's Savings History and Outlook (Programs Only)



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[2] These graphs present what can be termed "net annual incremental" savings, meaning that in theory, they account for both new savings in that year, as well as the loss of savings from previous years due to the end of a measure's useful life. While we would have preferred to report on incremental savings only, Manitoba Hydro was not able to provide the requisite information. I would expect the impact to be negligible for the 2015 horizon, and marginal for 2020, given that Manitoba Hydro's net savings analysis was reset in 2011, and that most measures have average lives that extend beyond 10 years (average plan-wide EULs are typically in the range of 15 years). However, it is worth noting that as they near 2025, Manitoba Hydro's reported incremental savings may be somewhat deflated due to the end of previous savings' lives.

Figure 4. 2010 Savings Ratios across North America (with 2015, 2020 and 2025 MH planned savings for illustrative purposes)

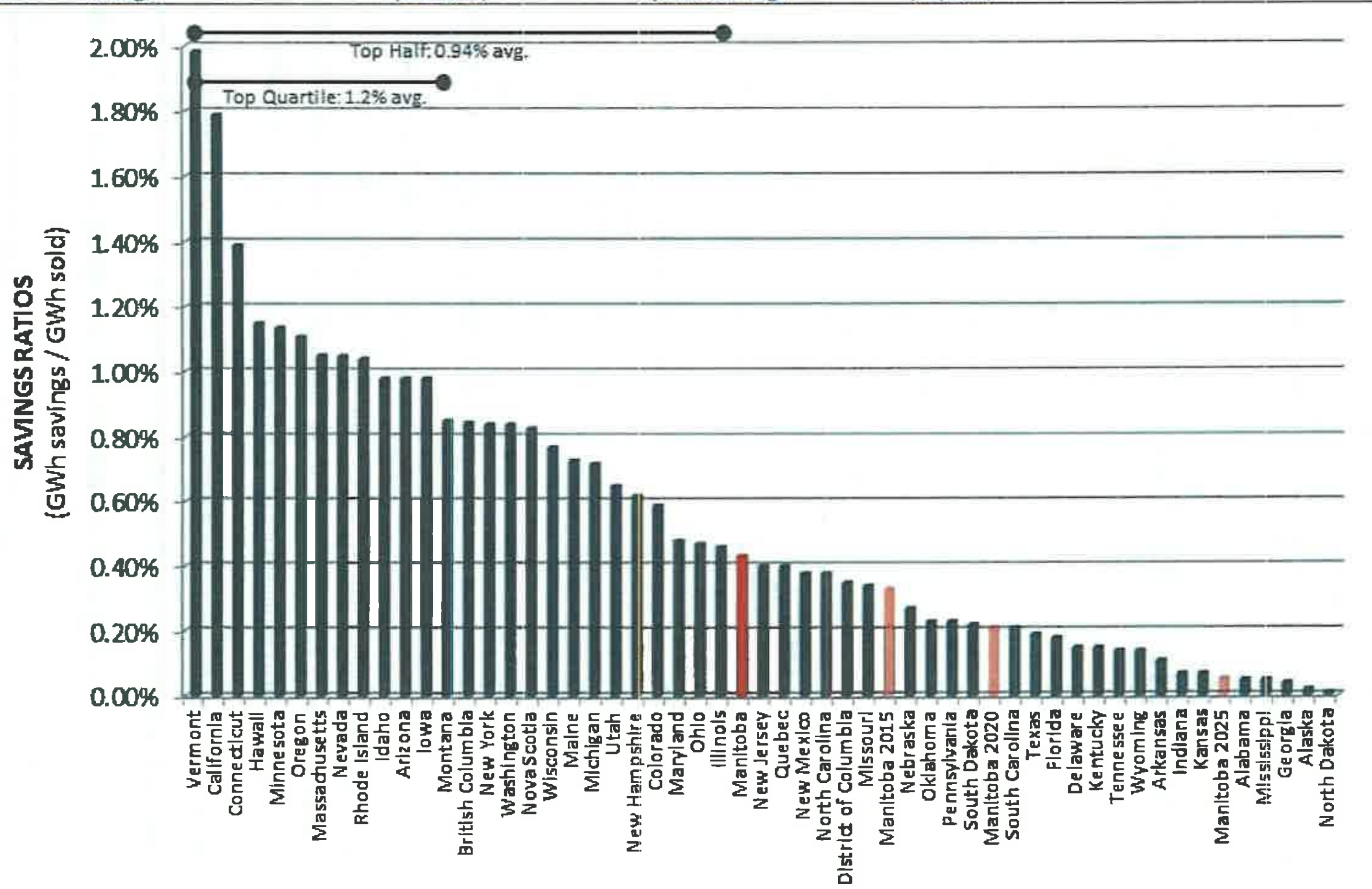

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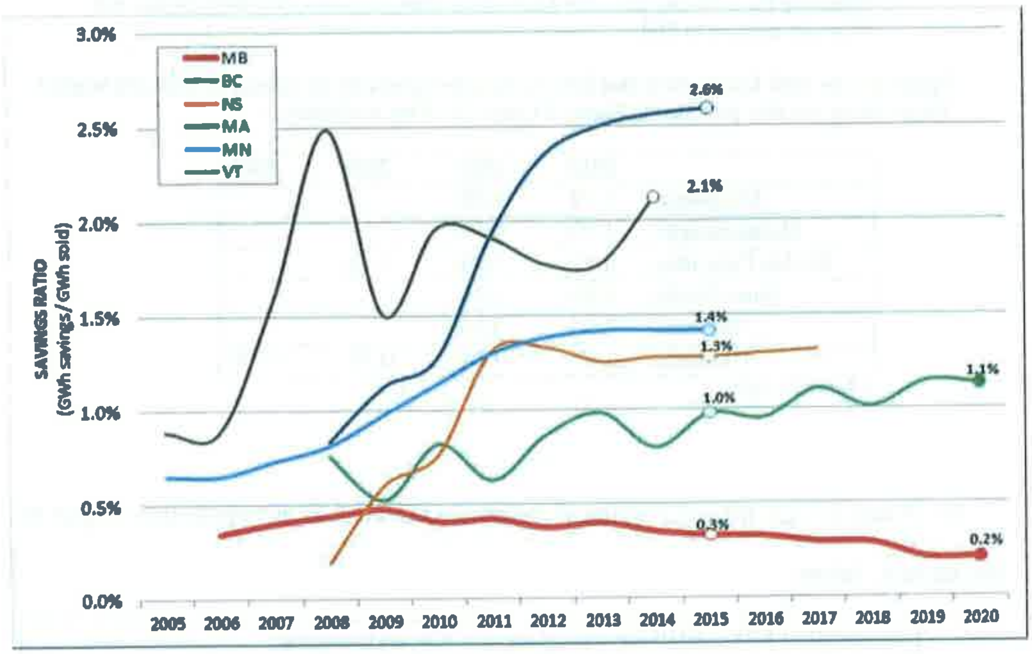
Figure 5. FUTURE: Planned Savings of Manitoba and Five Cohorts (Programs Only)



To put this into context, Manitoba Hydro's 2015 planned savings ratio is less than one-third the equivalent savings planned for in B.C. (less than one-fifth by 2020); is less than a quarter the savings planned for in Nova Scotia and Minnesota; and is below one-seventh those planned for in Massachusetts and Vermont.

PUB/CAC & GAC 4 Reference: Page 10 Figure 4

a) Mr. Dunsky has indicated a continued decline in MH's Saving Ratios, relative to other jurisdictions. Please provide an updated comparison showing the Savings Ratio changes reflecting the evolving plans for Minnesota, Massachusetts, BC, Nova Scotia and Vermont relative to MH.

Please see the table below. Note that four of the cohort plans do not extend to 2020 and beyond. These values are also provided in Figure 5 (page 13) of my testimony.

	2010	2015	2020	2025
Minnesota	1.1%	1.4%		
Massachusetts	1.3%	2.6%		
British Columbia	0.8%	1.0%	1.1%	
Nova Scotia	0.8%	1.3%		
Vermont	2.0%	2.1%*		
Manitoba	0.4%	0.3%	0.2%	0.1%

** Data is for 2014.*

b) Please provide the composition of generation resources in the jurisdictions in part (a).

See the table below.

Generation Mix – 2010 (sum may not add up to 100% due to rounding)						
	MA	MN	VT	BC	NS[a]	MB
Natural gas	60%	8%	0%	4%	20%	0%
Coal	19%	52%	0%	0%	57%[b]	0%
Nuclear	14%	25%	72%	0%	0%	0%
Wind	0%	9%	0%	1%	7%	1%
Biomass	3%	3%	7%	3%	0%	0%
Hydroelectric	2%	2%	20%	61%	10%[c]	98%
Others	2%	1%	0%	32%[d]	6%	1%

[a] 2011 data. [b] Includes petcoke. [c] Includes tidal. [d] primarily short-term purchases from hydro installations.

As the reader will note, every region's generation mix is different. We are not aware of any relationship between generation mix and energy efficiency.

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PUB/MH I-107

Reference: Tab 7 Section 2.3 Pages 14

a) **Please indicate the marginal cost and its derivation that MH is currently using to evaluate new and existing DSM initiatives**

ANSWER:

The levelized marginal value used for the analysis in the 2011 Power Smart Plan is 8.52 cents per kW.h (at meter). The marginal cost contains the expected value of electricity exports which is commercially sensitive. Therefore, detailed information on the derivation of the marginal cost cannot be provided.

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PUB/MH I-107

Reference: Tab 7 Section 2.3 Pages 14

b) Please update section 2.3 table on page 14. RIM calculations using current marginal cost (Appendix 10.7 pages 9 & 10) and explain how MH re-evaluates the past DSM initiatives to reflect the post 20098/09 drop in the average price of export prices.

ANSWER:

Manitoba Hydro does not undertake multiple calculations using various marginal costs values either for evaluation or planning purposes. The information requested would require substantive effort to complete.

To address changes occurring within the market on a go forward basis, Manitoba Hydro revisits its DSM plan on an annual basis and adjusts its DSM offerings and strategies to respond to these changes. As part of this exercise, revised metrics including RIM's are calculated.

The table in section 2.3 includes the marginal costs that were in place at the time the 2011 Power Smart Plan was developed, which would reflect the influence of the 2008 economic downturn on export prices known at that time.

PUB/MH I-107

Reference: Tab 7 Section 2.3 Pages 14

c) Please explain the logical basis for future DSM initiatives when export revenue rates fall below:

i. Residential energy rates
ii. New incremental hydraulic generation costs
iii. Wind energy purchases.

ANSWER:

In addition to value derived over the long term from the export market, the marginal values used to assess DSM initiatives also include components reflecting the avoided cost of new transmission and distribution infrastructure. If incremental export revenues were to decline to a level where they no longer offered an offsetting value, then the marginal benefits of DSM would then shift from the value of export market to a valuation of the benefit of deferring new generation facilities recognizing that there is an economic benefit to achieving load savings in the province.

Manitoba Hydro revisits its DSM plan on an annual basis utilizing the latest marginal values and domestic rate forecasts. Each DSM program is assessed using the latest market information and these updated values to determine the appropriate level of investment in the DSM program. This flexibility of DSM allows Manitoba Hydro to increase or decrease its intensity in programs in response to economic conditions and to continue to pursue all cost-effective DSM.

Appendix F - Program Evaluation Criteria

Manitoba Hydro's Power Smart programs take into account the underlying differences in the electricity and natural gas industries and the nature of the programs evaluated. Power Smart programs are assessed annually to ensure the individual programs as well as the overall portfolio of programs are cost-effective and meeting intended market transformation objectives and targets.

Nature of Electricity and Natural Gas Markets

The nature of the electricity and natural gas markets are similar, however unique differences exist and need to be considered in Manitoba Hydro's Power Smart initiative.

For electricity, lower consumption in Manitoba and lower utility revenue is offset by higher revenues realized by selling the conserved energy in the export market. Lower electricity consumption also defers the need to invest in new transmission facilities that would be required to meet future domestic demand. Load management and certain types of demand response initiatives are also unique elements of electricity markets (e.g. short term price volatility creates opportunities for cost-effective load management and demand response initiatives). The combined effect results in an economic case for Manitoba Hydro to aggressively pursue electricity DSM in Manitoba.

With natural gas, lower consumption in Manitoba is offset by lower natural gas purchases from Alberta. In general, this is a one-to-one relationship as Manitoba Hydro passes the cost of primary natural gas and transportation through to its customers with no mark up on the commodity. Load management opportunities are generally not available in the natural gas market as these operational issues are handled through natural gas storage facilities.

Program Categories

a) Customer Service Programs

Customer service programs are those programs offered as part of the overall Power Smart initiative that represent the customer service levels that would be expected of a utility. Customer service programs and services are assessed by the aggregate value realized by both the Corporation's customers and the Corporation. These assessments are undertaken on an on going basis and require a qualitative evaluation of the benefits. Service levels are then adjusted accordingly.

b) Cost-Recovery Programs

Cost-recovery programs are those programs where the cost associated with the program is recovered from participating customers through fees or charges (e.g. interest rates). The cost-effectiveness of these programs is assessed annually with fees or charges adjusted accordingly.

c) Financial Loan Programs

Financial Loan Programs assists participating customers in the installation and/or upgrade of energy efficient measures by offering low interest financing opportunities.

e) Incentive Based Programs

Incentive based programs are those programs where Power Smart uses a financial incentive to encourage customer participation. Assessments provide feedback on the success and cost-effectiveness of individual programs and the Power Smart portfolio. The results of these assessments drive program design and strategy modifications.

f) Energy Efficient Codes & Standards

In many markets, the most effective and permanent form of market transformation for energy efficient technologies and practices is the adoption of energy efficient codes and standards as it ensures that customers do not revert to less efficient technologies/practices once the incentives and/or promotional activities are discontinued. Consequently, the process of achieving these changes is complex and lengthy as it involves many stakeholders, varying environmental and market conditions and market acceptance.

Manitoba Hydro's strategy to affect change in codes and standards involves being an aggressive and active participant and in many cases, a driving force on a number of provincial and national energy efficiency codes and standards committees (e.g. Manitoba Hydro representatives often chair committees). The focus of Manitoba Hydro's efforts on these committees is towards developing new energy efficient technologies, developing energy efficient codes and standards and facilitating market acceptance of new technologies and building design practices.

Economic Effectiveness Ratios

Manitoba Hydro uses a number of cost effective tests to assess energy efficient opportunities, including whether to pursue an opportunity, how aggressively an opportunity will be pursued, effectiveness of program design options and the relative investment from ratepayers and participants. In addition to quantitative assessments, Manitoba Hydro also considers various qualitative factors including equity (i.e. reasonable participation by various ratepayer sectors such as lower income) and overall contribution towards having a balanced energy conservation strategy and plan.

Quantitative assessments include using the following cost effective tests:

- Marginal Resource Cost (MRC) test;
- Total Resource Cost (TRC) test;
- Societal Cost Test (SC) test;
- Rate Impact Cost (RIM) test;
- Levelized Utility Cost (LUC); and
- Simple Customer Payback calculation.

a) Marginal Resource Cost Test

The Marginal Resource Cost (MRC) test is used as a preliminary and high level screen to assess the benefits associated with an energy efficient opportunity. This benefit/cost ratio is a simple assessment to determine whether the benefits that are associated with an energy efficient opportunity are greater than the costs. This assessment is undertaken irrespective of who realizes the benefits and who pays the costs. In addition, the assessment excludes any program administration costs (e.g. program planning, design, marketing, implementation and evaluation).

In general, if an opportunity offers greater benefits relative to costs, then a program for pursuing the opportunity should be considered, however Manitoba Hydro will also consider supporting certain programs where the benefits are less than the costs. In the latter case, the rationale driving the support will be driven by other qualitative factors such as supporting emerging technologies (e.g. solar panels). The Marginal Resource Cost test is defined as follows:

$$\text{MRC} = \frac{\textbf{PV (Marginal Benefits)}}{\textbf{PV (Incremental Product Costs)}}$$

Where:

- For electricity, the Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market, the avoided cost of new infrastructure (e.g. electric transmission facilities) and measurable non-energy benefits (e.g. water savings);

- For natural gas, the Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas, avoided transportation costs, the value of reduced greenhouse gas emissions (GHGs) and measurable non-energy benefits (e.g. water savings);

- Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.

b) Total Resource Cost Test

The Total Resource Cost (TRC) test is a detailed assessment to determine whether the benefits that are associated with an energy efficiency program are greater than the costs. This assessment is undertaken irrespective of who realizes the benefits and who pays the costs with any economic transfers between the Corporation and the participating customer being excluded.

In general, if program offers greater benefits relative to costs, then a program for pursuing the opportunity should be considered, however Manitoba Hydro will also consider supporting certain programs where the benefits are less than the costs. In the latter case, the rationale driving the support will be driven by other qualitative factors such as supporting emerging technologies (e.g. solar panels) or targeting low participation market sectors (e.g. lower income). The Total Resource Cost test is defined as follows:

$$\text{TRC} = \frac{\textbf{PV (Marginal Benefits)}}{\textbf{PV (Total Program Admin Costs + Incremental Product Costs)}}$$

Where:

- For electricity, the Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market, the avoided cost of new infrastructure (e.g. electric transmission facilities) and measurable non-energy benefits (e.g. water savings);
- For natural gas, the Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas, avoided transportation costs, the value of reduced greenhouse gas emissions (GHGs) and measurable non-energy benefits (e.g. water savings);
- Total Program Admin Costs includes the administrative costs involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs;
- Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.

c) Societal Cost Test

The Societal Cost Test (SC) measures the net economic benefit as measured by the TRC, plus additional indirect benefits such as:

- Avoided environmental or societal externalities (e.g. reduced health care costs, increase productivity, employment) and
- "Non-priced" benefits enjoyed by participants (improved comfort, improved heath)

$$\text{SC} = \textbf{TRC + Additional Indirect Benefits}$$

d) Rate Impact Measure Test

The Rate Impact Measure (RIM) test is used to provide an indication of the long term impact of an energy efficient program on energy rates. The test is a benefit/cost ratio that represents the economic impact of a program from the ratepayer's perspective. All program related savings and costs incurred by the utility, including revenue loss and incentive payments, are taken into account in this assessment. The Rate Impact Measure test is defined as follows:

$$\textbf{RIM} = \frac{\textbf{PV (Utility Marginal Benefits)}}{\textbf{PV (Revenue Loss + Utility Program Admin Costs + Incentives)}}$$

Where:

- For electricity, the Utility Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market and the avoided cost of new infrastructure (e.g. electric transmission facilities);
- For natural gas, the Utility Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas, avoided transportation costs and the value of reduced greenhouse gas emissions (GHGs);
- Revenue Loss includes Manitoba Hydro's lost revenue associated with the participants' reduced energy consumption (i.e. customer energy bill reductions);
- Utility Program Admin Costs includes administrative costs incurred by Manitoba Hydro for staff involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs;
- Incentives include the funds transferred from Manitoba Hydro to the participant associated with implementing the Power Smart measure.

e) Levelized Utility Cost

The Levelized Utility Cost (LUC) is used to provide an economic cost value for the energy saved through an energy efficiency program. The LUC provides the total cost of the conserved energy on a per unit basis levelized over a fixed time period. The cost value allows for a comparison to other supply options and other DSM programs occurring over different timeframes. The Levelized Utility Cost is defined as follows:

$$\textbf{LUC} = \frac{\textbf{PV (Utility Program Admin Costs + Incentives)}}{\textbf{PV (Energy)}}$$

Where:

- Utility Program Admin Costs includes administrative costs incurred by Manitoba Hydro for staff involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs;
- Incentives includes the funds transferred from Manitoba Hydro to the participant associated with implementing the Power Smart measure;
- Energy includes the annual energy savings.

f) Customer Payback Calculation

The Customer Payback calculation provides the simple payback of implementing an energy efficient opportunity for customers. This value outlines the amount of time required before the customer recovers the incremental product cost. The value is useful in determining customer participation rates for energy efficient opportunities. The Customer Payback is defined as follows:

$$\text{Customer Payback} = \frac{\text{Participant Costs - Incentives}}{\text{Annual Bill Reductions}}$$

Where:

- Participant Costs includes the participant's total incremental cost associated with implementing the energy efficient opportunity, which is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.
- Incentives includes funds provided by Manitoba Hydro and external parties to the participant associated with implementing the energy efficient opportunity;
- Annual Bill Reductions include the dollar reductions in the customer's electricity, natural gas, and water bills.

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Other DSM Program Assumptions

Market Transformation
Market transformation is a strategic intervention to achieve a lasting, significant share of energy efficient products and services in targeted markets. Manitoba Hydro's Power Smart strategy focuses on creating a sustainable market change where energy efficient technologies and practices become the market standard.

However, market transformation is difficult to measure. Manitoba Hydro has made significant progress in developing specific methodologies for measuring its impacts. Wherever possible, Manitoba Hydro has attempted to obtain sales/technology specific data to calculate a program's true effect. Difficulties arise in 1) obtaining sales data for areas outside of Manitoba for comparison purposes and in 2) obtaining sales information for Manitoba that fall outside of Power Smart program participation. In some instances, qualitative information is used to determine a program's impact on the market. Manitoba Hydro plans to continue work to further quantify and report on the influence of market transformation within the Manitoba marketplace.

For the 2011 Long Range Plan, the DSM programs that have assumed a future level of market transformation have been noted.

Participant Reinvestment
Participant reinvestment is a marketing assumption which measures the program's influence on a participant's decision to repurchasing the energy efficient technology once the initial product life of the energy efficient technology has ended.

For the 2011 Long Range Plan, the DSM programs that have assumed a future level of participant reinvestment have been noted.

Interactive Effects
Interactive effects are related to the impacts of implementing certain electric efficiency opportunities. As a consequence of implementing a more efficient technology, less heat is often produced. The interactive effect refers to the offsetting need to supplement heat as a result of implementing the energy efficient technology. For example, a CFL emits less heat than a traditional incandescent light bulb; therefore it will take more natural gas to heat the area after the CFL is installed. With the creation of natural gas DSM, electric DSM programs are required to quantify increases in natural gas usage due to interactive effects.

For the 2011 Long Range Plan, electric DSM programs with natural gas interactive effects have been noted.

2010-2011 Power Smart Annual Review

Power Smart Planning, Evaluation & Research Department
Customer Care & Marketing Business Unit

Approved May 1, 2012

Manitoba Hydro
POWER SMART

Exhibit 4.4.1.3 - B
Rate Impact Cost Benefit/Cost Analysis - Electric Incentive-Based Program

	2010/11 Actual	2010/11 Plan^^	Total*	2024/25 Plan^^
			RIM	
RESIDENTIAL				
Home Insulation	1.7	1.7	1.6	1.6
New Home	1.5	1.1	0.8	1.6
Compact Fluorescent Lighting	1.3	1.2	1.2	1.3
Lower Income Energy Efficiency**	1.2	0.8	0.7	1.3
Water & Energy Saver	1.1	1.0	1.1	1.0
Energy Efficient Light Fixtures	1.0	0.8	0.9	0.8
Refrigerator Recycling	-	-	-	0.8
	1.4	1.2	1.2	1.3
COMMERCIAL				
Commercial Earth Power	2.0	1.8	1.7	1.9
Internal Retrofit	1.8	1.3	2.5	1.0
Commercial Custom Measures	1.7	1.3	1.3	1.3
Commercial Building Envelope	1.7	1.9	1.6	1.9
Commercial Building Optimization	1.4	1.5	0.5	1.7
Commercial Refrigeration	1.4	1.2	1.4	1.2
City of Winnipeg Agreement Power Smart AgreementØ	1.3	1.5	0.7	1.6
Commercial Kitchen Appliances	1.1	1.1	1.0	1.3
Commercial Lighting	1.1	1.3	1.1	1.4
Commercial HVAC	1.0	0.9	1.0	1.0
Commercial Clothes Washers	0.9	1.3	1.1	1.5
Power Smart Shops	0.9	0.9	0.7	0.9
Commercial Network Energy Management	0.3	0.8	0.2	1.0
Commercial New Buildings	-	1.4	-	1.5
Power Smart Energy Manager	-	-	-	1.0
	1.3	1.4	1.2	1.4
INDUSTRIAL				
Performance Optimization	1.5	1.2	1.3	1.2
Emergency Preparedness	-	-	-	1.2
	1.5	1.2	1.3	1.2
DISCONTINUED/COMPLETED PROGRAMS	1.5	1.3	0.9	1.3
CUSTOMER SELF-GENERATION PROGRAMS				
Bioenergy Optimization	1.5	1.0	1.3	1.4
OVERALL PROGRAM COSTS	1.4	1.2	1.2	1.2
OVERALL PROGRAM COSTS + SUPPORT COSTS^	1.3	1.2	1.1	1.2

* "Total" values represent the results of the program/portfolio since its inception.
** Includes all Affordable Energy Fund expenditures.
^ Support costs contain customer service initiatives, basic information services and program support costs.
^^ Plan estimates are from the 2010 Power Smart Plan.
Ø Includes the present value of projected future commitment payment receipts.
Note: Benefit/Cost analysis is not calculated for rate/load management programs.

Exhibit 4.4.1.4 - B

Average Levelized Utility Cost at Generation - ¢/kW.h saved by Power Smart Program

	2010/11 Actual	2010/11 Total***	2024/25 Plan^^
		¢/kW.h	
RESIDENTIAL			
Lower Income Energy Efficiency*	2.3	6.3	1.3
Energy Efficient Light Fixtures	1.9	3.6	4.6
New Home	1.6	7.2	0.1
Home Insulation	1.5	2.3	1.9
Compact Fluorescent Lighting	0.9	1.4	1.0
Water & Energy Saver	0.7	1.0	1.8
Refrigerator Recycling	-	-	2.3
Discontinued/Completed Programs	-	0.7	1.0
	1.3	1.4	1.4
COMMERCIAL			
Commercial Network Energy Management	11.9	19.2	1.0
Commercial Clothes Washers	11.2	7.9	4.0
Internal Retrofit	4.2	2.3	8.5
Power Smart Shops	3.7	7.5	3.3
Commercial Kitchen Appliances	2.7	3.5	2.2
Commercial Lighting	2.4	1.4	1.9
City of Winnipeg Agreement Power Smart Agreement	2.3	8.1	0.0
Commercial Building Optimization	1.6	5.4	1.4
Commercial Building Envelope	1.7	2.2	1.2
Commercial Refrigeration	1.3	1.6	1.2
Commercial Custom Measures	1.1	0.8	2.4
Commercial HVAC	1.0	1.4	0.9
Commercial Earth Power	0.9	1.2	1.4
Commercial New Buildings**	n/a	n/a	0.9
Power Smart Energy Manager**	n/a	n/a	2.7
Discontinued/Completed Programs	0.9	0.8	0.4
	2.1	1.5	2.0
INDUSTRIAL			
Performance Optimization	0.8	0.4	1.9
Emergency Preparedness	-	-	4.7
Discontinued/Completed Programs	-	1.1	-
	0.9	0.6	2.5
CUSTOMER SELF-GENERATION PROGRAMS			
Bioenergy Optimization	1.7	1.6	1.9
OVERALL: PROGRAM COSTS	1.6	1.1	2.3
OVERALL: PROGRAM COSTS + SUPPORT COSTS^	1.9	1.4	2.5

* Includes all Affordable Energy Fund expenditures.
** Programs in the start-up phase are not evaluated using the average levelized utility costs metric because the results can be misleading.
*** "Total" values represent the results of the program/portfolio since its inception.
^ Support costs contain customer service initiatives, basic information services and program support costs.
^^ Plan estimates are from the 2010 Power Smart Plan.
Note: Average levelized utility cost analysis is not provided for rate/load management programs.

Exhibit 4.4.3 - B

Total Resource Cost Benefit Analysis - Combined Electric & Gas Incentive-Based Program

	2010/11 Actual	2010/11 Plan^^	Total****	2024/25 Plan^^
			TRC	
RESIDENTIAL				
Water & Energy Saver†	11.8	4.6	10.0	5.9
Compact Fluorescent Lighting**	10.1	5.3	4.2	5.6
Energy Efficient Light Fixtures**	3.8	1.6	1.8	1.6
Home Insulation**	3.1	3.3	2.9	3.1
New Home	1.7	1.5	1.1	1.6
Lower Income Energy Efficiency*†	1.0	1.7	0.8	2.5
Refrigerator Recycling	-	1.1	-	1.2
	2.7	2.8	2.4	2.5
COMMERCIAL				
City of Winnipeg Agreement Power Smart Agreement***	16.9	9.6	1.5	10.9
Commercial Building Envelope	4.1	2.4	3.3	2.3
Commercial Refrigeration	4.0	3.5	3.8	4.4
Commercial Kitchen Appliances†	3.8	3.6	4.0	3.5
Commercial HVAC**	3.5	2.9	3.2	3.4
Commercial Earth Power**	3.5	2.8	2.0	2.9
Commercial Lighting	3.2	2.9	2.4	2.8
Commercial Building Optimization	2.1	2.0	0.8	2.8
Power Smart Shops†	2.1	2.9	1.2	3.3
Commercial Custom Measures	2.0	2.0	1.6	2.0
Internal Retrofit	1.8	1.3	2.4	1.0
Commercial Clothes Washers†	1.2	2.1	1.7	2.3
Commercial Network Energy Management	0.4	2.3	0.2	2.7
Commercial New Buildings	-	4.3	-	5.3
Power Smart Energy Manager	-	-	-	1.2
	3.3	2.6	2.4	2.7
INDUSTRIAL				
Performance Optimization	3.1	2.4	3.5	2.5
Natural Gas Optimization	2.2	1.4	2.4	1.4
Emergency Preparedness	-	-	-	2.7
	2.7	1.8	3.3	2.3
DISCONTINUED/COMPLETED PROGRAMS**†	6.0	5.6	2.4	5.3
	6.0	5.6	2.4	
CUSTOMER SELF-GENERATION PROGRAMS				
Bioenergy Optimization	1.4	1.2	1.4	2.0
	1.4	1.2	1.4	2.0
OVERALL: PROGRAM COSTS	2.8	2.5	2.5	2.6
OVERALL: PROGRAM COSTS + SUPPORT COSTS^	2.6	2.3	2.2	2.2

* Includes all Affordable Energy Fund expenditures.
** Includes market transformation.
*** Includes the present value of projected future commitment payment receipts.
**** "Total" values represent the results of the program/portfolio since its inception.
† Includes water savings benefits.
^ Support costs contain customer service initiatives, basic information services and program support costs.
^^ Plan estimates are from the 2010 Power Smart Plan.
Note: Increased or decreased natural gas benefits resulting from electric incentive-based programs have been included in the overall calculation. Benefit/cost analysis is not calculated for rate/load management programs.

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Manitoba Hydro 2013 & 2014 GRA

Information Requests of the Public Utilities Board

November 22, 2012

b) Please indicate the source of the information that supports the claim that there are 13,750 new electrically heated homes built in Manitoba annually.

The correct value should read "approximately 2,750". This is from Manitoba Hydro's response to CAC-GAC/MH II-4(a), in which 13,750 was provided as the value for new housing starts that use electric heat. I failed to notice that this value was not annual but covered the five-year period from 2005-2009.

PUB/CAC & GAC 18 Reference: Dunsky Report Page 38

Please indicate to what extent increased DSM spending could defer the current need for new Generation in MH's current plans.

To answer this question, we examine two scenarios:

In the first scenario, program-related savings are increased such that, when combined with MH's anticipated *other* savings (codes, standards, self-gen), total savings achieve and maintain a 1% savings/sales ratio. This implies that Manitoba Hydro's programs alone achieve a ratio of approximately 0.6% every year on average.

In the second scenario, program savings are increased such that, combined with other savings sources, the total achieves 1.5%/year on average. For comparison purposes, we note that over the next ten years (2012-2021), B.C.'s *average* equivalent total savings ratio is 1.7%.

Under the 1% scenario (0.6% from programs), additional savings of 637 GWh are generated by the time the Keeyask project is supposed to be commissioned (in-service date 2019/20). This allows Manitoba Hydro to defer this project by three years (assuming that exports do not change). The Conawapa project, scheduled to be commissioned in 2024/25, would be deferred by 7 years (to 2031/32). I note that this analysis is based on energy needs; I have not had the time to conduct the analysis of capacity needs needed to confirm these values.

Under the 1.5% scenario, additional savings of 1,385 GWh/yr by 2019/20 would allow for Keeyask to be deferred by 12 years (to 2031/32). I did not calculate the expected in-service date for the Conawapa project under this scenario as this would be too speculative.

On the cost side, the reader will recall (see Fig. 16 of my testimony) that Manitoba Hydro's current savings cost some 28¢/$kWh_{1st\text{-}YR}$ (this is not to be confused with levelized lifetime savings). This is slightly below the costs incurred by BC Hydro, Efficiency Nova Scotia, and Vermont (30¢/kWh). Assuming that Manitoba Hydro's unit costs increase to 30¢/kWh, Manitoba Hydro would have to spend an additional $191 million (cumulative) by 2019/20 for the 1% scenario, or $416 million (cumulative) for the 1.5% scenario. Of course, other DSM options like codes & standards, and rate structures, are a lot cheaper from the utility's point of view, and would decrease the amount of additional spending required.

Manitoba Hydro 2013 & 2014 GRA

Information Requests of the Public Utilities Board

November 22, 2012

	Business as usual	**1% DSM target***	**1.5% DSM target***
Additional savings by 2019/20	---	637 GWh	1,385 GWh
Additional spending by 2019/20	---	$191 M or less	$416 M or less
Keeyask in-service date	2019/20	**2022/23**	**2031/32**
Conawapa in-service date	2024/25	**2031/32**	**?**

** Includes all of Manitoba Hydro's anticipated savings from codes, standards, and self-generation. The implied MH program-related savings ratios are 0.6% and 1.1%/year, the latter being approximately the same as BC Hydro's.*

The incremental cost is annotated with "or less" because the cost provided assumes that the full increase in savings is derived from increased program-related activity. For example, under the *fully-inclusive* 1.5% target, we assume that program savings increase to 1.1%/yr on average (similar to BC Hydro's latest plans), the remainder involving the same level of *non-program* savings (from codes, standards and self-generation) as currently anticipated by MH. Should the non-program portion of savings increase – e.g. from the introduction of rate structure strategies – then the program-related costs would likely be lower to achieve the same overall savings goal.

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PUB/MH I-109

Reference: 2011 Power Smart Plan Page 11 - LIEEP

a) Please provide demographic data on Low income households broken down by dwelling type and ownership [actual numbers and % of total]

ANSWER:

Please see the following table:

LICO-125 Households in Manitoba Manitoba Hydro Residential Energy Use Survey - 2009						
Dwelling Type	**Own**	**% of Total LICO-125**	**Rent**	**% of Total LICO-125**	**Total By Dwelling Type**	**% of Total LICO-125**
Single Detached	67 410	64%	4 292	4%	71 703	68%
Multi-Attached	6 647	6%	3 752	4%	10 399	10%
Apartment Suite	5 221	5%	17 763	17%	22 984	22%
Total by Ownership	79 278	75%	25 808	25%	105 086	100%

PUB/MH I-109

Reference: 2011 Power Smart Plan Page 11 - LIEEP

b) Please provide details by measure on the forecasted spending on Electric LIEEP for the years 2011/12, 2012/13 and 2013/14.

ANSWER:

Please see the following table:

Spending by Measure	Electric Forecast Spending From 2011 Power Smart Plan			
	2011-12	2012-13	2013-14	Total 2011-14
Electric Participation	533	533	513	1578
Power Smart				
Basic Energy Efficiency Items & Draft Proofing	$ 32,000	$ 32,000	$ 32,000	$ 96,000
Insulation - Attic	$ 163,000	$ 163,000	$ 156,000	$ 482,000
Insulation - Basement/Crawl	$ 80,000	$ 80,000	$ 76,000	$ 235,000
Insulation - Wall	$ 11,000	$ 11,000	$ 10,000	$ 31,000
Total Insulation	$ 253,000	$ 253,000	$ 243,000	$ 748,000
Total Incentives	**$ 285,000**	**$ 285,000**	**$ 274,000**	**$ 845,000**
Total Administration	$ 112,000	$ 112,000	$ 112,000	$ 335,000
Total Power Smart	**$ 397,000**	**$ 397,000**	**$ 386,000**	**$ 1,180,000**
Spending by Measure	**Budgeted Costs**			
	2011-12	2012-13	2013-14	Total
AEF				
Basic Energy Efficiency Items & Draft Proofing	$ 5,000	$ 5,000	$ 5,000	$ 14,000
Insulation - Attic	$ 68,000	$ 68,000	$ 66,000	$ 203,000
Insulation - Basement/Crawl	$ 514,000	$ 514,000	$ 499,000	$ 1,528,000
Insulation - Wall	$ 41,000	$ 44,000	$ 40,000	$ 121,000
Total Insulation	$ 624,000	$ 624,000	$ 605,000	$ 1,852,000
Total Incentives	**$ 628,000**	**$ 628,000**	**$ 609,000**	**$ 1,866,000**
Total Administration	$ 68,000	$ 268,000	$ 268,000	$ 803,000
Total AEF	**$ 896,000**	**$ 896,000**	**$ 877,000**	**$ 2,669,000**
Grand Total PS and AEF	**$ 1,293,000**	**$ 1,293,000**	**$ 1,263,000**	**$ 3,849,000**

PUB/MH I-109

Reference: 2011 Power Smart Plan Page 11 - LIEEP

c) **Please provide a comparison of the forecast spending by measure at the last GRA with that currently forecast in (a) and explain any differences.**

ANSWER:

The attached chart provides a comparison of forecast spending between the data provided in PUB/MH I-111b and PUB/MH II-104 in the 2010/11 & 2011/12 GRA and the data in the 2011 Power Smart Plan referred to in PUB/MH I-109(b).

The primary difference in the total forecast spending is due to changes in the forecast participation of electrically heated homes. Under the 2009 Power Smart Plan provided in the last GRA, participation was projected at an average of 883 homes per year. Participation under the 2011 Power Smart Plan is projected to be an average of 526 homes per year which has been revised to reflect actual experience with the program to date.

Forecast spending is also influenced by differences in the estimated average cost per home requiring upgrades. Under the 2009 Power Smart Plan, the investment was projected to be $4,051/home compared to $2,440/home in 2011 Power Smart Plan. The average cost per home was similar between the two Plans at $796 for 2009 compared to $748 in 2011. The Affordable Energy Fund component however was much higher per home in 2009 at $3,255 compared to $1,692 per home in 2011. Based on actual experience, forecast spending for insulation measures is lower.

The forecast spending per home for administration was also higher in the past forecast.

35c

Spending by Measure	Electric Forecast Spending From Last GRA ($000s)			Electric Forecast Spending From 2011 Power Smart Plan ($000s)			
	2009-10	**2010-11**	**Total**	**2011-12**	**2012-13**	**2013-14**	**Total 2011-14**
Electric Participation	**803**	**963**	1766	**533**	**533**	**513**	**1578**
Power Smart							
Basic Energy Efficiency Items & Draft Proofing	$ 14	$ 15	$ 29	$ 32	$ 32	$ 32	$ 96
Insulation - Attic	$ 223	$ 267	$ 490	$ 163	$ 163	$ 15	$ 482
Insulation - Basement/Crawl	$ 100	$ 124	$ 223	$ 80	$ 80	$ 76	$ 235
Insulation - Wall	$ 144	$ 173	$ 316	$ 11	$ 11	$ 10	$ 31
Total Insulation	$ 466	$ 563	$ 1,030	$ 253	$ 253	$ 243	$ 748
Total Incentives	**$ 480**	**$ 577**	$ 1,057	$ 285	$ 285	$ 274	$ 845
Total Administration	**$ 170**	**$ 178**	$ 348	$ 112	$ 112	$ 112	$ 336
Total Power Smart	**$ 651**	**$ 756**	**$ 1,407**	**$ 397**	**$ 397**	**$ 386**	**$ 1,180**
AEF							
Basic Energy Efficiency Items & Draft Proofing	$ 187	$ 209	$ 396	$ 5	$ 5	$ 5	$ 14
Insulation - Attic	$ 154	$ 174	$ 327	$ 68	$ 68	$ 66	$ 203
Insulation - Basement/Crawl	$ 1,323	$ 1,516	$ 2,838	$ 515	$ 515	$ 499	$ 1,528
Insulation - Wall	$ 193	$ 210	$ 403	$ 41	$ 41	$ 40	$ 121
Total Insulation	$ 1,669	$ 1,900	$ 3,568	$ 624	$ 624	$ 605	$ 1,852
Fridges	$ 468	$ 494	$ 962				
Total Incentives	**$ 2,324**	**$ 2,603**	$ 4,926	$ 628	$ 628	$ 609	$ 1,866
Total Administration	**$ 892**	**$ 892**	$ 1,785	$ 268	$ 268	$ 268	$ 803
Total AEF	**$ 3,216**	**$ 3,495**	**$ 6,711**	**$ 896**	**$ 896**	**$ 877**	**$ 2,669**
Grand Total PS and AEF	**$ 3,867**	**$ 4,251**	**$ 8,118**	**$ 1,293**	**$ 1,293**	**$ 1,263**	**$ 3,849**

PUB/MH I-110

Reference: LIEEP , Appendix 11.1 Page 5

Please provide a full description of the efforts currently being undertaken and delivered under the LIEEP on First Nations Communities.

ANSWER:

Manitoba Hydro currently works with First Nation communities to improve the energy efficiency of their homes by providing materials for insulation upgrades as well as basic energy efficiency materials such as caulking, faucet aerators and low flow showerheads. In addition, Manitoba Hydro provides training and funding for labour so that local residents can install the materials, and Manitoba Hydro pays reasonable costs to ship materials to the communities. Manitoba Hydro's First Nation Energy Advisor works directly with each community to determine which homes need upgrades and then, works with the First Nation community to develop a plan for retrofitting the targeted homes.

To date, 597 homes have been upgraded through the First Nations Power Smart Program in 24 different communities as follows:

Fiscal Year	# of Completed Homes
2009-10	29
2010-11	133
2011-12	244
2012-13 (to August 24, 2012)	191
Total Completed to Date	**597**

Plans are in place to upgrade additional First Nation homes over the next 5 years as follows.

Target # of Completed Homes in Each Fiscal Year	
Fiscal Year	**Target # of Completed Homes**
2012 – 13	230
2013 – 14	207
2014 – 15	186
2015 – 16	168
2016 – 17	151

As of August 24th, 2012, Manitoba Hydro's staff has approached all 63 communities, however progress with participating in Manitoba Hydro's Lower Income Program varies with each community.

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PUB/MH I-47

Reference: **Appendix 4.2, 2011 Annual Report, Page 96, Note 21, Appendix 7.1 Page 44, 2011 Power Smart Plan**

a) **Please provide an update on the Affordable Energy Fund (AEF) including the projected use of the funds, by program and a detailed description of the programs.**

ANSWER:

Projects supported through the Affordable Energy Fund include:

- **Low-Income/Community-Based Initiative: $15.1 Million**
  This initiative targets low-income Manitobans, including Aboriginals and seniors. These funds would be incremental to incentives that are available through Manitoba Hydro's Power Smart programs.

- **Geothermal Support Program: $1.6 Million**
  This initiative supports the application of geothermal technology.

- **Community Energy Development: $15.8 Million**

  - ***Energy & Resource Fund - $750 000***
    This fund, managed by the First Peoples Economic Growth Fund, is a joint initiative between the Government of Manitoba and the Assembly of Manitoba Chiefs. The fund was created to maximize First Nations participation in Major Energy and Resource Projects.

  - ***ecoENERGY Program Funding - $4.5 Million***
    This initiative provides funding to support the cost of offering ecoENERGY audits in Manitoba at a reduced cost for customers.

  - ***Power Smart Residential Loan (Additional) - $350 000***
    This initiative provides funding to reduce the interest rate for the Power Smart Residential Loan from a cost-recovery rate to a rate of 3.9%.

- *Electric Bus - $1.2 Million*
  This joint initiative among the Province of Manitoba, Manitoba Hydro, Red River Community College, New Flyer Industries and Mitsubishi Heavy Industries, provides funding to assist in developing a commercially viable all-electric bus design with near-zero emissions for use in urban transit systems.

- *Fort Whyte EcoVillage - $120 000*
  This initiative provides funding to support the research and design of a world-class EcoVillage located at Fort Whyte Alive.

- *Diesel Community Green Pilot Demonstration - $400 000*
  This initiative provides funding to support a pilot demonstration focusing on green technologies in one of four diesel communities.

- *Swan Lake First Nation Wind Farm - $8 Million*
  This initiative provides funding towards a joint project with the Manitoba Government, Manitoba Hydro and Swan Lake First Nation of a proposed community wind initiative.

- *Metis Generation Fund for Resource & Development - $500 000*
  This funding is to be managed by the Métis Economic Development Organization for the purposes outlined in Bill 11.

- **Community Support and Outreach: $750 000**
  This initiative provides support for the participation of First Nation communities in the Lower Income Energy Efficiency Program through dedicated internal resources.

- **Oil and Propane-Heated Residential Homes: $250 000**
  This initiative extends the eligibility of Power Smart programs to include homes currently heated by a source other than electricity and natural gas.

- **Special Projects: $4.0 Million (including accrued fund interest as of August 31, 2012)**

  - *Residential Energy Assessment Service - $545 000*
    This initiative funds the incremental costs associated with delivering Manitoba Hydro's In-home Energy Assessment service under the Federal ecoENERGY Retrofit program to rural and northern Manitobans.

- ***Oil and Propane Furnace Replacement - $150 000***
  This initiative targets the replacement of oil and propane furnaces with either an electric or high efficient natural gas furnace. The program provides a rebate of $245 to participating customers. Low Income customers will be eligible to convert at a cost of $19 per month for five years.

- ***Residential Solar Water Heating Program - $305 000***
  This initiative supports the application of solar domestic hot water pre-heating systems and the development of the local solar industry.

- ***Power Smart Residential Loan - Up to $2.45 Million***
  This initiative provides funding to reduce the interest rate for the Power Smart Residential Loan from the cost recovery rate to a rate of 3.9%.

- ***Oil and Propane-Heated Residential Homes (Additional) - $300 000***
  This initiative provides further funding to extend the eligibility of Power Smart programs to include homes currently heated by a source other than electricity or natural gas.

PUB/MH I-47

Reference: **Appendix 4.2, 2011 Annual Report, Page 96, Note 21, Appendix 7.1 Page 44, 2011 Power Smart Plan**

b) Please provide an updated continuity schedule for the actual and forecast use of the fund including a detail on the actual and anticipated expenditures by program for the years 2011/12,2012/13 and 2013/14. .[there is a large balance unallocated]

ANSWER:

Please see the following table.

Affordable Energy Fund ($millions)

	Actual Expenditures (millions)						Forecasted Expenditures (millions)				
Initiative	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16 - 2020/21	Total
Lower Income Program	0.3	0.2	0.9	1.7	2.7	3.1	3.8	2.5	-	-	15.1
Geothermal Support	0.6	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.2	1.6
Community Energy Development	-	-	-	-	-	-	-	-	-	-	-
ecoENERGYProgram Funding	-	-	-	-	-	2.8	1.7	-	-	-	4.5
Residential Loan - Additional Funding	-	-	-	-	-	-	0.4	-	-	-	0.4
Energy & Resource Fund	-	-	-	0.8	-	-	-	-	-	-	0.8
Manitoba Electric Bus	-	-	-	-	-	0.7	0.2	0.2	0.1	0.1	1.2
FortWhyte EcoVillage	-	-	-	-	-	0.1	-	-	-	-	0.1
Diesel Community Green Pilot Demonstration	-	-	-	-	-	0.0	0.2	0.2	-	-	0.4
Swan Lake First Nation Wind Farm	-	-	-	-	-	-	-	8.0	-	-	8.0
Métis Generation Fund	-	-	-	-	-	-	0.5	-	-	-	0.5
Community Support and Outreach	-	-	0.0	0.1	0.1	0.1	0.2	0.2	-	-	0.8
Oil and Propane Heated Homes	-	0.1	0.1	0.0	0.0	0.0	0.0	-	-	-	0.3
Special Projects											
Residential ecoEnergy Audits	-	0.1	0.2	0.1	0.1	0.0	-	-	-	-	0.5
Oil and Propane Furnace Replacement	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.2
Solar Water Heaters	-	-	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.3
Residential Loan	-	-	-	0.1	0.3	0.4	0.5	0.4	0.4	0.3	2.5
Oil and Propane-Heated Residential Homes - Additional Funding	-	-	-	-	-	0.0	0.1	0.1	0.1	0.1	0.3
ANNUAL EXPENDITURES	0.9	0.6	1.4	3.1	3.5	7.5	7.5	11.6	0.6	0.7	37.4

Note: Zeros indicate a small amount that rounds to zero.

PUB/MH I-47

Reference: **Appendix 4.2, 2011 Annual Report, Page 96, Note 21, Appendix 7.1 Page 44, 2011 Power Smart Plan**

c) **Please provide MH's understanding and role in the recently announced Energy Savings Act and the detailed plans, costs, and implications of this Act on rate-payers.**

ANSWER:

The Act contains provisions regarding the following three elements:

1. Affordable Energy Fund
Under the Act, provisions exist to continue the fund at the discretion of the Corporation, in consultation with the Minister responsible for Manitoba Hydro ("Minister").

2. Energy Efficiency Plan
In consultation with the Minister, Manitoba Hydro is required to prepare an energy efficiency plan by March 31, 2013 and provide updates each subsequent fiscal year. The plan is to set out energy efficiency targets, strategies and programs. In addition, Manitoba Hydro is required to submit to the Minister a report on the achievements of its energy efficiency efforts which will be subsequently tabled in the Assembly.

3. On-Meter Energy Efficiency Improvements Program
Manitoba Hydro may establish an on-meter efficiency improvements program. Under this program, Manitoba Hydro would finance the cost of improving the efficiency of a customer's building and recover the amount through a monthly charge.

Manitoba Hydro is exploring opportunities which may be available through working with community groups to capture more energy efficient opportunities and is also assessing the merits of an On-Meter Energy Efficiency Improvement Program.

The overall implications, including the cost to Manitoba Hydro ratepayers to develop and implement programming measures as may be required under this Act, are not known at this time.

News Releases

DATE: 2012 11 05

PAYS Financing Program Makes Energy Efficiency More Accessible

Manitoba Hydro announced a new financing program today that makes energy efficiency accessible to more Manitoba homeowners or tenants who rent a home.

Using on-bill financing, the Power Smart Pay As You Save (PAYS) Financing Program provides Manitoba Hydro residential customers a convenient option for completing energy efficient upgrades to their homes while keeping upfront costs and future monthly finance payments as small as possible.

To accomplish this, PAYS Financing allows a customer to use their estimated annual utility savings gained from installing energy efficient measures, such as a high-efficiency furnace or attic insulation, to pay for those measures. There is no increase in bill payments because the monthly payment for funds borrowed from Manitoba Hydro must be less than the estimated annual utility bill savings averaged out on a monthly basis.

"Manitoba Hydro's new Pay As You Save program is the first of its kind in Canada. With huge upfront costs gone, more families will be able to make smart, energy efficiency improvements to their homes and save money each month," said Premier Greg Selinger. "Together, we're putting efficiency upgrades to heating, insulation and home water heating within the reach of more families."

The PAYS Financing Program is Manitoba Hydro's response to The Energy Savings Act enacted by the Province of Manitoba in June to encourage energy and water efficiency upgrades of existing homes and buildings.

PAYS Financing is unique compared to other Manitoba Hydro financing options because it is tied to the property, allowing a customer to transfer their financing to the next homeowner or tenant renting their property. (The owner of the property must have a tenant's consent to apply the PAYS monthly payment to their utility bill.)

The program covers upgrades to the following product categories:

- Residential space heating equipment;
- Insulation;
- Residential water heating and conservation, including

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- drain water heat recovery systems,
- toilets (in conjunction with one of the above energy efficient measure).

"Manitoba Hydro has long been a leader in providing financing for energy efficiency on our customer bills," said Scott Thomson, Manitoba Hydro's President and Chief Executive Officer. "Our Power Smart Residential Loan Program has already been recognized as the most successful on-bill finance plan in North America. The new PAYS Financing Program further extends the reach of our financing options and expands the number of customers we can help get the most from their energy."

Customers, working with a contractor who must apply on their behalf, can use the PAYS Online Calculator at www.hydro.mb.ca/PAYS to calculate the amount that can be borrowed from Manitoba Hydro. Simply entering a few details about their home and the cost of the retrofit under consideration will generate the monthly payments and the term of the loan.

To make payments lower, the term of the loan can be extended - up to 25 years depending on the upgrade. If the cost of the upgrade exceeds the amount that can be borrowed, the customer can pay the difference to the contractor upfront if they choose to proceed with the work.

The monthly payment is added to a customer's Manitoba Hydro energy bill. The annual interest rate -currently 3.9 per cent - is fixed for 5 years and the minimum allowable financing amount is $500.

PAYS Financing is not available for unoccupied homes, seasonal homes (cottages), apartment buildings, or new homes under construction.

More information on the PAYS Financing Program.

News Releases

DATE: 2012 11 27

Power Smart Neighbourhood Program Launched

Manitoba Hydro launched its latest Power Smart energy efficiency program today as part of the utility's commitment to continuing to move Manitoba towards a sustainable energy future. The Power Smart Neighbourhood program will see Manitoba Hydro work with community organizations and groups to bring the benefits of energy efficiency and sustainability to residents of lower income neighbourhoods on a block-by-block project basis.

The program was announced in Winnipeg's William Whyte neighbourhood by Premier Greg Selinger. Dave Chomiak, minister responsible for Manitoba Hydro, and Bill Fraser, Chairman of the Manitoba Hydro-electric Board, were also in attendance.

Measures that might be implemented under the program include free in-home energy reviews, improvements to sealing, caulking and weatherstripping, installing pipe wrapping and water efficiency devices, new high-efficiency furnaces and boilers, and performing insulation upgrades. These improvements can substantially reduce energy costs for lower-income Manitobans.

Community organizations will be responsible for management of each project, as well as promoting and coordinating the program within their respective communities. This will include helping residents in the project area fill out application forms, securing and hiring contractors to undertake the work, and reporting progress to Manitoba Hydro.

Manitoba Hydro will provide funding to community groups for coordination and promotion expenses, as well as provide funding to eligible residents for efficiency improvements through two existing programs - the Lower Income Energy Efficiency Program (LIEEP), or the PAYS program. Manitoba Hydro will also provide technical and marketing support to community organizations to market the program to residents within the community.

Although the program is being launched in Winnipeg, community projects are also underway in Brandon.

"As the program gets fully underway, we expect even more communities to come on board and take advantage of the opportunity to improve the energy efficiency of their low-income neighbourhoods on a block-by-block basis," said Scott Thomson President and CEO of Manitoba Hydro.

"Being Power Smart is not only good for the environment, it can help substantially reduce your energy costs. It's a win-win for everyone."

Related Info

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CURTAILABLE RATE PROGRAM

FOR INDIVIDUAL CUSTOMER LOADS

PROPOSED

TERMS AND CONDITIONS

Manitoba Hydro

July 6, 2012

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CURTAILABLE RATE PROGRAM
TERMS AND CONDITIONS

1. DEFINITIONS

The following expressions when used in these Terms and Conditions shall have the following meanings:

a) **"Billing Month"**: the period of time, generally 30 days, in which Energy and/or Demand is consumed and thereafter billed to the Customer.

b) **"Contingency"**: the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.

c) **"Contingency Reserves"**: a component of Operating Reserves which are sufficient in magnitude and response and meet the North American Electric Reliability Corporation's (NERC) disturbance control standards. Contingency reserves are comprised of spinning and supplemental reserves.

d) **"Curtailment"**: a reduction in the use of Energy by the customer, as initiated by Manitoba Hydro.

e) **"Curtailment Period"**: for Option 'A' and 'R' customers, defined as the time from which Manitoba Hydro gives the customer the "notice to curtail" to the time the "notice to restore" is given; for Option 'C' customers, defined as the time from which Manitoba Hydro gives the customer the "notice to curtail" plus one full hour to the time the "notice to restore" is given; for Option 'E' customers, from the start and stop times specified on the customer fax to curtail and restore load.

f) **"Curtailment Year"**: the 12-month period commencing upon implementation of the Terms and Conditions of the Curtailable Rate Program by Manitoba Hydro once approved by the Public Utilities Board.

g) **"Demand"**: the maximum use of power within a specified period.

h) **"Disturbance":** An unplanned event that produces an abnormal system condition; a perturbation to the electric system; or an unexpected change in the supply-demand balance that is caused by the sudden failure of generation or interruption of load.

i) **"Energy"**: power integrated over time and measured or expressed in kilowatt-hours (kWh).

j) **"Firm Load"**: load that is not considered interruptible (curtailable).

k) **"Interruption"**: discontinuance in the supply of Energy.

l) **"Load Factor"**: the ratio of a customer's average Demand over a designated period of time to the Customer's maximum Demand occurring in that period. Monthly Load Factor is found by calculating the ratio of Energy use (kWh) to highest Demand (kW) multiplied by time (usually measured at 730 hours):

$$LF = \frac{\text{Energy (kWh per month)}}{\text{Peak Demand (kW) x hours per month}}$$

m) **"MISO-MBHydro Contingency Reserve Sharing Group" or "MISO-MBHydro CRSG":** The Midwest Independent Transmission System Operator Inc. (MISO) and Manitoba Hydro balancing authorities collectively maintain, allocate, and supply operating reserves required for each entities' use in recovering from Contingencies or Disturbances on the transmission systems operated by either party. The group is established under the coordination agreement between MISO and Manitoba Hydro.

n) **"Point of Delivery":** the point at which the Corporation delivers electricity and beyond which electric service facilities (excluding meters and metering transformers) are supplied by and are the responsibility of the customer.

o) **"Power Factor":** the ratio of real power in watts of an alternating current circuit to the apparent power in volt-amperes, expressed as kW/kV.A.

p) **"Protected Firm Load (PFL)"**: the amount of load (expressed in kW) that the customer wishes to protect from being curtailed.

q) **"Peak"**: defined as all hours from 6:01 hours through 22:00 hours Monday through Friday inclusive excluding Statutory holidays

r) **"Off-Peak"**: all nighttime hours from 22:01 hours through 06:00 hours Monday through Sunday inclusive, and all hours from 0:01 hours to 24:00 hours on Saturdays, Sundays and Statutory holidays.

s) **"Operating Reserves"**: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of Spinning Reserves and Supplemental Reserves.

t) **"Operating Reserve - Spinning"**: The portion of Operating Reserve consisting of: generation synchronized to the system and fully available to serve load within the NERC defined disturbance recovery period following the Contingency or Disturbance event; or load fully removable from the system within the disturbance recovery period following the Contingency or Disturbance event.

u) **"Operating Reserve - Supplemental"**: The portion of Operating Reserves consisting of: generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the NERC defined disturbance recovery period following a Contingency or Disturbance event; or load fully removable from the system within the disturbance recovery period following a Contingency or Disturbance event.

v) **"Planning Reserves"**: The reserves needed to ensure that future load obligations at times of peak demand do not exceed supply resources.

w) **"Reference Discount"**: An amount credited to the customer each month for having Planning and/or Contingency Reserve load available.

x) **"Reserve Discount"**: An amount credited to the customer for energy curtailed each time Supplemental Reserve load is deployed under Option R.

2. CURTAILABLE LOAD OPTIONS

The following curtailable load options are available, however are subject to capacity limitations and durations as noted in Section 6:

Option 'A': Curtail within five minutes of notice for a maximum of four hours and 15 minutes per curtailment period.

Option 'C': Curtail within one hour of notice for a maximum of four hours per curtailment period.

Option 'R': Curtail within five minutes of notice for a maximum of four hours and 15 minutes per curtailment period.

Option 'E': Curtail within 48 hours of notice for a maximum of 10 days per curtailment period.

Additional description of limits on curtailments (e.g. maximum curtailments per year) is provided on Page 13.

Options 'A', 'C' or 'R' cannot be combined with each other but may be combined with Option 'E' to increase the discount. The terms and conditions of combined Options 'AE', 'CE' and 'RE' are combinations of the individual options (e.g. notice to curtail for 'AE' would be five minutes for Option 'A' curtailments and 48 hours for Option 'E' curtailments).

Customers may elect to designate part of their load as Option 'A' and another part of their load as Option 'R' provided the loads designated under each option are distinct from each other. Although the customer designates a specific portion of their load as Option 'R', Manitoba Hydro's System Operator may request a curtailment of less than the amount designated by the customer. The minimum load the Manitoba Hydro System Operator can request under Option 'R' is 5,000 kW. Manitoba Hydro will make best efforts to request a curtailment equal to the customer's contracted amount.

3. NOMINATION OF CURTAILABLE LOAD

A customer must have a minimum, nominal curtailable load of 5 MW. Customers have two options of nominating eligible curtailable load however customers designating curtailable load under Option 'R' must nominate the "Guaranteed Curtailment" option.

(i) Guaranteed Curtailment

A customer selecting this option must guarantee availability 95%[1] of the time during each curtailment year. Manitoba Hydro reserves the right to exclude customers from future participation in the program should they fail to meet this guaranteed requirement. The customer is required to nominate curtailable load equal to the amount of which is guaranteed to be reduced at the time requested. For example, a customer with a total load of 100 MW may nominate 10 MW as curtailable load and guarantee that when requested that 10 MW of load (or lesser amount if requested by Manitoba Hydro System Operator) will be shed. In order to honour this guarantee, the customer will be required to ensure that its load prior to curtailment would be such that it never falls below 10 MW plus whatever Firm Load the customer wishes to protect.

In the event the Customer is unable to have the full amount of guaranteed curtailable load available for dispatch, the Customer must provide Manitoba Hydro 48 hours verbal notice of an anticipated plant shutdown and must also notify Manitoba Hydro immediately of any unanticipated unavailability of curtailable load. The customer shall immediately notify Manitoba Hydro when the curtailable load is again available. Failure to do so will result in the same penalties as failure to curtail as outlined in Section 10.

For this customer, the Reference Discount is determined in accordance with the following formula:

Monthly Credit = GC x $/kW Credit for selected option where,

[1] The 95% availability means the customer must guarantee their designated curtailable load will be available for curtailment a minimum of 8,322 hours (8,760 hours x 95%) each curtailment year.

GC = the customer's guaranteed curtailable load

NOTE: The monthly credit will not be applied if a customer fails to provide guaranteed curtailable load for a period greater than 10% of the hours in the applicable calendar month. For example, a customer would have to have their guaranteed load available for a minimum of 648 hours in a 30-day month and 670 hours in a 31-day month. This will ensure that customers are not being paid a credit when they are shutdown for extended periods of time. The customer is still required however to maintain the 95% per year availability criteria as specified above.

(i) Curtail to Protected Firm Load

The customer nominates a Protected Firm Load below which curtailment will not occur. The curtailable portion of the customer load will be the load available above the Protected Firm Load at the time of curtailment request. With this type of nomination, there is a risk to Manitoba Hydro that there will be little or no load to curtail when a request is made: i.e. that the customer is operating at or below protected firm level when curtailment request is made.

For this customer, the Reference Discount is determined in accordance with the following formula:

Monthly Credit = (PD-PFL) x LF x $/kW Credit for Selected Option where,

PD = the customer's highest demand (kW) in the Peak billing period in the billing month.

PFL = Protected Firm Load of the customer in kW.

LF = is the customer's overall load factor during the Peak billing period in the billing month and excluding any days during which the customer complied with a curtailment request.

At Manitoba Hydro's discretion customers with load factors less than 50% during Peak periods on the curtailable portion of the load may be required to guarantee curtailable load, i.e. to take up Option 3(i).

4. CURTAILABLE RATE DISCOUNT

A Curtailable customer's bill is reduced by the curtailable load discount, calculated in accordance with the "Reference Discount" appropriate to the curtailment option selected by the customer and the formula for determining curtailable load.

Customers selecting Curtailment Option 'R' will, in addition to the Reference Discount, receive a "Reserve Discount" amount for each curtailment initiated and successfully completed. The Reserve Discount credit will be calculated based on the following formula:

Reserve Discount = LR x Du x FD, where

LR = amount of load reduction (in kW) requested by Manitoba Hydro's System Operator to the customer at the time of an Option 'R' curtailment

Du = duration of the curtailment (in hours)

FD = fixed discount amount, currently set at \$0.04 [2] per kWh

If, for example, a customer contracts for 15,000 kW of Option 'R' load, but the Manitoba Hydro System Operator only requires 10,000 kW of curtailable load, the Reserve Discount will be calculated based only on the 10,000 kW regardless of whether or not the customer load drops by an amount greater than 10,000 kW. The Reference Discount however will be calculated in accordance with the formula provided in Section 3 (i).

5. USE OF CURTAILABLE LOAD

Reserves in the form of Curtailable Load can serve two general purposes. The first purpose is to minimize disruption to Firm Load in the event of a Contingency or Disturbance. Manitoba Hydro has a Contingency Reserve obligation to the MISO-MBHydro CRSG, or successor organization, to carry a pre-defined amount of

2 The Fixed Discount amount is based on the value of carrying contingency reserves on Manitoba Hydro units.

Contingency Reserves, both Spinning and Supplemental, to respond to Contingencies and Disturbances in the MISO or Manitoba Hydro balancing areas.

The second purpose of Curtailable Load is to maintain a sufficient level of Planning Reserves and Operating Reserves to maintain reliable operation of the bulk electric system and compliance to NERC reliability standards.

Dependent on the Curtailment Option selected, Manitoba Hydro will curtail customers in response to system emergencies and to maintain Planning and Operating Reserves for the following reasons.

(i) Option 'A' and 'C' Curtailable Load

Manitoba Hydro will use curtailable load designated under Options 'A' and 'C', to_meet reliability obligations only. These include:

- to re-establish the MISO-MBHydro CRSG's or successor organization's Contingency Reserves. Once Manitoba Hydro's Contingency Reserves are deployed in response to a MISO-MBHydro CRSG's Contingency or Disturbance, Manitoba Hydro is required to re-establish Contingency Reserves within 105 minutes of the event that triggered the commitment to supply the Contingency Reserve. A curtailment may be called to reestablish those reserves;

- to protect Manitoba Firm Load or firm exports, when Operating Reserves are insufficient to avoid curtailing Firm Load. This curtailment would be called prior to Manitoba Hydro curtailing Firm Load or firm exports; and

- as Planning Reserves to meet Manitoba Hydro or its firm export customers' resource adequacy requirements.

(ii) Option 'R' Curtailable Load

The MISO-MBHydro (or successor organization) requires participants to maintain Contingency Reserves comprised of Spinning Reserves and Supplemental

Reserves. Manitoba Hydro will use curtailable load designated under Option 'R' to deploy Manitoba Hydro's Supplemental Reserves to the extent necessary, having first dispatched its own generation resources.

(iii) Option 'E' Curtailable Load

Curtailments under Option 'E' will be initiated to meet firm energy requirements in the event that Manitoba Hydro expects to be short of firm energy supplies. Option 'E' customers will be curtailed prior to Manitoba Firm Load and firm export sales.

6. MAXIMUM LEVEL OF CURTAILABLE LOAD

Manitoba Hydro, at its discretion, can limit the amount of curtailable load needed to maintain Planning and Operating Reserve levels. Load under Option 'C' will no longer be available as of one year from the date of approval of the Terms and Conditions by the Public Utilities Board (the "sunset" date). Load currently served under Option 'C' will either revert to Firm Load or, at the customer(s) discretion, revert to Option 'A' Load prior to the sunset date.

(i) Option 'A' Curtailable Load

The maximum amount of curtailable load needed under Option 'A' has been set at 180 MW assuming Option 'C' load converts to Option 'A'. If however, Option 'C' load converts to Firm Load, the cap for Option 'A' will be set at 150 MW. Manitoba Hydro may, from time-to-time, submit an Application to the Public Utilities Board for changes to this amount.

(ii) Option 'R' Curtailable Load

The maximum amount of curtailable load needed under Option 'R' has been set at 50 MW, with a maximum number of participating customers at any time limited to three. Manitoba Hydro may, from time-to-time, submit an Application to the Public Utilities Board for changes to this amount.

(iii) Option 'E' Curtailable Load

There is currently no limit proposed.

7. CONTRACTS AND TERMINATION NOTICE

(i) Discounts or credits offered by the program, as well as all other terms and conditions, are fixed from the date of approval by the Public Utilities Board unless superseded by a further order of the Public Utilities Board or unless the program is withdrawn by Manitoba Hydro.

(ii) Customers selecting the Curtailable Rate Program will be required to contract for the service. In the event that the Public Utilities Board mandates changes to the program, which in Manitoba Hydro's opinion are material, Manitoba Hydro and the customer will agree to amend the contract to incorporate the changes, failing which the contract shall terminate immediately.

(iii) Customers accepting Curtailable service for the first time may switch curtailment options (subject to capacity limitations) or switch to Firm service entirely within the first six months, unless they have entered into the Curtailable Rate Program from another interruptible rate program.

(iv) Customers who have participated in the program for a period in excess of six months may:

a) re-contract for another Curtailable Rate Option for the following changes by providing two months' written notice to Manitoba Hydro.

- switch from Option 'C' to Option 'A' prior to the sunset date ;
- add Option 'E' to any other Option

b) switch from Option 'R' to Option 'A' or from Option 'A' to Option 'R' by providing one year's written notice to Manitoba Hydro. Switching can only occur if provision allows (i.e. the maximum level of load in a particular Option will not be exceeded as per Section 6).

c) switch from Curtailable to Firm service by providing one year's written notice to Manitoba Hydro in which case Manitoba Hydro may convert the load from Curtailable to Firm service at any time during the one year notice period. The one-year notice will not apply when the customer's decision to withdraw from the program is a result of material changes mandated by the Public Utilities Board as outlined in Section 7 (ii). Customers who have switched from Curtailable to Firm service may not be permitted to switch back to Curtailable service for one year, provided Curtailable load is available as defined in Section 6.

(v) Customers may re-designate their Protected Firm Loads or Guaranteed Curtailable Load by providing 12 months' written notice to Manitoba Hydro. Decreases to Protected Firm Load and/or increases to Guaranteed Curtailable Load may be subject to capacity limitations and will be at the discretion of Manitoba Hydro. The time period may be shortened if customers are decreasing their Protected Firm Load as a result of notification by Manitoba Hydro that additional Option 'R' curtailable load is available, as described in section 6 (ii). Customers increasing their Protected Firm Load and/or decreasing their Guaranteed Curtailable Load must maintain a minimum curtailable load of 5 MW per month.

8. MANNER OF NOTICE TO CURTAIL

(i) Option 'A' ,' C' and 'R' Customers

For Option 'A' and 'R' customers, the Notice to Curtail of five minutes means that the customer must reduce the load by the contracted curtailable amount or to the contracted firm amount within five minutes of the initiation from Manitoba Hydro. For Option 'C', the Notice to Curtail of one hour means that the customer must reduce the load within one hour from the time the "Notice to Curtail" is given.

Initiation will be by telephone or by an electronic signal sent to the customer by the Manitoba Hydro System Operator. Both the initiation signal and the load response will be recorded by Manitoba Hydro.

(ii) Option 'E' Customers

Manitoba Hydro will give Option 'E' customers notice in writing that their load may be curtailed when Manitoba Hydro expects to be short of firm energy supplies. Manitoba Hydro will provide not less than 30 days notice. Notice will be deemed received three days from the date of mailing; or if faxed or sent by electronic mail, on the date that it was sent.

After the notice period has been met, Option 'E' customers will be on standby and curtailable on 48 hours notice by fax or electronic mail. Manitoba Hydro will give Option 'E' customers notice in writing whenever their standby status is withdrawn.

9. DEMAND PRO-RATION FOR OPTION 'E" CUSTOMERS

Customers curtailed under Option 'E' will have their Demand Charge prorated on the curtailable portion of load to exclude the period during which an Option 'E' curtailment was in effect. For example, if the load were curtailed for ten days in December, the Demand Charge would be reduced by 10/31 or 32% and, as well, the curtailable credit would be applied. This additional discount would apply only during months of curtailment and only to that portion of load which is curtailable. This provision will not reduce the maximum demand established for the purposes of computing the demand ratchet.

10. ADDITIONAL CHARGES FOR FAILURE TO CURTAIL

(i) Option 'A' ,'C' and 'R' Customers

The first failure to curtail load on request in any contract period will not attract additional charges, but the customer will forego the discount for that month.

After the first failure, the following additional charges will apply. First subsequent failure in any 12-month period: loss of monthly discount plus additional charge equal to discount. Second and subsequent failure in any 12-month period: loss of discount and additional charge equal to 3x discount, at which time, Manitoba Hydro will have the right to exclude the customer from further participation in the program.

(ii) Option 'E' Customers

If the customer has elected to participate in Option 'E', in the event of a single failure to curtail load, Manitoba Hydro may in its own discretion exercise one of the following remedies:

a) the normal additional charges, as described in 10 (i); or

b) twenty-four hours after the time curtailment was to have started, Manitoba Hydro may cause electricity service to the Point of Delivery to be restricted to achieve the maximum load that should have been achieved by curtailment; or

c) if load limitation as described in 10 (ii) b) is, in Manitoba Hydro's opinion, not practical or reasonable, 24 hours after the time curtailment was to have started, Manitoba Hydro may cause electricity service to the Point of Delivery to be disconnected for the remainder of the period. Disconnection shall only take place after explicit written communication with the customer and only if, otherwise, Firm Load customers would be impacted.

11. DURATION OF CURTAILMENTS

Notwithstanding the maximum single curtailment duration provisions of each of the options, Manitoba Hydro will attempt to minimize the duration.

12. UNPLANNED INTERRUPTIONS

In addition to program curtailments for which notice is provided, customers will continue to be subject to unplanned interruptions such as those due to under frequency relay operation during power system emergencies. Manitoba Hydro cannot guarantee continuous service to any class of service in Manitoba or extra provincially.

CURTAILABLE RATE PROGRAM OPTIONS FOR APPLICATION AS OF APRIL 1, 2012 UNLESS SUPERCEDED BY FURTHER ORDER OF THE PUB

Discount to Demand Charge Expressed as Percentage of Reference Discount per kW/month.

OPTIONS	TERMS AND CONDITIONS					
	Minimum Notice to Curtail	Maximum Duration Per Curtailment	Maximum Daily Hours of Curtailment	Maximum Number Curtailments Per Year	Maximum Annual Hours of Curtailment	Discount as Percentage of Reference Discount
A	5 minutes	4-1/4 Hours	6 Hours (Oct 1 - Apr 30) 10 Hours (May 1 - Sep 30)	15 Curtailments	63.75 Hours	70%
C*	1 Hour	4 Hours	8 Hours	15 Curtailments	60.00 Hours	40%
E	48 Hours	10 Days	24 Hours	3 Curtailments	720.00 Hours	35%
R	5 minutes	4-1/4 Hours	10 Hours (Apr 1 – Mar 31)	25 Curtailments	106.25 Hours	70% + Reserve Discount
A & E	Combination	Combination	Combination	18 Curtailments	783.75 Hours	100%
C & E*	Combination	Combination	Combination	18 Curtailments	780.00 Hours	70%
R & E	Combination	Combination	Combination	28 Curtailments	826.25 Hours	100% + Reserve Discount

* Options 'C' and 'CE' will no longer be available as of the sunset date.

The Monthly Reference Discount shall equal A, and shall be adjusted on April 1st of each fiscal year by the annual inflation factor, where:

A = the amount of the Reference Discount which is related to the marginal value of capacity, expressed in Canadian Dollars. The Reference Discount of $3.17 per kW/month as of April 1, 2011 shall be adjusted each year by the Inflation Factor as defined below.

Inflation Factor = at the end of each fiscal year of Manitoba Hydro, the percentage change in the Consumer Price Index for Manitoba as recorded for the most recent set of 12 month periods for which data are available.

Reserve Discount: The fixed price to be paid for energy during curtailment under Option 'R' has been set at $0.04 per kW.h.

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APPENDIX 10.5

Manitoba Hydro

REPORT TO THE PUBLIC UTILITIES BOARD

CURTAILABLE RATE PROGRAM

APRIL 1, 2011 – MARCH 31, 2012

JULY 2012

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REPORT TO PUBLIC UTILITIES BOARD
CURTAILABLE RATE PROGRAM
APRIL 1, 2011 – MARCH 31, 2012

SUMMARY

This Curtailable Rate Program (CRP) annual report covers the period April 1, 2011 to March 31, 2012. During this period, three customers participated in the program. Nine curtailments were successfully initiated, eight Option R curtailments and one Option A.

The Reference Discount of $3.17/kW of curtailable load used in 2011/12 was approved by the Public Utilities Board in Order 63/11 dated April 27, 2011. Customers received monthly credits on their electrical bill for their participation in the program totaling $5,778,940 for the year.

BACKGROUND

The CRP Terms and Conditions applicable during the reporting period April 1, 2011 to March 31, 2012 took effect April 1, 2005 in accordance with Board Order No. 28/05 dated February 17, 2005. A slight modification to the Terms and Conditions was approved in Board Order 90/08 dated June 30, 2008 which required customers to provide Manitoba Hydro 48 hours notice period of any anticipated plant shut downs.

The Terms and Conditions allow Manitoba Hydro to reserve the right to limit the amount of total curtailable load used for maintaining operating and contingency reserves[1]. The current limit is set at 230 MW under Options A and C and 100 MW under Option R. There is no limit for Option E load. The caps have been beneficial to both Manitoba Hydro and curtailable customers by ensuring the value of curtailable load does not depreciate. A decreased value would result in lower discounts paid to customers making the program less attractive to them.

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[1] Per North American Electric Reliability Council (NERC) Glossary of Terms, Operating Reserves: The reserves needed to protect Manitoba Hydro and its obligations to the Midwest Independent System Operator power system against Contingencies or Disturbances. These events are typically a result of loss of supply caused by sudden generating or transmission outages. Operating Reserves consist of various types including Contingency Reserves. Contingency Reserves: a component of Operating Reserves which are sufficient in magnitude and response to meet NERC Disturbance Control Standards. Contingency Reserves are comprised of Operating Reserves-Spinning and Operating Reserves-Supplemental. Curtailable load (also referred to as Interruptible Load) can be a source of Operating Reserves-Supplemental.

Manitoba Hydro uses curtailable load, among other measures, to maintain operating and contingency reserves as a means of minimizing disruption to firm customers in the event of loss of generation or transmission.

Curtailable load provides value to Manitoba Hydro all year round, as curtailments for system emergencies can occur at any time of the year. However, it has the greatest value during peak times as it is during the peak periods that Manitoba Hydro's capacity surplus is the most vulnerable. Additional Options A and C curtailable load in these hours increases the amount of capacity for sale in the firm export markets while additional Option R load can allow Manitoba Hydro to meet its contingency reserve obligations at a lower cost.

A significant risk mitigation benefit of curtailable load is not having to shed firm load in the event that Manitoba Hydro or the Midwest Independent System Operator-Manitoba Hydro Contingency Reserve Sharing Group (MISO-MBHydro CRSG)[2] would otherwise be in contravention of the standard(s) established by the North American Electric Reliability Council (NERC). Option R curtailable load allows Manitoba Hydro to meet reserve obligations thereby freeing up hydro generation for market transactions in the short-term opportunity energy market[3]. In this circumstance the benefits of having Option R available are dependent on Manitoba Hydro's water supply conditions as follows:

- High Water Supply - the generating capacity freed up for commercial use allows for increased hydraulic generation for export as idle generating units can be run to capture additional sales. Without Option R capacity in place energy would be spilled. With Option R load, the additional energy generated can be sold at on-peak prices.

- Average Water Supply - allows for additional hydraulic generation during on-peak hours that would otherwise be produced during off-peak hours (due to limited on-peak generating capability). In this case Manitoba Hydro captures the benefit of the price differential between on and off-peak periods.

[2] The MISO-MBHydro CRSG is a NERC registered Contingency Reserve Sharing Group that has operated since January 1, 2010. The CRSG was established under the terms of the Amended MISO-Manitoba Hydro Coordination Agreement and executed on October 9, 2009.

[3] Opportunity export sales are sales of capacity and/or energy that are not backed by dependable energy and are incremental exports that arise from time to time as a result of water conditions that are better than the lowest historic levels.

- Low Water Supply - does not provide any significant benefits because Manitoba Hydro has sufficient shut down generating units that could be run temporarily for operating reserves purposes without relying on Option R load reductions.

Manitoba Hydro will not initiate load curtailments in order to facilitate an opportunity spot market sale[4].

PERFORMANCE FOR 2011/12

Curtailment Options:

The Curtailable Rate Program consists of four base curtailment options and three combinations. Options vary dependent on: minimum notice to curtail, maximum duration per curtailment, maximum daily hours of curtailment, maximum number of curtailments per year, and maximum annual hours of curtailment.

The three customers that participated in the Curtailable Rate Program during the April 1, 2011 to March 31, 2012 period designated a total of 228 MW to Manitoba Hydro's reserves, allocated as 80 MW Option AE, 67 MW Option A, 31 MW Option C and 50 MW Option R. The amount each customer designated as curtailable load in relation to their total load varies, and therefore impacts their curtailable credit, as shown on the following table:

Summary of Curtailment Credit Data April 1, 2011 to March 31, 2012					
Customer	**Option(s)**	**CRP Load as % of Total Load**	**Average On-Peak MW**	**Average On-Peak LF**	**Average Monthly Cr.**
1	A & R & E	87%	192.4	94.0%	$430,260
2	A	94%	25.2	96.1%	$50,474
3	C	2%	33.6	68.4%	$844

Customer 1: 87% of total load represents 41% Option AE, 26% Option R and 20% Option A for 2011/12.

Load designated under Option R must be nominated as a Guaranteed Curtailment, that is, the customer must agree to shed a specified number of MW in order to be compliant with the curtailment request. Under all the other curtailment options, customers can nominate curtailable load as Guaranteed Curtailment or Curtail to Protected Firm Load.

[4] Spot market sales are sales that occur on a day ahead or real time basis. They are not considered to be a firm export sale.

Dependent on the curtailment option selected, Manitoba Hydro will curtail customers to meet reliability obligations only. Options A, C and R curtailments assist in securing operating and contingency reserves whereas Option E curtailments are initiated to meet firm energy requirements in the event that Manitoba Hydro expects to be short of firm energy supplies.

Customers may nominate different quantities of curtailable or firm load for each month provided that a minimum of 5 MW of curtailable load is available in each month. Customers must specify the 12 months Guaranteed Load or 12 months Protected Firm Load prior to participation in the program and must provide 12 months' written notice to Manitoba Hydro should they wish to increase or decrease their load in any month. This may be subject to capacity limitations and will be at the discretion of Manitoba Hydro. To date no customers have elected to differentiate their monthly load.

Implementation and Size of Curtailments:

There were 10 curtailments during the April 1, 2011 to March 31, 2012 period: one Option A and nine Option R curtailments with all curtailments being initiated to only one of the three customers. The Option A curtailment was initiated to protect firm export schedules following a MISO-MB Hydro CRSG event. The nine Option R curtailments were initiated in response to a contingency or disturbance event requiring deployment of Manitoba Hydro's supplemental reserves. The following table summarizes the duration and load in MW of each curtailment.

April 2011 to March 2012	Option 'A'		Option 'R'	
	Hrs	MW	Hrs	MW
April 11, 2011			0.82	50
May 15, 2011			0.83	50
June 24, 2011	0.23	118	0.23	50
July 15, 2011			1.48	50
July 29, 2011			0.92	50
August 9, 2011			0.50	50
September 10, 2011			1.52	50
September 11, 2011			0.85	50
November 24, 2011			2.23	50
Total	**0.23**	**118**	**9.38**	**450**
Average	**0.23**	**118**	**1.04**	**50**

All curtailments occurred during peak hours. The customer did not use an alternative power source to supply their load during the curtailments.

Manitoba Hydro continues to use telephone to communicate curtailment requirements to customers on the program. This procedure is manageable and provides the additional security that curtailment(s) will be initiated by confirmation from an agent of the customer. Manitoba Hydro experienced no difficulties in communicating the 10 curtailments during this reporting period to the customer.

Reference and Reserve Discounts:

The maximum discount available to a participating customer is called the "Reference Discount." The Reference Discount is related to the marginal value of capacity, expressed in Canadian dollars, and was set at $2.75 per kW/month as of April 1, 2005. This amount is adjusted on April 1 of each year by the inflation factor (the change in Manitoba Consumer Price Index as recorded for the most recent 12 months). Each year Manitoba Hydro submits an application for the adjusted Reference Discount to the PUB for *ex parte* approval.

The Reference Discount in effect for the reporting period April 1, 2011 to March 31, 2012 was $3.17 per kW/month, approved on April 27, 2011 via Board Order 63/11. Customers under Option AE receive 100% of the discount, while customers under Options A and R receive 70% of the discount or $2.22 per kW/month. Option C customers receive 40% of the discount or $1.27 per kW/month.

For curtailable load nominated as 'Protect to Firm Load' the Reference Discount is calculated and credited to customers' bill each month as (A - B) x C x D where:

A = On-Peak Period Demand (kW)
B = Protected Firm Load (kW)
C = On-Peak Period Load Factor
D = Discount Amount

For curtailable load designated as a 'Guaranteed Curtailment' the Reference Discount is calculated and credited to customers' bill each month as GC x D where,

GC = the customer's guaranteed curtailable load
D = Discount Amount

Customers selecting Curtailment Option R receive, in addition to the Reference Discount, a Reserve Discount for each curtailment initiated and successfully completed. The Reserve Discount represents the value of carrying contingency reserves and is calculated and credited to customers' bill for each successful curtailment as LR x Du x FD where,

> LR = amount of load reduction (in kW) requested by Manitoba Hydro's System Control to the customer at the time of an Option R curtailment
> Du = duration of the curtailment (in hours)
> FD[5] = fixed discount amount, currently set at $0.04 per kWh

The monthly Reference Discount Credit, each customer received from April 1, 2011 to March 31, 2012 as well as their monthly On-Peak Demand and On-Peak Load Factor have been itemized in the following table.

Monthly Reference Discount Credit for 2011/2012									
2011 to 2012	Customer 1 Options AE, R, A			Customer 2 Option A			Customer 3 Option C		
	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $
Apr	197.0	98.9%	$445,310	25.9	98.7%	$53,475	47.0	52.8%	$9,376
May	187.1	98.3%	$443,248	26.0	98.8%	$53,678	33.0	70.2%	$28
June	187.1	69.5%	$345,781	26.0	92.4%	$50,319	31.4	79.4%	$0
Jul	187.0	94.9%	$431,623	25.9	97.5%	$52,778	32.0	78.5%	$0
Aug	187.3	95.9%	$435,002	25.8	94.6%	$50,942	33.1	82.0%	$84
Sep	187.2	97.0%	$438,720	25.6	87.5%	$46,755	32.9	83.0%	$0
Oct	188.9	96.5%	$437,064	25.0	95.9%	$50,044	33.2	65.9%	$190
Nov	197.6	94.9%	$431,555	25.1	95.0%	$49,747	29.8	66.1%	$0
Dec	197.6	96.1%	$435,780	21.8	98.1%	$44,216	32.8	62.6%	$0
Jan	197.7	95.4%	$433,481	24.9	96.5%	$50,231	33.6	65.1%	$455
Feb	197.3	92.4%	$423,410	24.9	99.3%	$51,609	32.9	60.7%	$0
Mar	197.4	98.4%	$443,384	25.2	98.8%	$51,895	31.7	54.1%	$0
Total	**2,309.2**	**94.0%**	**$5,144,358**	**302.0**	**96.1%**	**$605,689**	**403.5**	**68.4%**	**$10,134**

The discounts shown for Customer 1 do not include the $18,760 credited in respect of the Option R Reserve Discount.

[5] The Fixed Discount amount is based on the value of carrying contingency reserves on Manitoba Hydro units.

Adequacy of Terms and Conditions:

The Terms and Conditions which have been in place since April 1, 2005 (with minor modification in 2008) have protected Manitoba Hydro's contingency reserves and provided operating reserves which satisfy the requirements of NERC and the MISO-MBHydro CRSG. However going forward, Manitoba Hydro sees the need to modify the Terms and Conditions of the program to adjust for current economic conditions. Revised Terms and Conditions have been filed as Appendix 10.4 of Manitoba Hydro's 2012/13 & 2013/14 General Rate Application.

CONCLUSION

The Curtailable Rate Program facilitates fulfilling Manitoba Hydro's commitment of carrying, deploying, and re-establishing contingency reserves to meet its obligations with the MISO-MBHydro CRSG and to maintain compliance to NERC Standards. The program also assists in minimizing disruption to Manitoba Hydro's firm customers.

The amount of curtailable load Manitoba Hydro has made available (230 MW for operating reserves and 100 MW for contingency reserves) has to date proven sufficient to meet Manitoba Hydro's requirements with respect to reserve obligations. However, Manitoba Hydro has changes to the Terms and Conditions in Appendix 10.4 of 2012/13 & 2013/14 General Rate Application.

ATTACHMENT 1

ESTIMATE OF THE VALUE OF CURTAILABLE LOAD TO MANITOBA HYDRO

The value of curtailable load to Manitoba Hydro is related to an estimate of the marginal cost of firm, long-term capacity. Over the long term, a representative value for capacity can be developed by estimating the annual carrying cost (includes finance and depreciation costs but not operating/fuel costs) of the lowest cost resource required to provide capacity to Manitoba Hydro, which is a simple cycle combustion turbine (SCCT). In 2005 the annual carrying cost of a SCCT was estimated to be $78 per kW per year, or $6.50 per kW per month, evaluated at load. It was proposed that that this cost would escalate at the rate of inflation. This cost was reviewed in 2012 and was found to be appropriate going forward. This approach has the advantage of providing a clear transparent value, which is also stable over time and is consistent with the approach that is utilized to evaluate the benefits of other resource options such as DSM that may have a capacity component.

Curtailable load is less valuable than a generation resource such as a SCCT. The SCCT can provide more flexibility in dispatch and also has the capability to deliver for longer time periods during extended emergency situations. Once in place, a SCCT can be relied upon as a permanent, long-term resource, unlike curtailable load which can be terminated with a notice period of one year. Curtailable load normally has more value in the summer months, when it can assist in supporting seasonal capacity exports, and in the peak winter months, when it may add reliability to Manitoba Hydro's generation resource. Curtailable load will provide more winter reliability benefits in years in which there is little capacity surplus on the system. When there is a significant capacity surplus on the Manitoba Hydro system, curtailable load provides less winter value than it would, for example, in the period around the year 2020, when the requirement to add generation to serve domestic customers can be expected to occur with the current load growth forecast. The value of reliability benefits in a single year is not easily determined, which is why longer-term levelized values are used to infer the benefits of curtailable load.

As described above curtailable load is less valuable than a SCCT because it has limited dispatchability, is not sustainable in reducing load over longer periods, and is not guaranteed to exist in the long term. Therefore in order to reflect these factors, curtailable load is assigned a long-term levelized value that is 42% of the annual carrying cost of a SCCT. After consideration of inflation subsequent to the 2005 base year, this yields an estimate of benefits for the year beginning April 1, 2011of $3.17 per kW/month, which is referred to as the "Reference Discount". This value would apply to the curtailable rate option that provides the most value to Manitoba Hydro, that being Options AE and RE, for which the discount is set to return 100% of the estimated value of curtailable load to the customer. Other options provide less flexibility and are accordingly worth less to Manitoba Hydro. These have been priced to reflect their lesser value to Manitoba Hydro but still to return the full estimated value of that option to the customer.

Manitoba Hydro typically markets its summer surplus capacity in the preceding winter or late spring and will market curtailable load or other surpluses up to the point that there is still a low probability of breaching reserve obligations even in very warm weather conditions. Hence the summer weather does not impact on the value received for such sales. However, as noted earlier, year to year changes in conditions in the MISO market can lead to considerable volatility in the value of capacity in that market.

In general terms Manitoba Hydro's objective for marketing curtailable capacity and energy is to utilize any excess in a manner that provides the greatest profits. This may involve the sale of additional short-term 5×16 contracts (47% capacity factor sales) if there is sufficient surplus energy, or the sale of peaking capacity which requires the supply of less energy during the on-peak period (e.g. 20% capacity factor sales).

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Manitoba Hydro

PO Box 815 • Winnipeg Manitoba Canada • R3C 2P4
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Telephone / N° de téléphone : (204) 360-3946 • Fax / N° de télécopieur : (204) 360-6147
pjramage@hydro.mb.ca

April 5, 2012

Mr. H. Singh
THE PUBLIC UTILITIES BOARD
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

Dear Mr. Singh:

RE: APPLICATION BY MANITOBA HYDRO TO EXTEND THE SURPLUS ENERGY PROGRAM ("SEP") AND VARY TERMS AND CONDITIONS

Please find enclosed a copy of Manitoba Hydro's Application to the Public Utilities Board requesting approval of the following:

1) That the SEP be made a permanent rate offering;

2) That SEP Option 1 customers be allowed to designate different Reference Levels of Demand for each pricing period; and

3) That the requirement for an Engineer's seal on the weekly application of SEP rates be removed.

The enclosed documents include Manitoba Hydro's SEP Application, the SEP Proposed Terms and Conditions, and the latest Report on the Status of the SEP covering the period November 1, 2010 to October 31, 2011.

By way of background, the SEP was first approved in Board Order No. 90/00 dated June 30, 2000. After various modifications to the Terms and Conditions regarding the notice period provision, customers began accepting SEP service on December 4, 2000.

The following is a summary of all Board Orders pertaining to the SEP since its inception:

Order No.	Date	Relating to
90/00	June 30, 2000	SEP approved by PUB to March 31, 2004
132/00	September 29, 2000	Changes to T&C's approved by PUB
143/01	September 13, 2001	Additional changes to T&C's approved by PUB
153/03	October 31, 2003	SEP approved by PUB to March 31, 2005 (*ex parte*)
101/04	July 28, 2004	SEP approved by PUB to March 31, 2007
173/06	December 21, 2006	Extension of SEP beyond Oct 31, 2007 denied by PUB

Order No.	Date	Relating to
136/07	October 26, 2007	SEP approved by PUB to April 30, 2009 (*ex parte*)
90/08	June 30, 2008	SEP approved by PUB to October 31, 2008
150/08	November 7, 2008	Confirmed SEP approved by PUB to April 30, 2009
57/09	April 28, 2009	SEP approved by PUB to March 31, 2013

As you will note, the current Terms and Conditions of the Surplus Energy Program (SEP) are set to expire as of March 31, 2013.

Manitoba Hydro thanks the Board for its consideration of this matter. If you have any questions or comments with respect to the foregoing, please do not hesitate to contact the writer.

Yours truly,
MANITOBA HYDRO LAW DEPARTMENT
Per:

ODETTE FERNANDES
Legal Counsel

Encl.

SURPLUS ENERGY PROGRAM

PROPOSED TERMS AND CONDITIONS

Manitoba Hydro

July 6, 2012

SURPLUS ENERGY PROGRAM
INDUSTRIAL LOAD - OPTION 1
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SURPLUS ENERGY PROGRAM
INDUSTRIAL LOAD - OPTION 1
TERMS AND CONDITIONS

ELIGIBILITY

1. SEP - Option 1 is available to industrial loads which meet the following qualifications:

   a) Total Demand must be 1 000 kVA or greater. Total Demand is defined as the Reference Level of Demand (as described in Section 3 below) **plus** the level of Demand associated with SEP; and

   b) Demand associated with SEP does not exceed 50 MVA **except** where the load factor of such load is guaranteed by the customer, in writing, to exceed 25% on a weekly basis; and

   c) Are not being served under the Curtailable Rate Program; and

   d) Manitoba Hydro may require a customer to maintain a minimum Power Factor of 90% as a condition of participation.

REFERENCE DEMAND

2. A customer shall designate a Reference Level of Demand (both in kV.A and kW) for each calendar month of the year. Customers have the option of designating different Reference Demands for each TOU periods (Peak, Shoulder, Off-Peak). The Reference Demand is subject to the following:

   a) The designation must be made prior to participation in SEP; and

   b) The Reference Level of Demand must equal at least 75% of Total Demand

      - *Exception*: Manitoba Hydro may allow exceptions to the 75% qualification, where a customer can demonstrate, to the satisfaction of Manitoba Hydro, that it has on-site back-up capability in the form of a generating facility or alternative equipment capable of supporting the process to which SEP is applied and, that, the back-up capability together with the Reference Level of Demand can supply 75% or more of the Total Demand; and

3. Subject to Subsections 3 b) and c), a customer may increase its designated Reference Level of Demand or may convert part or all of the load served under SEP to firm service by providing Manitoba Hydro with advance written notice based on the following notice period options, of which, must be determined and designated on Schedule 'A' of the customer's SEP contract prior to participation in SEP. In all cases Manitoba Hydro may reduce the notice period if, in its sole discretion such reduction can be accomplished without adverse impact to the operations or revenues of the corporation.

a) A 12 month notice period with an option of:

i) the customer will pay a premium of 1.0¢ per kWh for energy purchased during the summer peak hours; or

ii) the customer will agree that load converted on 12 months notice shall be subject to curtailment under the provisions of Option "A" or "R" of the Curtailable Rate Program for the first four months following the conversion; or

b) A notice period dependent on when the said notice is provided, as follows:

i) where notice is provided between September 1 up to and including January 31, a 12 month notice period shall apply; or

ii) where notice is provided between February 1 up to and including April 30, a 16 month notice period shall apply. Where the customer provides notice between February 1 and April 30, the customer may elect at the time notice is given, to convert to the notice provisions outlined in Subsection 4 a) ii) above; or

iii) where notice is provided between May 1 up to and including August 31, the notice period shall not expire prior to August 31 of the following year such that notice will be not greater than 16 months or less than 12 months. Where the customer provides notice between May 1 and August 1, the customer may elect, at the time notice is given, to convert to the notice provisions outlined in Subsection 4 a) ii) above.

BILLING

4. Energy Charges:

SEP energy is energy associated with the demand taken by a customer in excess of the monthly Reference Level of Demand(s) (in kW). Measurement of SEP energy will be based on each 15-minute interval reading of kW during a billing month.

Rates to SEP - Option 1 customers will be set as follows. The rates which will be charged are set out in Schedule SEP-1 (attached) and are subject to weekly approval by the PUB as per Schedule SEP-2 (attached).

a) i) a Basic Charge of $100.00 per month to cover administration and metering costs;

ii) an Energy Charge per kWh which will be set for three Time-of-Use periods on a weekly basis; that is, one for each of the peak, shoulder, and off-peak periods. The periods are defined below:

	Summer (May 1 - October 31)	Winter (November 1 - April 30)
Peak	Monday through Friday except Statutory Holidays from: 12:01 hours - 20:00 hours	Monday through Friday except Statutory Holidays from: 07:01 hours - 11:00 hours; and 16:01 hours - 20:00 hours
Shoulder	All hours except Peak, every day from: 07:01 hours - 23:00 hours	
Off-Peak	All night time hours from 23:01 hours - 07:00 hours	

The Weekly Energy Charge will be determined as per Schedule SEP-3 (attached).

iii) a Distribution Charge per kWh intended to collect approximately one-third of the embedded cost of distribution, subtransmission, and regional transmission.

b) All non-SEP energy will be billed at the appropriate standard General Service Large or Medium rate.

5. <u>Demand Charge</u>:

a) The demand up to the maximum monthly Reference Level of Demand in kV.A will be billed at the at the appropriate standard General Service Large or Medium rate, subject to Monthly Billing Demand criteria as set out in Subsection 6 b). In the case of different Reference Level of Demand for the TOU periods, the highest designated monthly TOU Reference Level of Demand will be used.

b) The Monthly Billing Demand in KV.A for a customer participating in SEP is the greatest of the following:

i) measured demand up to a maximum of the monthly Reference Level of Demand in kVA; or

ii) 25% of the highest annual Reference Level of Demand in kV.A

- *Exception:* In the event that a customer's demand exceeds Total Demand as defined in Subsection 2 a), the appropriate standard General Service Large or Medium Demand Charge will apply to all kVA in excess of Total Demand. The Reference Level of Demand plus the demand in excess of Total Demand will be used in determining the Monthly Billing Demand. Manitoba Hydro does not guarantee the supply of firm capacity in excess of the Reference Level of Demand.

INTERRUPTIONS

6. On notice by fax/email or phone from Manitoba Hydro, a customer will be required to reduce its load within 36 hours to its Reference Level of Demand(s) (kW) in one or more of the TOU periods as specified in the notice, and to maintain its load at or below its Reference Level of Demand(s) in the specified period(s) until notified by Hydro by fax/email or phone that the interruption is ended.

   Where the SEP load is separately metered, the customer will be required to interrupt supply to the SEP load.

7. Failure to reduce load to or below the Reference Level of Demand (kW) during an interruption can result in additional charges based on the actual costs Manitoba Hydro incurs to supply any load above the Reference Level of Demand. The maximum additional charge is $150.00 per kW of Demand and $1.00 per kWh of associated energy.

8. A customer will be subject to unplanned interruptions such as those due to under frequency relay operation during power system emergencies. Manitoba Hydro cannot guarantee continuous service to any class of service in Manitoba or extra-provincially.

METERING AND ELECTRIC SERVICE FACILITIES

9. Manitoba Hydro will supply the appropriate metering for a SEP customer.

10. The customer shall be responsible for all costs of building or upgrading regional transmission, subtransmission, distribution and/or dedicated services which may be required to serve SEP load.

CONTRACT REQUIREMENTS

11. A customer will be required to enter into a formal agreement with Manitoba Hydro. The agreement will document the above Terms and Conditions as well as any others considered necessary due to the nature of a specific service.

CUSTOMER WAIVER – NO BACK-UP FACILITIES REQUIRED

12. Where no back-up facilities are required as per Subsection 3 b), a customer will be required to sign a waiver stating that:

    a) The customer has included in its Reference Level of Demand sufficient kV.A/kW for all essential load within its operation.

    b) The customer understands that the Terms and Conditions of SEP provide for:

       i) SEP energy prices-per-kWh which can be volatile from week-to-week, and can be extremely high during periods of scarcity in interconnected markets; and

ii) interruption in the supply of SEP energy can be initiated by Manitoba Hydro on 36 hours notice to the customer for any reason; and

iii) possible lengthy periods of interruption.

c) The customer has considered the implications of the foregoing and will comply without objection to interruptions made in accordance with the Terms and Conditions of SEP.

CUSTOMER WAIVER – BACK-UP FACILITIES REQUIRED

13. Where back-up facilities are required as per Subsection 3 b):

a) A customer will be required to sign a waiver as per Subsections 13 b) and c).

b) The customer must provide certification in writing to Manitoba Hydro that:

i) the back-up facility is adequate to serve that portion of SEP load in excess of 25% of Total Demand, given the type of load and possibly lengthy interruption of SEP supply; and

ii) the installation and operation of the back-up facility complies with all government regulations including all municipal and provincial zoning and environmental regulations.

c) Certification of back-up as described in Subsections 14 b) i) and ii) must be provided in writing to Manitoba Hydro when the customer first accepts SEP service and by no later than October 1, of every year thereafter that the customer is accepting SEP service.

d) If a customer ceases, or is unable to maintain an adequate back-up facility:

i) the customer must notify Manitoba Hydro in writing of the situation immediately; and

ii) the customer must reduce its Total Demand to the Reference Level of Demand(s); and

iii) should the customer continue to use SEP, Manitoba Hydro may bill the customer for Demand (kV.A) associated with SEP energy use at the applicable General Service Large or Medium Demand Charge for the period of time the back-up facility is considered to be, or to have been, inadequate; and

iv) notice to convert load served under SEP to firm service will be as set out in Section 4.

OPTION 1
SCHEDULE SEP-1

GENERAL SERVICE ALTERNATIVE RATES
SURPLUS ENERGY PROGRAM RATE

General Service-Medium (Utility-Owned Transformer) **Tariff No. 50-19:**

Basic Monthly Charge:	$100.00
PLUS	
Distribution Charge:	0.62¢/kWh
PLUS	
Energy Charge:	
Peak Hours	______
Shoulder Hours	______
Off-Peak Hours	______

General Service-Large 750 V to Not Exceeding 30 kV **Tariff No. 50-20:**

Basic Monthly Charge:	$100.00
PLUS	
Distribution Charge:	0.33¢/kWh
PLUS	
Energy Charge:	
Peak Hours	______
Shoulder Hours	______
Off-Peak Hours	______

General Service-Large 30 kV to Not Exceeding 100 kV **Tariff No. 50-21:**

Basic Monthly Charge:	$100.00
PLUS	
Distribution Charge:	0.14¢/kWh
PLUS	
Energy Charge:	
Peak Hours	______
Shoulder Hours	______
Off-Peak Hours	______

General Service-Large Exceeding 100 kV **Tariff No. 50-22:**

Basic Monthly Charge:	$100.00
PLUS	
Distribution Charge:	0.06¢/kWh
PLUS	
Energy Charge:	
Peak Hours	______
Shoulder Hours	______
Off-Peak Hours	______

Hours	Summer (May 1 - October 31)	Winter (November 1 - April 30)
Peak	Monday through Friday except Statutory Holidays from: 12:01 hours - 20:00 hours	Monday through Friday except Statutory Holidays from: 07:01 hours - 11:00 hours; and 16:01 hours - 20:00 hours
Shoulder	All hours except Peak, every day from: 07:01 hours - 23:00 hours	
Off-Peak	All night time hours from 23:01 hours - 07:00 hours	

OPTION 1
SCHEDULE SEP-2

SURPLUS ENERGY PROGRAM
PROCEDURE FOR INTERIM EX PARTE
PUBLIC UTILITIES BOARD (PUB) APPROVAL OF SEP RATE

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1. Each Wednesday by 9:00 AM Central Time (CT), Manitoba Hydro shall:

   i) email to the Board a copy of Schedule SEP-1 which shall include the Energy Charge for the Time-of-Use periods for all General Service Medium and Large classes of service;

   ii) indicate the expected source of SEP energy (i.e. from displaced exports, Manitoba Hydro generation, or imports); and

   iii) warrant that the price has been estimated using approved methodology as set out in Schedule SEP-3.

   The "Delivered Microsoft Outlook" message for the email will serve as confirmation that the PUB has received the schedule.

2. If Schedule SEP-1 is acceptable, the PUB will provide interim *ex parte* approval of the rates and email the Interim *Ex Parte* Order to Manitoba Hydro by 2:00 PM CT the same day. If the proposed Schedule, for any reason, is not acceptable, the PUB will contact Manitoba Hydro as soon as possible and attempt to resolve any concerns. If these concerns cannot be resolved by Wednesday at 3:00 PM CT, Manitoba Hydro will then forthwith contact customers to inform them that SEP energy is not available for the following week.

3. If the PUB emails an Interim *Ex Parte* Order to Manitoba Hydro by 2:00 PM CT on Wednesday, Manitoba Hydro shall fax/email the approved rate schedule to the SEP customers by 3:00 PM CT the same day.

4. Steps 1 through 3 shall be repeated each Wednesday that SEP energy is available.

SURPLUS ENERGY PROGRAM
PROCEDURE FOR DETERMINATION OF WEEKLY ENERGY CHARGE

The SEP Energy Charge for each of the three Time-of-Use (TOU) periods shall be determined by Manitoba Hydro weekly, on a forecast basis for the following week (Monday through Sunday), as follows:

- If SEP energy displaces extra-provincial sales, the Energy Charge shall be such as to collect the revenue that would have been received from the foregone energy sales from the week to which the Energy Charge applies.

- If SEP energy is provided from purchased power, the Energy Charge shall be the amount necessary to recover the cost of the purchased power, including Transmission Service Charges, Administration Fees and Losses, plus 10% as a contribution to reserves.

- If SEP energy is provided from Manitoba Hydro generation, the Energy Charge shall be the amount necessary to collect the incremental cost of generation including Transmission Losses, plus 10% as a contribution to reserves. The latter is to administer energy and to cover a small share of fixed cost or contribution to reserves.

- In forecasting the weekly energy prices, Manitoba Hydro will consider what price experience has been under similar conditions of seasonality, expected demand and supply in the Midwest Independent Transmission System Operator (MISO) Market. An adder will be applied to each of the three TOU periods to account for market volatility or unforeseen supply costs. The adders will be adjusted as required to ensure a balance is maintained over the long-term between actual energy costs and revenues from SEP energy.

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APPENDIX 10.7

REPORT TO THE PUBLIC UTILITIES BOARD

SURPLUS ENERGY PROGRAM

NOVEMBER 1, 2010 – OCTOBER 31, 2011

Manitoba Hydro

July 6, 2012

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REPORT TO PUBLIC UTILITIES BOARD
SURPLUS ENERGY PROGRAM
NOVEMBER 1, 2010 - OCTOBER 31, 2011

BACKGROUND

The Surplus Energy Program (SEP) was first approved on June 30, 2000 by Public Utilities Board (PUB) Order No. 90/00. Customers began accepting service under the Terms and Conditions of this program on December 4, 2000. Numerous Board Orders have been issued over the years to renew the program's Terms and Conditions; the latest being Board Order 57/09 dated April 28, 2009 which approved the SEP program to March 31, 2013. The program allows customers to purchase surplus energy at market prices determined on a weekly basis for peak, shoulder, and off-peak periods.

As part of the original Board Order which approved SEP, Manitoba Hydro was directed to file annual reports on the status of the program. This is the 11th report and covers the period November 1, 2010 to October 31, 2011.

For a brief history of PUB Orders and Manitoba Hydro's applications and reports with respect to the SEP Program, please see Attachment 1.

SUMMARY OF FINDINGS

The SEP Program is performing as anticipated and is of mutual benefit to Manitoba Hydro and its customers. This revenue neutral program offers customers choice and access to surplus energy at prices similar to those paid by export customers. To obtain the benefits of the program, customers need to have sufficient flexibility in their operations to take advantage of lower price periods. Analysis shows that all SEP customers have benefited from reduced bills relative to their respective General Service firm rate during the current reporting period of November 1, 2010 through to October 31, 2011.

The cost to Manitoba Hydro for providing surplus energy to SEP customers during the current one-year period was \$602,184. Total revenue collected under SEP was \$672,493, excluding Basic Charges and Distribution Charges, resulting in net revenue of \$70,309.

The four main factors that affected SEP prices during the current year were extra-provincial market prices, water conditions, Manitoba Hydro's cost of hydraulic generation and transmission constraints to neighboring markets. While water conditions during this reporting period were above average, 80% of the Peak SEP energy supply was sourced from displaced exports, while 20% was sourced through avoided spill. For the Shoulder period, 66% was sourced through exports, and 34% through avoided spill. Avoided spill is defined as the water that would have been spilled absent of the SEP. This trend began in May and continued throughout the summer as Manitoba Hydro's reservoirs were full and surplus water had to be released from storage beyond that needed to serve domestic and export load requirements. For the Off-Peak period, 53% was sourced through exports, and 47% through avoided spill. Off-Peak energy is sourced from avoided spill during times when tie-lines to neighboring markets are fully utilized resulting from low over-night Manitoba loads combined with unused hydro generation capacity.

SEP prices during the reporting year for all three pricing periods were, on average, the lowest since the SEP has been available to customers. This situation arose as a result of weak export markets combined with high water supplies. SEP General Service Medium average prices were: On-Peak 3.615 ¢/kWh (ranging from 2.621 ¢/kWh to 5.154 ¢/kWh); Shoulder 2.753 ¢/kWh (ranging from 1.377 ¢/kWh to 3.798 ¢/kWh); and Off-Peak 1.187 ¢/kWh (ranging from 0.457 ¢/kWh to 2.535 ¢/kWh). The lowest off peak prices were a reflection of Manitoba Hydro's marginal cost of hydraulic generation when adjusted for transmission losses to load as a result of transmission constraints that limited further exports to neighboring markets.

There was no interruption in service during the 12 month reporting period.

DESCRIPTION OF PROGRAM

Eligibility:

The Program makes surplus energy available on an interruptible basis to Manitoba Hydro General Service customers. Eligible customers can participate in one of three options. The three options are:

1) Industrial Load - Option 1 - available to industrial loads whose total monthly demand is 1,000 kVA or greater. Under this option customers may only designate 25%[1] of their total load as SEP load.

[1] Customers can designate up to 50% of their load as SEP provided they have an alternate back-up source of energy to supply the amount in excess of the 25%.

2) Heating Load - Option 2 – available to electrical loads of 200 kW or greater. The electricity is to be used for space and/or water heating only and must be separately metered from the customer's firm load. Customers must have an alternate back-up energy source capable of heating the entire load in the event of an interruption.

3) Self-Generation Displacement - Option 3 – available to industrial intermittent loads with total demand between 200 kW to 50,000 kW. Load would not be considered intermittent if the average monthly load factor exceeds 25%. The load must be separately metered from the customer's firm load and must be fully backed up by generating equipment which is leased or owned by the customer and is located on the premises of the SEP load.

Billing:

All SEP customers are billed a monthly Basic Charge, Distribution Charge and an Energy Charge. The Basic Charge is $50.00 per month for customers with connected loads less than 1,000 kVA, and $100.00 per month for connected loads greater than 1,000 kVA. The Distribution Charge per kilowatt-hour ranges from $0.0006 to $0.0062 dependent on customer class. The Energy Charge per kilowatt-hour, applicable to three pricing periods, varies based on expected market prices from week-to-week. The three pricing periods are peak, shoulder and off-peak, and are further defined by season as shown in the following table:

	Summer (May 1 – October 31)	**Winter (November 1 – April 30)**
Peak	12:01 to 20:00 hours Monday to Friday Except Statutory Holidays	07:01 to 11:00 hours and 16:01 to 20:00 hours Monday to Friday Except Statutory Holidays
Shoulder	All hours except Peak, every day from 07:01 to 23:00	
Off-Peak	All night time hours from 23:01 to 07:00 hours	

PROGRAM SUBSCRIPTION

There were 26 SEP customers on the program during this reporting period, an increase of two over last year. Both customers are in the Agricultural Service Industry and were former SEP customers. Of these 26 customers, 21 are Option 2 (Heating Load) and 5 are Option 3 (Self-Generation Displacement). There are no Option 1 (Industrial Load) customers.

All the Option 2 customers are classed as General Service Medium Demand and fall under the following industry types:

Agricultural and Related Service Industries	5 customers
Educational Service Industries	11 customers
Local Government Service Industries	4 customers
Retail Food, Beverage and Drug Industries	1 customer

All the Option 3 customers are in the General Service Large Demand 750 V – 30 kV class under the following industry types:

Quarry & Sand Pit Industries	3 customers
Paper & Allied Products Industries	2 customers

All customers have appropriate back-up facilities to support their loads in the event of an interruption.

POTENTIAL CUSTOMERS

Customers in the agricultural industry continue to show interest in SEP. In addition to the two returning SEP agricultural customers a third agricultural customer is in the process of contracting for SEP for the next reporting period. Several more are considering SEP in light of the Manitoba government's consideration to ban the use of coal for space and water heating in 2014. A customer in the paper and product industry is also currently reviewing the Terms and Conditions of SEP to see if this is a viable rate option. Three consecutive years of low SEP prices is attracting customers to consider this program.

The SEP program offers savings to customers who are able to take advantage of lower price periods by scheduling their operations during times when energy prices are low. For many businesses this may not be desirable.

CUSTOMER EXPERIENCE

Experience to date indicates that the majority of customers are satisfied with the SEP Program.

There have been no difficulties encountered with communication of pricing information to customers on a timely basis. This information is faxed or emailed to customers on Wednesday

YEAR-TO-DATE RESULTS

The following is a summary of the program since its inception on December 4, 2000.

Number of Services	GS Medium	GS Large (750 V to 30 kV)	Total
December 4, 2000 to October 31, 2001	24	4	28
November 1, 2001 to October 31, 2002	27	6	33
November 1, 2002 to October 31, 2003	27	6	33
November 1, 2003 to October 31, 2004	25	6	31
November 1, 2004 to October 31, 2005	22	6	28
November 1, 2005 to October 31, 2006	22	6	28
November 1, 2006 to October 31, 2007	22	5	27
November 1, 2007 to October 31, 2008	20	5	25
November 1, 2008 to October 31, 2009	19	5	24
November 1, 2009 to October 31, 2010	19	5	24
November 1, 2010 to October 31, 2011	21	5	26

Actual SEP Sales (MWh)	
December 4, 2000 to October 31, 2001	18,123
November 1, 2001 to October 31, 2002	28,808
November 1, 2002 to October 31, 2003	19,473
November 1, 2003 to October 31, 2004	19,328
November 1, 2004 to October 31, 2005	25,013
November 1, 2005 to October 31, 2006	22,927
November 1, 2006 to October 31, 2007	22,152
November 1, 2007 to October 31, 2008	22,347
November 1, 2008 to October 31, 2009	23,393
November 1, 2009 to October 31, 2010	19,506
November 1, 2010 to October 31, 2011	25,568
Total	**246,638**

Revenue from SEP Sales	Basic Charge	Distribution Charge	Energy Charge	Total
December 4, 2000 to October 31, 2001	$15,436	$105,948	$880,033	$1,001,418
November 1, 2001 to October 31, 2002	$20,169	$164,565	$959,529	$1,144,263
November 1, 2002 to October 31, 2003	$21,330	$111,347	$1,061,522	$1,194,200
November 1, 2003 to October 31, 2004	$21,700	$112,572	$1,201,434	$1,335,707
November 1, 2004 to October 31, 2005	$20,180	$147,530	$1,277,816	$1,445,526
November 1, 2005 to October 31, 2006	$19,200	$134,445	$1,248,314	$1,401,959
November 1, 2006 to October 31, 2007	$19,178	$128,724	$1,414,933	$1,562,835

Revenue from SEP Sales - continued	Basic Charge	Distribution Charge	Energy Charge	Total
November 1, 2007 to October 31, 2008	$17,150	$131,068	$1,149,472	$1,297,689
November 1, 2008 to October 31, 2009	$16,790	$139,021	$932,076	$1,087,887
November 1, 2009 to October 31, 2010	$16,800	$115,817	$594,374	$726,991
November 1, 2010 to October 31, 2011	$17,650	$152,400	$672,493	$842,543
Total				**$13,041,017**

Marginal Cost of Energy to Manitoba Hydro	
December 4, 2000 to October 31, 2001	$891,308
November 1, 2001 to October 31, 2002	$994,233
November 1, 2002 to October 31, 2003	$1,056,307
November 1, 2003 to October 31, 2004	$992,650
November 1, 2004 to October 31, 2005	$1,241,792
November 1, 2005 to October 31, 2006	$1,161,379
November 1, 2006 to October 31, 2007	$1,392,736
November 1, 2007 to October 31, 2008	$1,138,131
November 1, 2008 to October 31, 2009	$842,510
November 1, 2009 to October 31, 2010	$577,384
November 1, 2010 to October 31, 2011	$602,184
Total	**$10,890,614**

Manitoba Hydro Net Revenue	
December 4, 2000 to October 31, 2001	($11,275)
November 1, 2001 to October 31, 2002	($34,704)
November 1, 2002 to October 31, 2003	$5,215
November 1, 2003 to October 31, 2004	$208,784
November 1, 2004 to October 31, 2005	$36,024
November 1, 2005 to October 31, 2006	$86,935
November 1, 2006 to October 31, 2007	$22,197
November 1, 2007 to October 31, 2008	$11,341
November 1, 2008 to October 31, 2009	$89,565
November 1, 2009 to October 31, 2010	$16,990
November 1, 2010 to October 31, 2011	$70,309
Total	**$501,381**

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MANITOBA	)	Order No. 134 /10
	)	
THE PUBLIC UTILITIES BOARD ACT	)	December 22, 2010

BEFORE: Graham Lane, C.A., Chairman
Robert Mayer, Q.C., Vice-Chair
Dr. Kathi Avery Kinew, Member

DIESEL GENERATED ELECTRICITY RATES – EFFECTIVE JANUARY 1, 2011:

FOR THE COMMUNITIES OF BARREN LANDS FIRST NATION AND BROCHET; NORTHLANDS DENESULINE FIRST NATION (LAC BROCHET); SAYISI DENE FIRST NATION (TADOULE LAKE); AND SHAMATTAWA FIRST NATION (SHAMATTAWA)

9. IT IS THEREFORE ORDERED THAT:

1. MH's Application for Revised diesel generated electricity rates BE AND IS HEREBY VARIED AS FOLLOWS:

   a) MH's Application, to include in the Revenue Requirement $222,842.00 of interest expense and $357,655.00 of depreciation expense (on unrecovered capital costs of $4.4 million since April 1st, 2004), BE AND IS HEREBY DENIED.
   b) The Full Cost Rate be recalculated to remove interest and depreciation expenses;
   c) A Tail Block rate of 35 cents/kWh for electricity consumption in excess of 2,000 kWh per month (for Residential and General Service non-government accounts) be established;
   d) MH's Application to transfer the accounts of the Provincial Government and agencies to the General Service class BE AND IS HEREBY DENIED.

2. MH is to re-file, for Board approval, its proposed rates and all supporting schedules reflecting the decisions of the Board in this Order, to be effective for all electricity consumed in the Diesel Zone on and after January 1, 2011.

3. MH file with the Board and all Parties to this Diesel Zone Application:
   a) Confirmation that the Settlement Agreement (from the 2004 Minutes of Settlement) has been fully executed;
   b) A true copy of the fully executed Settlement Agreement;

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c) Confirmation of payments or adequate funding arrangements for the capital costs incurred by MH, by community, since 2004; and

d) Indication of capital costs still in dispute, if any, and the process and timeline for resolution of such dispute(s).

4. MH, supported by the written consents of INAC, MKO, the four First Nations and CAC/MSOS, is to seek an Order of this Board to confirm, as final, all Diesel Zone rates approved on an interim basis since 2004, including those interim rate approvals in Board Orders 17/04; 46/04; 159/04; 176/06.

5. MH to advise the Board and all Parties to this Application as to the Utility's ability to provide electronic spreadsheets, as well as any attendant incremental costs had this application been filed with electronic spreadsheets.

6. In the event that there is no positive support for removing the service restrictions, including the 60 Amp restriction, and eliminating the use of diesel fuel to supply power to the off-grid communities, Manitoba Hydro is to develop and file with the Board, within one year of the issuance of this Order, a five year fully costed plan to migrate Residential and non-government General Service Diesel Zone customers to grid rates for all consumption.

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Manitoba Hydro

PUBLIC UTILITIES BOARD

APPLICATION CONCERNING ELECTRIC RATES IN REMOTE COMMUNITIES SERVED BY DIESEL GENERATION

DECEMBER 2011

SCHEDULE 1

PROSPECTIVE DIESEL COST OF SERVICE STUDY
CALCULATION OF FULL COST RATE
FOR FISCAL YEAR ENDING MARCH 31,2012

Community	kW.h Consumption	Oper Costs Distrib	Int on Fuel Inventory	Oper Costs Generation	Total Var. Costs	Variable ¢/kW.h
		VARIABLE COSTS				
Brochet	2,788,738	$ 161,398	$ 90,347	$ 1,279,481	$ 1,531,226	54.9
Lac Brochet	3,372,500	117,709	94,457	1,517,656	1,729,822	51.3
Shamattawa	4,845,500	160,532	145,718	1,997,476	2,303,726	47.5
Tadoule Lake	2,265,300	144,276	62,632	1,332,411	1,539,319	68.0
Total Cost	13,272,038	$ 583,915	$ 393,154	$ 6,127,024	$ 7,104,093	53.5

Add: Provision for unrecovered capital	747,607
Revised Revenue Requirement	$ 7,851,700
Total forecast conumption for 2011/12	13,272,038
Full Cost Rate	**0.5916**

SCHEDULE 2

DIESEL COST OF SERVICE STUDY
CONSOLIDATED STATEMENT OF OPERATIONS
For actual years 2010 & 2011 and forecast 2012

	2010 Actual	2011 Actual	2012 Forecast @ existing approved rate
Revenue-Consumption	4,641,932	4,919,545	6,318,962
Direct Costs:			
Generation Mtce	1,196,573	1,457,775	1,441,547
Fuel Hauling	3,870,610	3,924,786	4,423,916
Major/Minor Overhaul	132,569	1,907	74,924
Generation Support Stand by	30,849	49,172	65,226
Hazardous Waste Disposal	94,676	56,352	121,411
Dist Facility Mtce	132,115	189,710	102,937
Distribution Mtce	112,372	136,410	120,823
Customer Service	183,468	222,475	183,695
Consumer Support	29,642	52,076	176,461
Interest on Fuel Storage	324,789	324,789	393,154
Total Direct Costs	6,107,662	6,415,453	7,104,094
Surplus (Deficit) on Total Cost	(1,465,730)	(1,495,908)	(785,132)
Statistics:			
kW.h Consumption	13,000,702	13,046,523	13,272,038
Revenue Per kW.h	0.36	0.38	0.48
Cost Per kW.h	0.470	0.492	0.535
Revenue Cost Coverage	76%	77%	89%

SCHEDULE 3

Summary of Interest & Depn Expense on Post 2004 Capital

Item	Year	Cap Cost	AANDC Paid	Other Gov Share	MH Share	Capital to Rev Req	Accrued Interest	Depn Exp	Interest Exp
Brochet									
Fall Arrest Protection	2005-08	454,770	(205,101)	73,673	175,996	73,673	61,028	-	14,527
Soil Remediation	2007	2,871,924	-	-		1,295,238	550,439	409,241	131,028
Well Monitoring Installat	2008	27,687	(12,487)	4,485	10,715	4,485	3,299	-	785
Engine Failures	2009	85,837	(38,712)	13,906	33,219	13,906	6,615	-	1,575
Misc Small Capital	2009-10	11,530	(5,200)	1,868	4,462	1,868	889	-	212
Total Brochet		3,451,747	(261,500)	93,931	224,392	1,389,169	622,271	409,241	148,127
Lac Brochet									
Fall Arrest Protection	2005-08	513,184	(436,206)	23,093	53,884	23,093	95,892	-	22,826
Well Monitoring Instal	2008	31,326	(26,627)	1,410	3,289	1,410	5,450	-	1,297
Engine Failures	2010	138,000	(117,300)	6,210	14,490	6,210	7,534	-	1,793
Misc Small Capital	2009-10	53,391	(45,382)	2,403	5,606	2,403	6,008	-	1,430
Total Lac Brochet		735,900	(625,515)	33,116	77,270	33,116	114,884	-	27,347
Shamattawa									
Fall Arrest Protection	2005-08	401,359	(297,407)	31,707	72,245	31,707	73,121	-	17,406
Potable Water Supply	2009	96,550	-	-		71,544	13,907	7,688	3,311
Engine Failures	2009-11	601,931	(446,031)	47,553	108,348	47,553	62,054	-	14,771
Powerhouse Mods	2005-07	304,858	(225,900)	24,084	54,874	24,084	85,072	-	20,251
Misc Small Capital	2009-10	39,160	(29,018)	3,094	7,049	3,094	4,037	-	961
Minor Overhaul Contrib	2010	(25,615)	(18,981)	6,634	-	6,634	405	-	96
Minor Overhaul	2010	118,895	(18,981)	9,393	90,521	9,393	28,233	4,055	6,721
Total Shamattawa		1,418,243	(1,017,336)	113,072	242,515	184,615	238,597	7,688	56,796
Tadoule Lake									
Fall Arrest Protection	2005-08	441,115	(349,805)	44,994	46,317	44,994	84,020	-	20,000
Heat Recovery System	2005	43,343	-	-		34,371	17,652	9,372	4,202
Well Monitoring Install	2008	33,047	(26,206)	3,371	3,470	3,371	5,750	-	1,369
Engine Failures	2010	33,047	-	-		118,950	14,955	21,107	3,560
Misc Small Capital	2009-11	150,000	(16,084)	2,069	131,847	2,069	2,282	-	543
Major Overhaul Gen Set	2010	20,283	-	-		184,472	23,192	32,734	5,521
Total Tadoule Lake		720,835	(392,095)	50,433	181,634	388,227	147,851	63,213	35,195
Total All Diesel Sites		6,326,726	(2,296,447)	290,552	725,811	1,995,126	1,123,602	**480,142**	**267,465**
			Total Capital Revenue Requirement Addition						**747,607**

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BILL COMPARISONS FOR PROPOSED DIESEL RATES EFFECTIVE SEPTEMBER 1, 2012

Residential (559 customers)

kWh	No. of Customers	Current April 1, 2012 $ / Month	Proposed September 1, 2012 $ / Month	Difference in $ / Month	Percent Change
250	28	$23.78	$24.23	$0.45	1.89%
750	119	$57.63	$58.98	$1.35	2.34%
1 000	92	$74.55	$76.35	$1.80	2.41%
2 000	277	$142.25	$145.85	$3.60	2.53%
5 000	53	$345.35	$354.35	$9.00	2.61%

General Service (112 Customers)

kWh	No. of Customers	Current April 1, 2012 $ / Month	Proposed September 1, 2012 $ / Month	Difference in $ / Month	Percent Change
750	48	$71.80	$73.58	$1.78	2.48%
2 000	21	$160.55	$164.45	$3.90	2.43%
5 000	12	$1,210.55	$1,283.45	$72.90	6.02%
10 000	9	$2,960.55	$3,148.45	$187.90	6.35%

Government and First Nation Education (66 Customers)

kWh	No. of Customers	Current April 1, 2012 $ / Month	Proposed September 1, 2012 $ / Month	Difference in $ / Month	Percent Change
750	20	$1,616.05	$1,721.55	$105.50	6.53%
2 000	11	$4,278.55	$4,559.05	$280.50	6.56%
5 000	8	$10,668.55	$11,369.05	$700.50	6.57%
10 000	4	$21,318.55	$22,719.05	$1,400.50	6.57%

Number of customers based on 2011 System Load Forecast for fiscal year 2012/13 and Bill Frequency Distributions for 2011/12.

SCHEDULE 4.1

CALCULATION OF RESIDENTIAL CLASS REVENUE @ PROPOSED RATES EFFECTIVE SEPTEMBER 1, 2012

Forecast Revenue Requirement and Revenue

Total Forecast kWh for 2012/13	7,954,819
Calculated Full Cost Rate	$0.5916
Gross Revenue Requirement	$4,706,071
Less: Residential Revenue (Below)	($598,810)
Unrecovered Revenue Requirement	$4,107,261

Block Rates as Follows:

Basic Monthly Charge	6.85 $/month	x	6,708	=	45,950
All kWh/month	6.950 ¢/kWh	x	7,954,819	=	552,860
Revenue			7,954,819		598,810

SCHEDULE 4.2

CALCULATION OF GENERAL SERVICE CLASS REVENUE @ PROPOSED RATES EFFECTIVE SEPTEMBER 1, 2012

Forecast Revenue Requirement and Revenue

Total Forecast kWh for 2012/13	3,353,080
Calculated Full Cost Rate	$0.5916
Gross Revenue Requirement	$1,983,682
Less: General Service Revenue (Below)	($896,362)
Unrecovered Revenue Requirement	$1,087,320

Block Rates as Follows:

Basic Monthly Charge	19.05 $/month	x	1,348	=	25,679
First 2,000 kWh/month	7.270 ¢/kWh	x	1,265,455	=	91,999
Balance of kWh/month	37.300 ¢/kWh	x	2,087,625	=	778,684
Revenue			3,353,080		896,362

SCHEDULE 4.3

CALCULATION OF GOVERNMENT SURCHARGE @ PROPOSED RATES EFFECTIVE SEPTEMBER 1, 2012

Government Revenue Requirement

Total Forecast kWh for 2012/13		2,155,000
Calculated Full Cost Rate	$	0.5916
Government Revenue Requirement	$	1,274,898
Less: Revenue from Basic Charge		(14,692)
Revenue for Energy Rate		1,260,206
Energy Rate before Government Unit Sudsidy	$	0.5848

Calculation of Government Unit Subsidy

Unrecovered Residential Revenue Requirement (Schedule 1)	$	3,260,168
Unrecovered General Service Revenue Requirement (Schedule 2)	$	869,115
Total	$	4,129,283

Government Rate based on full cost

Full Cost Rate less Basic Monthly Charge		0.5850
Unit Subsidy		1.9160
Indicative Government Rate based on full cost	$	2.501

Government Surcharge Rate

Calculated Energy Rate plus Government Unit Subsidy at Full Cost	$	2.500
Proposed Government Rate (current + 6.5%)	$	2.270
Difference between indicative and proposed government rate	$	0.230
Total Government consumption (kWh)		2,155,000
Additional Deficit due to capped government rate	$	495,650

SCHEDULE 4.4

DIESEL SERVED COMMUNITIES
PROJECTED STATEMENT OF INCOME (LOSS)
FOR YEAR ENDING MARCH 31, 2013
(in thousands of dollars)

Revenue (at proposed rates)

	Residential	General Service	Government	Total
Brochet	$ 134	$ 153	$ 896	$ 1,182
Lac Brochet	148	213	1,603	1,963
Shamattawa	226	311	1,894	2,431
Tadoule Lake	91	220	514	825
Total	$ 599	$ 896	$ 4,907	$ 6,402

Expense

Fuel Cost (incl delivery & fees)	$ 4,424
Operating Expense (Labour & Mtce)	2,680
Finance Expense	267
Depreciation	480
Total	$ 7,851
Net Income (Loss)	$ (1,449)

SCHEDULE 4.5

CALCULATION OF CUSTOMER CLASS REVENUE @ PROPOSED RATES

Fiscal Yr 2013	Block 1 kWh	Block 2 kWh	Run Off kWh	Total kWh	Bills	Revenue	Avg Use	Block 1	Rate	Block 2	Rate	Run Off Rate	Basic Chg
Residential													
2013	7,954,819			7,954,819	6,708	$598,810	1,186	900	0.0695	2,000	0.0695	0.0695	$ 6.85
General Service													
2013	1,265,455	2,087,625		3,353,080	1,348	$896,362	2,487	2,000	0.0727			0.3730	$ 19.05
Federal Government													
2013			1,773,500	1,773,500	546	$4,036,246	3,248					2.27	$ 19.05
Provincial Government													
2013			381,500	381,500	246	$870,691	1,551					2.27	$ 19.05
				13,462,899	8,848	6,402,110							

Class Revenue Requriement ^ 7,964,651

Surplus/(Deficit) ($1,562,541)

^ - estimated costs for 2012/13 based on total kWh at $0.5916

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BILL COMPARISONS

INTERIM
SEPTEMBER 1, 2012 RATES

VS

PROPOSED
APRIL 1, 2013 RATES

Manitoba Hydro

November 2012

Bill Comparison

Residential

Forecast Customers: 461,353

kW.h	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
250	$24.20	$24.86	$0.66	2.7%
750	$58.90	$60.87	$1.97	3.3%
1 000	$76.25	$78.87	$2.62	3.4%
2 000	$145.65	$150.89	$5.24	3.6%
5 000	$353.85	$366.95	$13.10	3.7%

Residential Seasonal

Forecast Customers: 21,461

kW.h	Sept 1, 2012 $ / Summer	April 1, 2013 $ / Summer	Difference in $ / Summer	Percent Change
250	$99.55	$100.21	$0.66	0.7%
750	$134.25	$136.22	$1.97	1.5%
1 000	$151.60	$154.22	$2.62	1.7%
2 000	$221.00	$226.24	$5.24	2.4%
5 000	$429.20	$442.30	$13.10	3.1%

Residential Diesel

Forecast Customers: 564

kW.h	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
250	$24.20	$24.86	$0.66	2.7%
750	$58.90	$60.87	$1.97	3.3%
1 000	$76.25	$78.87	$2.62	3.4%
2 000	$145.65	$150.89	$5.24	3.6%
5 000	$353.85	$366.95	$13.10	3.7%

Bill Comparison

General Service Small
< 50 kV.A

Forecast Customers: 51,971

kW.h	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
750	$73.23	$75.81	$2.58	3.5%
2 000	$164.35	$170.15	$5.80	3.5%
5 000	$383.05	$396.56	$13.51	3.5%
10 000	$747.55	$773.91	$26.36	3.5%

General Service Small
51 kV.A

Forecast Customers: 12,610

Load Factor	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
25%	$713.25	$738.10	$24.85	3.5%
50%	$1,221.92	$1,265.05	$43.13	3.5%
75%	$1,548.03	$1,609.38	$61.35	4.0%
100%	$1,858.88	$1,938.57	$79.69	4.3%

General Service Small
100 kV.A

Forecast Customers: 12,160

Load Factor	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
25%	$1,622.40	$1,664.87	$42.47	2.6%
50%	$2,253.45	$2,331.70	$78.25	3.5%
75%	$2,863.00	$2,977.20	$114.20	4.0%
100%	$3,472.55	$3,622.71	$150.16	4.3%

Bill Comparison

General Service
Seasonal

Forecast Customers: 859

kW.h	Sept 1, 2012 $ / Summer	April 1, 2013 $ / Summer	Difference in $ / Summer	Percent Change
750	$277.28	$287.12	$9.84	3.5%
2 000	$368.40	$381.46	$13.06	3.5%
5 000	$587.10	$607.87	$20.77	3.5%
10 000	$951.60	$985.22	$33.62	3.5%

General Service
Diesel

Forecast Customers: 113

kW.h	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
750	$73.23	$75.81	$2.58	3.5%
2 000	$164.35	$170.15	$5.80	3.5%
5 000	$1,283.35	$1,289.15	$5.80	0.5%
10 000	$3,148.35	$3,154.15	$5.80	0.2%

General Service
Government and First Nation Education

Forecast Customers: 67

kW.h	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
750	$1,721.05	$1,721.71	$0.66	0.0%
2 000	$4,558.55	$4,559.21	$0.66	0.0%
5 000	$11,368.55	$11,369.21	$0.66	0.0%
10 000	$22,718.55	$22,719.21	$0.66	0.0%

Bill Comparison

General Service Medium
500 kV.A

Forecast Customers: 1,964

Load Factor	Sept1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
25%	$7,504	$7,689	$185	2.5%
50%	$10,551	$10,916	$365	3.5%
75%	$13,599	$14,144	$545	4.0%
100%	$16,647	$17,371	$724	4.3%

General Service Medium
1 000 kV.A

Forecast Customers: 1,964

Load Factor	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
25%	$14,826	$15,191	$365	2.5%
50%	$20,922	$21,646	$724	3.5%
75%	$27,017	$28,101	$1,084	4.0%
100%	$33,113	$34,556	$1,443	4.4%

Bill Comparison

General Service Large - 750V to 30 kV
5 000 kV.A

Forecast Customers: 301

Load Factor	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
25%	$64,953	$66,513	$1,560	2.4%
50%	$93,605	$96,726	$3,121	3.3%
75%	$122,258	$126,939	$4,681	3.8%
100%	$150,910	$157,152	$6,242	4.1%

General Service Large - 30 kV to 100 kV
10 000 kV.A

Forecast Customers: 42

Load Factor	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
25%	$115,390	$118,091	$2,701	2.3%
50%	$168,680	$174,082	$5,402	3.2%
75%	$221,970	$230,073	$8,103	3.7%
100%	$275,260	$286,064	$10,804	3.9%

General Service Large - Over 100 kV
50 000 kV.A

Forecasted Customers: 13

Load Factor	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
25%	$534,738	$546,874	$12,136	2.3%
50%	$792,975	$817,248	$24,273	3.1%
75%	$1,051,213	$1,087,621	$36,408	3.5%
100%	$1,309,450	$1,357,995	$48,545	3.7%

Bill Comparison

LUBD - General Service Small
100 kV.A

Forecast Customers: 62

Load Factor	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
5%	$435.01	$443.24	$8.23	1.9%
10%	$736.86	$752.39	$15.53	2.1%
15%	$1,038.72	$1,061.55	$22.83	2.2%
20%	$1,340.57	$1,370.70	$30.13	2.2%

Bill Comparison

LUBD - General Service Medium
500 kV.A

Forecast Customers: 21

Load Factor	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
5%	$2,499.88	$2,536.38	$36.50	1.5%
10%	$4,009.15	$4,082.15	$73.00	1.8%
15%	$5,518.43	$5,627.93	$109.50	2.0%
20%	$7,027.70	$7,173.70	$146.00	2.1%

Bill Comparison

LUBD - General Service Large - 750 V to 30 kV
5 000 kV.A

Forecast Customers: 4

Load Factor	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
5%	$22,459	$22,788	$329	1.5%
10%	$35,818	$36,475	$657	1.8%
15%	$49,177	$50,163	$986	2.0%
20%	$62,536	$63,850	$1,314	2.1%

LUBD - General Service Large - 30 kV to 100 kV
10 000 kV.A

Forecast Customers: 0

Load Factor	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
5%	$39,325	$39,836	$511	1.3%
10%	$63,050	$64,072	$1,022	1.6%
15%	$86,775	$88,308	$1,533	1.8%
20%	$110,500	$112,544	$2,044	1.8%

LUBD - General Service Large - Over 100 kV
50 000 kV.A

Forecast Customers: 2

Load Factor	Sept 1, 2012 $ / Month	April 1, 2013 $ / Month	Difference in $ / Month	Percent Change
5%	$180,000	$182,373	$2,373	1.3%
10%	$289,500	$294,245	$4,745	1.6%
15%	$399,000	$406,118	$7,118	1.8%
20%	$508,500	$517,990	$9,490	1.9%