Section:	Tab 3: Appendix 3.5	Page No.:	PUB/MH I-7a,b,c
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Projected Rate Increase		
Issue:	Rate Increases Alternative Scenarios		

PREAMBLE TO IR (IF ANY):

The analysis provided does not address the full $978 million in forecast losses. MH is forecasting losses of $52 million in 2025 and $24 million in 2026.

QUESTION:

a) Please update the response to a, b,& c to include the full 20 year forecast, including the forecast losses in years 2025 and 2026.

b) Please provide an update to PUB/MH I-7(a) and PUB/MH I-7 (b) assuming 50% of the forecast shortfall is recovered from reduced operating expenses over the next ten years. Please file the analysis for the full 20 year forecast.

c) Provide an update to PUB/MH I-7(a) and PUB/MH I-7 (c) assuming 25% of the forecast shortfall is recovered from reduced operating expenses over the next 10 years. Please file the analysis for the full 20 year forecast.

RATIONALE FOR QUESTION:

To assess the impact of different assumptions on MH's operating deficit.

RESPONSE:

The attached tables provide a summary of the rate increase and/or OM&A reduction scenarios that would be necessary to mathematically eliminate all or a portion of the cumulative net losses in MH14.

As discussed in Appendix 5.5 (page 2), the Corporation is implementing a number of cost containment initiatives which focus primarily on the reduction of approximately 330 operational positions in order to achieve the committed 1% average annual increase in OM&A costs over the 2014/15 through 2016/17 period. While these reductions assist the Corporation in meeting its OM&A targets through to 2016/17, Manitoba Hydro will be reviewing other options, including additional EFT reductions in order to meet the OM&A targets forecasted in MH14 beyond 2016/17. It is estimated that approximately 595 additional EFT reductions would be necessary to achieve the OM&A targets in MH14 through to 2023/24. These reductions assume wage and salary increases of 3.5% annually, consistent with historical collective agreements, merit and progression of staff.

The EFT reductions that would be necessary to absorb all or a portion of the forecasted losses are in addition to the estimated 900 plus EFT reductions required to meet the OM&A targets in MH14 over the next ten years. The EFT reductions provided in the attached table are for illustrative purposes only. These reductions combined with the reductions necessary to meet the OM&A targets in MH14 are not plausible as they would impair the Corporation's ability to provide safe and reliable service.

Projected financial statements corresponding to each scenario are also provided below.

IR Response	Cumulative Net Losses	Loss Reduction Targeted	Reductions Achieved through	Even Annual Rate Increases 2016-2024	EFT Reductions assumed in MH14	Additional EFT Reductions 2016-2024 to absorb losses	Total EFT Reductions	% EFT Reductions to Total Workforce	% EFT Reductions to Total Operating, Maintenance, Governance, Support & Services Functions
PUB/MH-I-7a	$900 million to 2024	100% reduction in losses	100% O&M	-	926	2 528*	3 454	53%*	81%*
PUB/MH-I-7b	$900 million to 2024	100% reduction in losses	100% rate increases	5.30%		-		-	-
PUB/MH-I-7c	$450 million to 2024	50% reduction in losses	100% rate increases	4.44%		-		-	-
PUB/MH-II-1a(i)	$980 million to 2026	100% reduction in losses	100% O&M	-	926	2 528*	3 454	53%*	81%*
PUB/MH-II-1a(ii)	$980 million to 2026	100% reduction in losses	100% rate increases	no change from PUB/MH-I-7b		-		-	-
PUB/MH-II-1a(iii)	$490 million to 2026	50% reduction in losses	100% rate increases	no change from PUB/MH-I-7c		-		-	-
PUB/MH-II-1b	$980 million to 2026	100% reduction in losses	50% O&M/50% rate increases	4.64%	926	1 139	2 065	32%	48%
PUB/MH-II-1c	$490 million to 2026	50% reduction in losses	50% O&M/50% rate increases	4.19%	926	397	1 323	20%	31%

* PUB/MH-I-7a EFT reduction has been revised due to inflationary increases that were inadvertently removed in the original response.

PUB/MH II-1a(i): 100% of the losses, 100% covered b reducing EFTs

ANALYSIS OF EFT REDUCTIONS TO ELIMINATE FORECASTED LOSSES
(in millions of dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
EFT reductions to achieve approved MH14 OM&A Targets in test years	146	91	94								331
Projected EFT reductions to achieve approved MH14 OM&A Targets from 2018-2024				95	100	100	100	65	65	70	595
											926
Required annual reduction to OM&A to cover 100% of losses	-	$ 19	$ 40	$ 64	$ 91	$ 121	$ 153	$ 188	$ 226	$ 268	
EFT reductions to eliminate 100% of losses	-	190	207	232	261	285	297	324	353	378	2 528
Total EFT Reductions to meet MH14 targets and eliminate losses	146	281	301	327	361	385	397	389	418	448	3 454
% of Total Straight Time EFTs											53%
% of Total Operations & Maintenance /Govenance and Support Services EFTs											81%

PUB/MH II-1b: 100% of the losses , 50% coverd by reducing EFTs

ANALYSIS OF EFT REDUCTIONS TO ELIMINATE FORECASTED LOSSES
(in millions of dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
EFT reductions to achieve approved MH14 OM&A Targets in test years	146	91	94								331
Projected EFT reductions to achieve approved MH14 OM&A Targets from 2018-2024				95	100	100	100	65	65	70	595
											926
Required annual reduction to OM&A	-	$ 10	$ 21	$ 33	$ 45	$ 59	$ 73	$ 89	$ 104	$ 121	
EFT reductions to eliminate losses	-	99	106	116	121	129	135	143	143	148	1 139
Total EFT Reductions	146	190	200	211	221	229	235	208	208	218	2 065
% of Total Straight Time EFTs											32%
% of Total Operations & Maintenance /Govenance and Support Services EFTs											48%

PUB/MH-II-1c: 50% of the losses, 50% covered by reducing EFTs

ANALYSIS OF EFT REDUCTIONS TO ELIMINATE FORECASTED LOSSES
(in millions of dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
EFT reductions to achieve approved MH14 OM&A Targets in test years	146	91	94								331
EFT reductions to achieve existing 1% target increases in MH14				95	100	100	100	65	65	70	595
											926
Required annual reduction to OM&A	-	$ 4	$ 7	$ 12	$ 16	$ 21	$ 26	$ 31	$ 36	$ 42	
EFT reductions to eliminate losses	-	35	37	41	42	45	47	49	49	51	397
Total EFT Reductions	146	126	131	136	142	145	147	114	114	121	1 323
% of Total Straight Time EFTs											20%
% of Total Operations & Maintenance /Govenance and Support Services EFTs											31%

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
PUB/MH-II-1a (i): 100% of the losses reduced, 100% covered by OM&A reductions
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	2 008	2 101	2 222	2 352	2 732	2 944	3 054	3 182
EXPENSES										
Operating and Administrative	486	523	511	493	479	463	447	418	393	363
Finance Expense	495	510	545	577	743	871	1 168	1 289	1 284	1 283
Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	145	146	153	154	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 804	1 914	1 975	2 217	2 333	2 742	2 927	2 966	2 969
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	135	102	133	11	23	(0)	17	86	210
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	18%	17%	16%	15%	15%	14%	14%	14%	15%
Interest Coverage	1.16	1.19	1.12	1.13	1.01	1.02	1.00	1.01	1.07	1.16
Capital Coverage	0.98	1.05	1.01	1.22	1.07	1.06	1.13	1.34	1.57	1.80

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
PUB/MH-II-1a (i): 100% of the losses reduced, 100% covered by OM&A reductions
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	1 551	1 565	1 580	1 593	1 607	1 624	1 641	1 659	1 677	1 696
additional*	734	832	935	1 043	1 157	1 280	1 409	1 486	1 566	1 649
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3 298	3 342	3 475	3 575	3 702	3 849	3 980	4 065	4 145	4 248
EXPENSES										
Operating and Administrative	411	461	516	574	636	699	769	785	801	817
Finance Expense	1 264	1 243	1 214	1 201	1 175	1 146	1 104	1 033	994	945
Depreciation and Amortization	767	780	791	804	811	820	831	842	857	873
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	162	163	164	165	166	167	169	170	173	174
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3 025	3 065	3 111	3 171	3 224	3 277	3 322	3 291	3 288	3 287
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	268	276	361	399	472	562	646	759	840	943
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.31%	53.13%	59.18%	65.47%	72.01%	78.80%	85.86%	89.58%	93.37%	97.24%
Financial Ratios										
Equity	16%	17%	19%	21%	23%	25%	28%	31%	34%	38%
Interest Coverage	1.21	1.22	1.29	1.33	1.39	1.48	1.57	1.72	1.82	1.96
Capital Coverage	1.77	1.79	1.91	1.95	2.00	2.18	2.19	2.35	2.45	2.57

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
PUB/MH-II-1a (i): 100% of the losses reduced, 100% covered by OM&A reductions
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 294	2 596	2 726	2 167	2 285	2 432
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 800	24 961	26 584	27 666	28 298	27 727	27 835	27 955
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 481	18 489	20 977	21 506	22 192	22 155	22 450	22 241
Current and Other Liabilities	2 016	2 131	2 234	3 138	2 181	2 682	2 655	2 134	1 831	1 913
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 798	2 900	3 032	3 043	3 066	3 066	3 083	3 169	3 379
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 800	24 961	26 584	27 666	28 298	27 727	27 835	27 955

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
PUB/MH-II-1a (i): 100% of the losses reduced, 100% covered by OM&A reductions
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823	42 952
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 384)	(17 200)	(18 031)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 710	24 666	24 623	24 921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 373	2 519	2 868	3 299	3 734	4 248	4 213	4 985	5 774	6 631
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27 901	28 045	28 383	28 783	29 197	29 666	29 615	30 372	31 178	32 118
LIABILITIES AND EQUITY										
Long-Term Debt	21 795	21 998	22 201	22 143	22 076	21 349	21 339	21 343	21 337	20 981
Current and Other Liabilities	1 999	1 626	1 364	1 386	1 359	1 955	1 230	1 186	1 119	1 433
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	3 647	3 922	4 283	4 681	5 153	5 714	6 359	7 118	7 957	8 899
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 901	28 045	28 383	28 783	29 197	29 666	29 615	30 372	31 178	32 118

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
PUB/MH-II-1a (i): 100% of the losses reduced, 100% covered by OM&A reductions
(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	2 039	2 134	2 231	2 349	2 729	2 941	3 051	3 180
Cash Paid to Suppliers and Employees	(803)	(852)	(902)	(909)	(908)	(893)	(916)	(912)	(901)	(887)
Interest Paid	(511)	(514)	(543)	(588)	(774)	(912)	(1 199)	(1 313)	(1 279)	(1 279)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	606	616	668	584	579	645	744	886	1 030
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	2 990	3 200	2 790	1 400	1 390	400	560	180
Sinking Fund Withdrawals	110	21	-	7	448	203	291	715	165	19
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 636	2 857	2 013	1 269	730	372	243	(123)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(240)	(243)	(261)	(358)	(244)	(249)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 514)	(1 828)	(1 301)	(1 144)	(973)	(976)
Net Increase (Decrease) in Cash	(270)	(58)	(71)	17	82	20	74	(28)	156	(69)
Cash at Beginning of Year	133	(137)	(195)	(266)	(250)	(167)	(148)	(73)	(101)	55
Cash at End of Year	(137)	(195)	(266)	(250)	(167)	(148)	(73)	(101)	55	(14)

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
PUB/MH-II-1a (i): 100% of the losses reduced, 100% covered by OM&A reductions
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 295	3 340	3 472	3 572	3 699	3 846	3 977	4 062	4 142	4 245
Cash Paid to Suppliers and Employees	(946)	(994)	(1 057)	(1 116)	(1 187)	(1 262)	(1 338)	(1 365)	(1 387)	(1 417)
Interest Paid	(1 267)	(1 249)	(1 229)	(1 234)	(1 223)	(1 201)	(1 175)	(1 080)	(1 054)	(1 018)
Interest Received	19	21	34	47	59	67	78	56	69	82
	1 101	1 118	1 220	1 268	1 348	1 450	1 542	1 673	1 770	1 892
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	(10)	180	190	(10)	(20)	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	287	89	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	(156)	(211)	161	(37)	(45)	(22)	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(257)	(252)	(257)	(268)	(278)	(286)	(292)	(268)	(278)	(288)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 031)	(1 034)	(1 035)	(1 039)	(1 066)	(1 060)	(1 105)	(1 095)	(1 151)	(1 243)
Net Increase (Decrease) in Cash	(86)	(127)	346	193	237	369	395	520	572	604
Cash at Beginning of Year	(14)	(100)	(227)	119	312	549	918	1 313	1 833	2 405
Cash at End of Year	(100)	(227)	119	312	549	918	1 313	1 833	2 405	3 009

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
PUB/MH-II-1a (ii): 100% of the losses reduced, 100% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	77	159	248	342	442	547	659	781	910
BPIII Reserve Account	(30)	(33)	(35)	(37)	(12)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 947	2 048	2 165	2 314	2 473	2 885	3 132	3 280	3 451
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	545	577	743	871	1 168	1 289	1 284	1 283
Depreciation and Amortization	405	401	422	445	521	523	612	665	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	145	146	153	154	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	1 954	2 040	2 308	2 454	2 895	3 115	3 193	3 237
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	135	102	133	11	23	0	17	86	210
* Additional General Consumers Revenue										
Percent Increase	0.00%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%
Cumulative Percent Increase	0.00%	5.30%	10.88%	16.76%	22.95%	29.47%	36.33%	43.55%	51.16%	59.18%
Financial Ratios										
Equity	22%	18%	17%	16%	15%	15%	14%	14%	14%	15%
Interest Coverage	1.16	1.19	1.12	1.13	1.01	1.02	1.00	1.01	1.07	1.16
Capital Coverage	0.98	1.05	1.01	1.22	1.07	1.06	1.12	1.34	1.58	1.80

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
PUB/MH-II-1a (ii): 100% of the losses reduced, 100% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	1 551	1 565	1 580	1 593	1 607	1 624	1 641	1 659	1 677	1 696
additional*	967	1 027	1 089	1 152	1 217	1 287	1 360	1 435	1 513	1 595
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3 531	3 538	3 629	3 684	3 762	3 856	3 930	4 014	4 093	4 194
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 264	1 243	1 214	1 201	1 175	1 146	1 104	1 033	994	945
Depreciation and Amortization	767	780	791	804	811	820	831	842	857	873
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	162	163	164	165	166	167	169	170	173	174
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3 258	3 260	3 265	3 280	3 284	3 285	3 272	3 240	3 236	3 232
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	268	276	361	399	472	562	646	759	840	943
* Additional General Consumers Revenue										
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	62.36%	65.61%	68.92%	72.30%	75.74%	79.26%	82.84%	86.50%	90.23%	94.04%
Financial Ratios										
Equity	16%	17%	19%	21%	23%	25%	28%	31%	34%	38%
Interest Coverage	1.21	1.22	1.29	1.33	1.39	1.48	1.57	1.72	1.82	1.96
Capital Coverage	1.77	1.79	1.91	1.96	2.00	2.18	2.19	2.35	2.45	2.57

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
PUB/MH-II-1a (ii): 100% of the losses reduced, 100% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 294	2 596	2 726	2 167	2 286	2 432
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 800	24 961	26 584	27 666	28 298	27 727	27 836	27 955
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 481	18 489	20 977	21 506	22 192	22 155	22 450	22 241
Current and Other Liabilities	2 016	2 131	2 233	3 136	2 178	2 679	2 653	2 133	1 831	1 912
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	82	116	153	165	110	55	-	-	-
Retained Earnings	2 717	2 798	2 900	3 032	3 044	3 066	3 066	3 083	3 170	3 380
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 800	24 961	26 584	27 666	28 298	27 727	27 836	27 955

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
PUB/MH-II-1a (ii): 100% of the losses reduced, 100% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823	42 952
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 384)	(17 200)	(18 031)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 710	24 666	24 623	24 921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 373	2 519	2 868	3 300	3 735	4 249	4 214	4 986	5 775	6 632
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27 901	28 045	28 384	28 784	29 198	29 667	29 616	30 373	31 179	32 119
LIABILITIES AND EQUITY										
Long-Term Debt	21 795	21 998	22 201	22 143	22 076	21 349	21 339	21 343	21 337	20 981
Current and Other Liabilities	1 998	1 626	1 364	1 386	1 359	1 955	1 230	1 186	1 119	1 433
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	3 648	3 923	4 284	4 682	5 153	5 715	6 360	7 119	7 958	8 900
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 901	28 045	28 384	28 784	29 198	29 667	29 616	30 373	31 179	32 119

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
PUB/MH-II-1a (ii): 100% of the losses reduced, 100% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 977	2 080	2 200	2 323	2 470	2 882	3 129	3 278	3 448
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 070)	(1 101)	(1 127)	(1 155)
Interest Paid	(511)	(514)	(543)	(588)	(774)	(912)	(1 199)	(1 313)	(1 279)	(1 279)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	607	616	670	585	578	644	743	886	1 030
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	2 990	3 200	2 790	1 400	1 390	400	560	180
Sinking Fund Withdrawals	110	21	-	7	448	203	291	715	165	19
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 636	2 857	2 013	1 269	730	372	243	(123)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(240)	(243)	(261)	(358)	(244)	(249)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 514)	(1 828)	(1 301)	(1 144)	(973)	(976)
Net Increase (Decrease) in Cash	(270)	(58)	(70)	18	83	19	73	(29)	157	(69)
Cash at Beginning of Year	133	(137)	(195)	(265)	(247)	(164)	(145)	(72)	(101)	56
Cash at End of Year	(137)	(195)	(265)	(247)	(164)	(145)	(72)	(101)	56	(13)

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
PUB/MH-II-1a (ii): 100% of the losses reduced, 100% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 528	3 535	3 626	3 681	3 759	3 853	3 927	4 011	4 089	4 190
Cash Paid to Suppliers and Employees	(1 179)	(1 189)	(1 211)	(1 225)	(1 247)	(1 269)	(1 288)	(1 314)	(1 334)	(1 363)
Interest Paid	(1 267)	(1 249)	(1 229)	(1 234)	(1 222)	(1 201)	(1 175)	(1 079)	(1 054)	(1 018)
Interest Received	19	21	34	47	59	67	78	56	69	82
	1 101	1 118	1 220	1 268	1 348	1 450	1 542	1 673	1 770	1 892
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	(10)	180	190	(10)	(20)	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	287	89	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	(156)	(211)	161	(37)	(45)	(22)	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(257)	(252)	(257)	(268)	(278)	(286)	(292)	(268)	(278)	(288)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 031)	(1 034)	(1 035)	(1 039)	(1 066)	(1 060)	(1 105)	(1 095)	(1 151)	(1 243)
Net Increase (Decrease) in Cash	(86)	(127)	346	193	237	369	395	520	572	604
Cash at Beginning of Year	(13)	(99)	(226)	120	313	550	919	1 314	1 834	2 406
Cash at End of Year	(99)	(226)	120	313	550	919	1 314	1 834	2 406	3 010

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
PUB/MH-II-1a (iii): 50% of losses reduced, 100% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	65	132	206	283	364	448	537	633	735
BPIII Reserve Account	(30)	(33)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 934	2 022	2 124	2 255	2 394	2 786	3 010	3 133	3 276
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	546	580	748	880	1 184	1 312	1 315	1 325
Depreciation and Amortization	405	401	422	445	521	524	612	666	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	145	152	152	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	1 955	2 042	2 313	2 464	2 911	3 137	3 222	3 279
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	123	75	89	(53)	(66)	(115)	(127)	(90)	(7)
* Additional General Consumers Revenue										
Percent Increase	0.00%	4.44%	4.44%	4.44%	4.44%	4.44%	4.44%	4.44%	4.44%	4.44%
Cumulative Percent Increase	0.00%	4.44%	9.07%	13.91%	18.96%	24.24%	29.75%	35.50%	41.51%	47.79%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	14%	13%	12%	11%	12%
Interest Coverage	1.16	1.17	1.09	1.09	0.95	0.95	0.91	0.90	0.93	0.99
Capital Coverage	0.98	1.03	0.97	1.14	0.94	0.89	0.93	1.08	1.26	1.42

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
PUB/MH-II-1a (iii): 50% of losses reduced, 100% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	1 551	1 565	1 580	1 593	1 607	1 624	1 641	1 659	1 677	1 696
additional*	787	842	898	956	1 015	1 079	1 145	1 214	1 285	1 359
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3 351	3 352	3 438	3 488	3 560	3 648	3 716	3 792	3 865	3 958
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 320	1 313	1 299	1 300	1 289	1 276	1 249	1 192	1 167	1 134
Depreciation and Amortization	767	780	791	804	811	820	831	842	857	873
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	162	163	164	165	166	167	168	170	172	174
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3 315	3 330	3 350	3 379	3 398	3 414	3 417	3 398	3 408	3 421
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	31	21	85	104	156	224	287	379	439	519
* Additional General Consumers Revenue										
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	50.75%	53.76%	56.84%	59.97%	63.17%	66.44%	69.76%	73.16%	76.62%	80.16%
Financial Ratios										
Equity	12%	12%	13%	13%	14%	15%	16%	18%	20%	22%
Interest Coverage	1.02	1.02	1.06	1.08	1.12	1.17	1.22	1.31	1.37	1.44
Capital Coverage	1.40	1.38	1.48	1.51	1.54	1.68	1.68	1.82	1.89	2.00

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
PUB/MH-II-1a (iii): 50% of losses reduced, 100% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 295	2 597	2 726	2 167	2 235	2 438
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 585	27 668	28 298	27 727	27 785	27 962
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 706	22 592	22 555	23 050	23 041
Current and Other Liabilities	2 016	2 144	2 073	3 020	2 128	2 718	2 605	2 228	1 852	2 007
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	152	163	109	54	-	-	-
Retained Earnings	2 717	2 785	2 860	2 949	2 896	2 830	2 715	2 588	2 498	2 491
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 585	27 668	28 298	27 727	27 785	27 962

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
PUB/MH-II-1a (iii): 50% of losses reduced, 100% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823	42 952
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 384)	(17 200)	(18 031)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 710	24 666	24 623	24 921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 382	2 530	2 774	3 030	3 270	3 650	3 256	3 648	4 036	4 470
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27 909	28 057	28 289	28 514	28 733	29 068	28 658	29 035	29 440	29 956
LIABILITIES AND EQUITY										
Long-Term Debt	22 995	23 398	23 601	23 743	23 876	23 349	23 339	23 343	23 337	22 981
Current and Other Liabilities	1 932	1 618	1 527	1 468	1 362	1 962	1 237	1 193	1 126	1 440
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2 523	2 543	2 627	2 730	2 885	3 109	3 395	3 774	4 212	4 730
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 909	28 057	28 289	28 514	28 733	29 068	28 658	29 035	29 440	29 956

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
PUB/MH-II-1a (iii): 50% of losses reduced, 100% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 965	2 054	2 158	2 264	2 392	2 783	3 007	3 130	3 273
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 069)	(1 100)	(1 125)	(1 155)
Interest Paid	(511)	(514)	(543)	(593)	(784)	(923)	(1 211)	(1 336)	(1 311)	(1 321)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	594	590	622	515	488	534	600	710	813
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 400	1 590	400	760	380
Sinking Fund Withdrawals	110	21	-	7	448	204	293	715	165	24
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 269	932	372	443	82
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(244)	(261)	(358)	(249)	(255)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 515)	(1 829)	(1 301)	(1 144)	(978)	(982)
Net Increase (Decrease) in Cash	(270)	(71)	103	(29)	12	(72)	165	(172)	175	(88)
Cash at Beginning of Year	133	(137)	(208)	(105)	(134)	(122)	(193)	(28)	(201)	(26)
Cash at End of Year	(137)	(208)	(105)	(134)	(122)	(193)	(28)	(201)	(26)	(114)

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
PUB/MH-II-1a (iii): 50% of losses reduced, 100% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 348	3 349	3 435	3 485	3 557	3 645	3 713	3 789	3 861	3 955
Cash Paid to Suppliers and Employees	(1 179)	(1 189)	(1 211)	(1 225)	(1 247)	(1 269)	(1 288)	(1 313)	(1 334)	(1 362)
Interest Paid	(1 319)	(1 322)	(1 315)	(1 331)	(1 335)	(1 330)	(1 324)	(1 243)	(1 234)	(1 214)
Interest Received	19	21	35	48	61	70	82	61	75	90
	869	859	944	977	1 036	1 116	1 182	1 294	1 369	1 468
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	390	380	190	190	180	170	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	293	98	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	250	(2)	161	163	155	178	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(266)	(264)	(272)	(284)	(297)	(306)	(315)	(293)	(304)	(314)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 040)	(1 045)	(1 050)	(1 055)	(1 085)	(1 080)	(1 128)	(1 119)	(1 176)	(1 269)
Net Increase (Decrease) in Cash	79	(189)	56	84	106	214	13	116	146	154
Cash at Beginning of Year	(114)	(34)	(223)	(167)	(83)	24	238	251	367	513
Cash at End of Year	(34)	(223)	(167)	(83)	24	238	251	367	513	667

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
PUB/MH-II-1b: 100% of losses reduced, 50% covered by OM&A reductions, 50% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	67	139	216	296	382	471	566	667	775
BPIII Reserve Account	(30)	(33)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 937	2 028	2 134	2 269	2 413	2 809	3 038	3 167	3 316
EXPENSES										
Operating and Administrative	486	532	531	524	525	525	524	513	506	497
Finance Expense	495	510	545	577	742	870	1 168	1 289	1 284	1 283
Depreciation and Amortization	405	401	422	445	521	524	612	666	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	145	146	153	154	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 814	1 933	2 007	2 262	2 394	2 819	3 021	3 079	3 103
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	136	103	134	12	23	0	17	87	210
* Additional General Consumers Revenue										
Percent Increase	0.00%	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%	4.64%
Cumulative Percent Increase	0.00%	4.64%	9.50%	14.58%	19.89%	25.46%	31.28%	37.37%	43.74%	50.41%
Financial Ratios										
Equity	22%	18%	17%	16%	15%	15%	14%	14%	14%	15%
Interest Coverage	1.16	1.19	1.12	1.13	1.01	1.02	1.00	1.01	1.07	1.16
Capital Coverage	0.98	1.05	1.01	1.22	1.07	1.06	1.13	1.34	1.58	1.80

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
PUB/MH-II-1b: 100% of losses reduced, 50% covered by OM&A reductions, 50% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	1 551	1 565	1 580	1 593	1 607	1 624	1 641	1 659	1 677	1 696
additional*	829	884	942	1 001	1 062	1 127	1 194	1 265	1 338	1 413
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3 393	3 395	3 482	3 533	3 607	3 696	3 765	3 843	3 917	4 013
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 266	1 253	1 235	1 230	1 211	1 189	1 155	1 093	1 063	1 023
Depreciation and Amortization	767	780	791	804	811	820	831	842	857	873
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	162	163	164	165	166	167	168	170	173	174
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3 261	3 270	3 286	3 308	3 320	3 328	3 323	3 299	3 304	3 310
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	127	123	193	219	281	359	430	529	596	683
* Additional General Consumers Revenue										
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	53.42%	56.49%	59.62%	62.81%	66.07%	69.39%	72.78%	76.23%	79.76%	83.35%
Financial Ratios										
Equity	16%	16%	17%	18%	19%	21%	23%	25%	28%	30%
Interest Coverage	1.10	1.10	1.15	1.18	1.23	1.30	1.36	1.47	1.55	1.64
Capital Coverage	1.55	1.54	1.65	1.68	1.71	1.87	1.88	2.03	2.11	2.22

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
PUB/MH-II-1b: 100% of losses reduced, 50% covered by OM&A reductions, 50% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 294	2 596	2 726	2 167	2 289	2 432
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 800	24 961	26 584	27 666	28 298	27 727	27 839	27 955
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 481	18 489	20 977	21 506	22 192	22 155	22 450	22 241
Current and Other Liabilities	2 016	2 131	2 232	3 134	2 176	2 677	2 650	2 130	1 831	1 909
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	116	152	163	109	54	-	-	-
Retained Earnings	2 717	2 798	2 901	3 035	3 047	3 070	3 070	3 087	3 173	3 383
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 800	24 961	26 584	27 666	28 298	27 727	27 839	27 955

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
PUB/MH-II-1b: 100% of losses reduced, 50% covered by OM&A reductions, 50% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823	42 952
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 384)	(17 200)	(18 031)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 710	24 666	24 623	24 921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 373	2 520	2 808	3 059	3 304	3 614	3 363	3 905	4 450	5 047
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27 901	28 047	28 323	28 544	28 766	29 032	28 765	29 292	29 853	30 534
LIABILITIES AND EQUITY										
Long-Term Debt	21 995	22 398	22 601	22 543	22 476	21 749	21 739	21 743	21 737	21 381
Current and Other Liabilities	1 936	1 518	1 363	1 385	1 357	1 953	1 228	1 184	1 117	1 431
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	3 510	3 632	3 825	4 043	4 323	4 681	5 110	5 639	6 234	6 917
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 901	28 047	28 323	28 544	28 766	29 032	28 765	29 292	29 853	30 534

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
PUB/MH-II-1b: 100% of losses reduced, 50% covered by OM&A reductions, 50% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 968	2 060	2 167	2 277	2 410	2 806	3 035	3 164	3 313
Cash Paid to Suppliers and Employees	(803)	(861)	(922)	(940)	(954)	(955)	(994)	(1 007)	(1 014)	(1 021)
Interest Paid	(511)	(514)	(543)	(588)	(774)	(911)	(1 199)	(1 312)	(1 279)	(1 279)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	607	617	670	585	579	644	744	887	1 029
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	2 990	3 200	2 790	1 400	1 390	400	560	180
Sinking Fund Withdrawals	110	21	-	7	448	203	291	715	165	19
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 636	2 857	2 013	1 269	730	372	243	(123)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(240)	(243)	(261)	(358)	(244)	(249)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 514)	(1 828)	(1 301)	(1 144)	(973)	(976)
Net Increase (Decrease) in Cash	(270)	(58)	(70)	19	84	19	74	(29)	157	(70)
Cash at Beginning of Year	133	(137)	(195)	(265)	(246)	(162)	(143)	(69)	(97)	59
Cash at End of Year	(137)	(195)	(265)	(246)	(162)	(143)	(69)	(97)	59	(11)

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
PUB/MH-II-1b: 100% of losses reduced, 50% covered by OM&A reductions, 50% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 390	3 392	3 479	3 530	3 604	3 693	3 762	3 840	3 914	4 009
Cash Paid to Suppliers and Employees	(1 179)	(1 189)	(1 211)	(1 225)	(1 247)	(1 269)	(1 288)	(1 314)	(1 334)	(1 362)
Interest Paid	(1 269)	(1 260)	(1 251)	(1 263)	(1 259)	(1 245)	(1 227)	(1 140)	(1 124)	(1 098)
Interest Received	19	21	34	47	59	67	79	57	70	84
	960	964	1 052	1 088	1 157	1 246	1 325	1 443	1 526	1 633
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	190	380	190	(10)	(20)	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	287	89	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	44	(11)	161	(37)	(45)	(22)	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(257)	(253)	(260)	(272)	(282)	(290)	(297)	(273)	(284)	(293)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 031)	(1 035)	(1 038)	(1 043)	(1 071)	(1 064)	(1 110)	(1 100)	(1 156)	(1 248)
Net Increase (Decrease) in Cash	(27)	(83)	175	8	41	161	174	285	323	339
Cash at Beginning of Year	(11)	(37)	(120)	55	64	105	266	440	726	1 049
Cash at End of Year	(37)	(120)	55	64	105	266	440	726	1 049	1 388

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
PUB/MH-II-1c: 50% of losses reduced, 50% covered by OM&A reductions, 50% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	61	125	194	266	342	421	504	594	688
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 931	2 015	2 112	2 239	2 373	2 759	2 977	3 094	3 229
EXPENSES										
Operating and Administrative	486	538	544	545	555	564	574	574	580	585
Finance Expense	495	510	546	580	748	880	1 184	1 312	1 315	1 325
Depreciation and Amortization	405	401	422	445	521	524	612	666	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	145	152	152	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 820	1 948	2 030	2 297	2 443	2 884	3 104	3 183	3 233
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	123	75	89	(53)	(66)	(115)	(127)	(90)	(7)
* Additional General Consumers Revenue										
Percent Increase	0.00%	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%
Cumulative Percent Increase	0.00%	4.19%	8.56%	13.12%	17.86%	22.81%	27.96%	33.33%	38.92%	44.74%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	14%	13%	12%	11%	12%
Interest Coverage	1.16	1.17	1.09	1.09	0.95	0.95	0.91	0.90	0.93	0.99
Capital Coverage	0.98	1.03	0.97	1.14	0.94	0.89	0.93	1.08	1.26	1.42

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
PUB/MH-II-1c: 50% of losses reduced, 50% covered by OM&A reductions, 50% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	1 551	1 565	1 580	1 593	1 607	1 624	1 641	1 659	1 677	1 696
additional*	783	883	989	1 099	1 216	1 342	1 474	1 553	1 635	1 720
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3 347	3 394	3 529	3 631	3 761	3 911	4 045	4 132	4 215	4 320
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 320	1 312	1 296	1 290	1 268	1 241	1 199	1 128	1 087	1 037
Depreciation and Amortization	767	780	791	804	811	820	831	842	857	873
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	162	163	164	165	166	167	168	170	173	174
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3 315	3 329	3 347	3 368	3 377	3 380	3 368	3 334	3 329	3 324
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	27	63	179	258	378	522	665	783	869	977
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%
Cumulative Percent Increase	50.46%	56.40%	62.58%	69.00%	75.68%	82.62%	89.83%	93.63%	97.50%	101.45%
Financial Ratios										
Equity	12%	12%	13%	14%	16%	18%	21%	24%	28%	31%
Interest Coverage	1.02	1.05	1.14	1.20	1.29	1.41	1.54	1.68	1.78	1.91
Capital Coverage	1.39	1.44	1.63	1.74	1.86	2.12	2.22	2.39	2.49	2.62

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
PUB/MH-II-1c: 50% of losses reduced, 50% covered by OM&A reductions, 50% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 295	2 597	2 726	2 167	2 235	2 438
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 585	27 668	28 298	27 727	27 785	27 962
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 706	22 592	22 555	23 050	23 041
Current and Other Liabilities	2 016	2 144	2 073	3 020	2 128	2 718	2 605	2 228	1 852	2 007
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 786	2 861	2 950	2 897	2 831	2 716	2 589	2 498	2 491
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 585	27 668	28 298	27 727	27 785	27 962

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
PUB/MH-II-1c: 50% of losses reduced, 50% covered by OM&A reductions, 50% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823	42 952
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 384)	(17 200)	(18 031)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 710	24 666	24 623	24 921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 382	2 531	2 774	3 029	3 371	3 844	3 829	4 625	5 442	6 334
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27 909	28 057	28 289	28 513	28 834	29 262	29 231	30 011	30 846	31 820
LIABILITIES AND EQUITY										
Long-Term Debt	22 995	23 398	23 601	23 543	23 476	22 749	22 739	22 743	22 737	22 381
Current and Other Liabilities	1 937	1 580	1 395	1 381	1 354	1 950	1 225	1 181	1 114	1 428
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2 518	2 580	2 759	3 017	3 394	3 915	4 580	5 362	6 230	7 206
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 909	28 057	28 289	28 513	28 834	29 262	29 231	30 011	30 846	31 820

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
PUB/MH-II-1c: 50% of losses reduced, 50% covered by OM&A reductions, 50% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 961	2 047	2 146	2 247	2 370	2 756	2 974	3 091	3 226
Cash Paid to Suppliers and Employees	(803)	(868)	(935)	(961)	(983)	(994)	(1 042)	(1 067)	(1 085)	(1 109)
Interest Paid	(511)	(514)	(543)	(593)	(784)	(923)	(1 211)	(1 336)	(1 311)	(1 321)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	594	590	622	515	488	534	600	710	813
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 400	1 590	400	760	380
Sinking Fund Withdrawals	110	21	-	7	448	204	293	715	165	24
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 269	932	372	443	82
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(244)	(261)	(358)	(249)	(255)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 515)	(1 829)	(1 301)	(1 144)	(978)	(982)
Net Increase (Decrease) in Cash	(270)	(71)	103	(29)	12	(72)	165	(172)	175	(88)
Cash at Beginning of Year	133	(137)	(208)	(105)	(134)	(121)	(193)	(28)	(201)	(26)
Cash at End of Year	(137)	(208)	(105)	(134)	(121)	(193)	(28)	(201)	(26)	(114)

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
PUB/MH-II-1c: 50% of losses reduced, 50% covered by OM&A reductions, 50% covered by increasing rates
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 344	3 391	3 526	3 628	3 758	3 908	4 042	4 129	4 211	4 316
Cash Paid to Suppliers and Employees	(1 179)	(1 189)	(1 211)	(1 225)	(1 247)	(1 269)	(1 288)	(1 314)	(1 334)	(1 363)
Interest Paid	(1 319)	(1 322)	(1 312)	(1 324)	(1 317)	(1 299)	(1 274)	(1 178)	(1 153)	(1 116)
Interest Received	19	21	35	48	61	70	81	60	74	88
	864	901	1 038	1 127	1 255	1 410	1 561	1 697	1 799	1 926
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	390	380	190	(10)	(20)	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	293	98	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	250	(2)	161	(37)	(45)	(22)	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(266)	(264)	(271)	(283)	(294)	(302)	(309)	(286)	(297)	(307)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 040)	(1 045)	(1 049)	(1 054)	(1 082)	(1 076)	(1 122)	(1 113)	(1 169)	(1 262)
Net Increase (Decrease) in Cash	75	(147)	150	37	128	312	398	526	583	619
Cash at Beginning of Year	(114)	(39)	(186)	(35)	1	129	441	839	1 365	1 948
Cash at End of Year	(39)	(186)	(35)	1	129	441	839	1 365	1 948	2 567

Section:	Tab 2 Figures 2.14, 2.15, 2.16,2.17	Page No.:	PUB/MH I-2
Topic:	Capital expenditures		
Subtopic:	Cash Flow		
Issue:	Major & Sustaining Capital Expenditures Impact on Revenue Requirement		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please update the graph assuming a 5.3% annual rate increase consistent with PUB/MH I-7 (c).

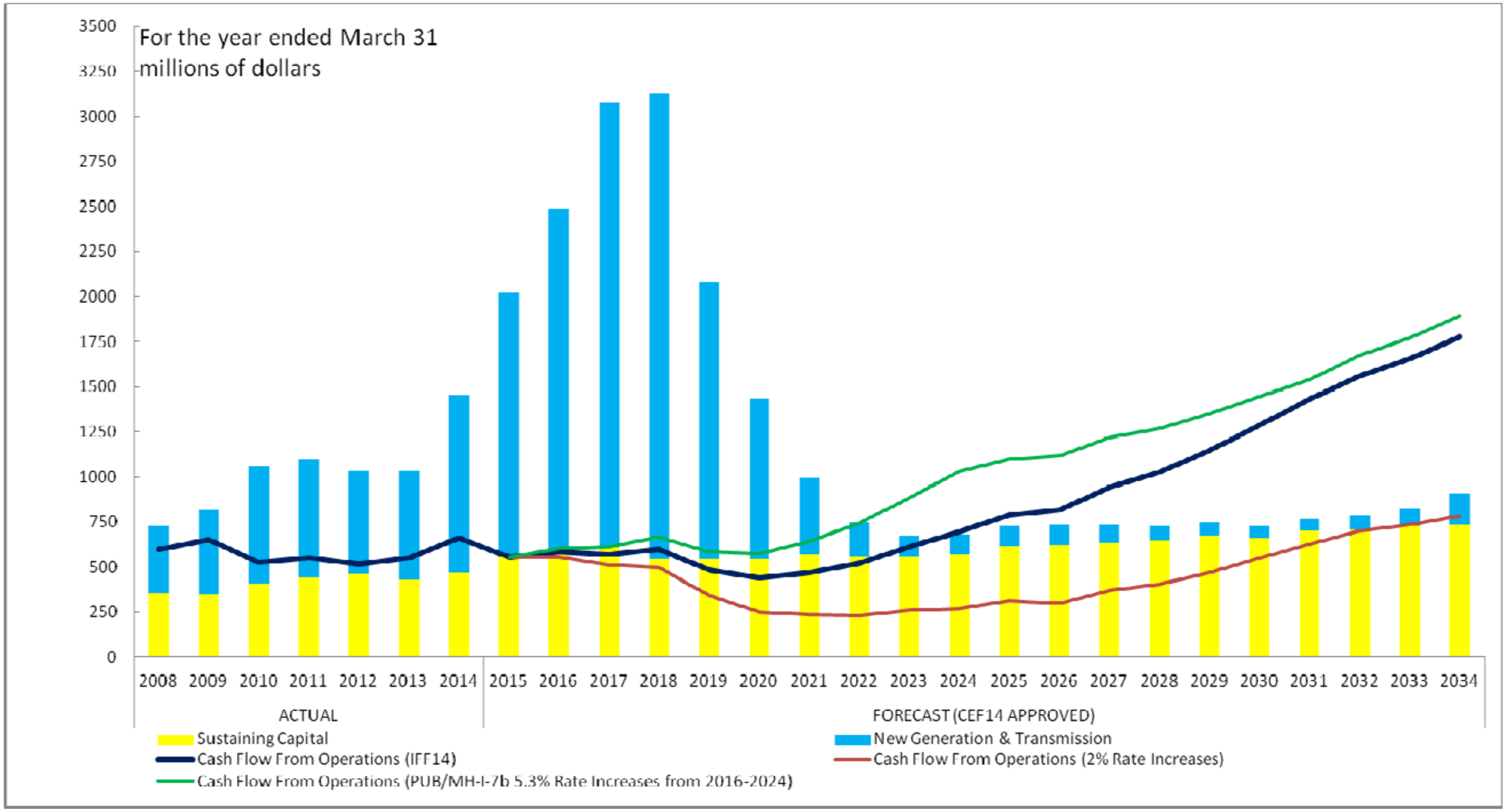
b) Please update the graph consistent with the response to PUB/MH II-1 b and PUB/MH II-1 (c).

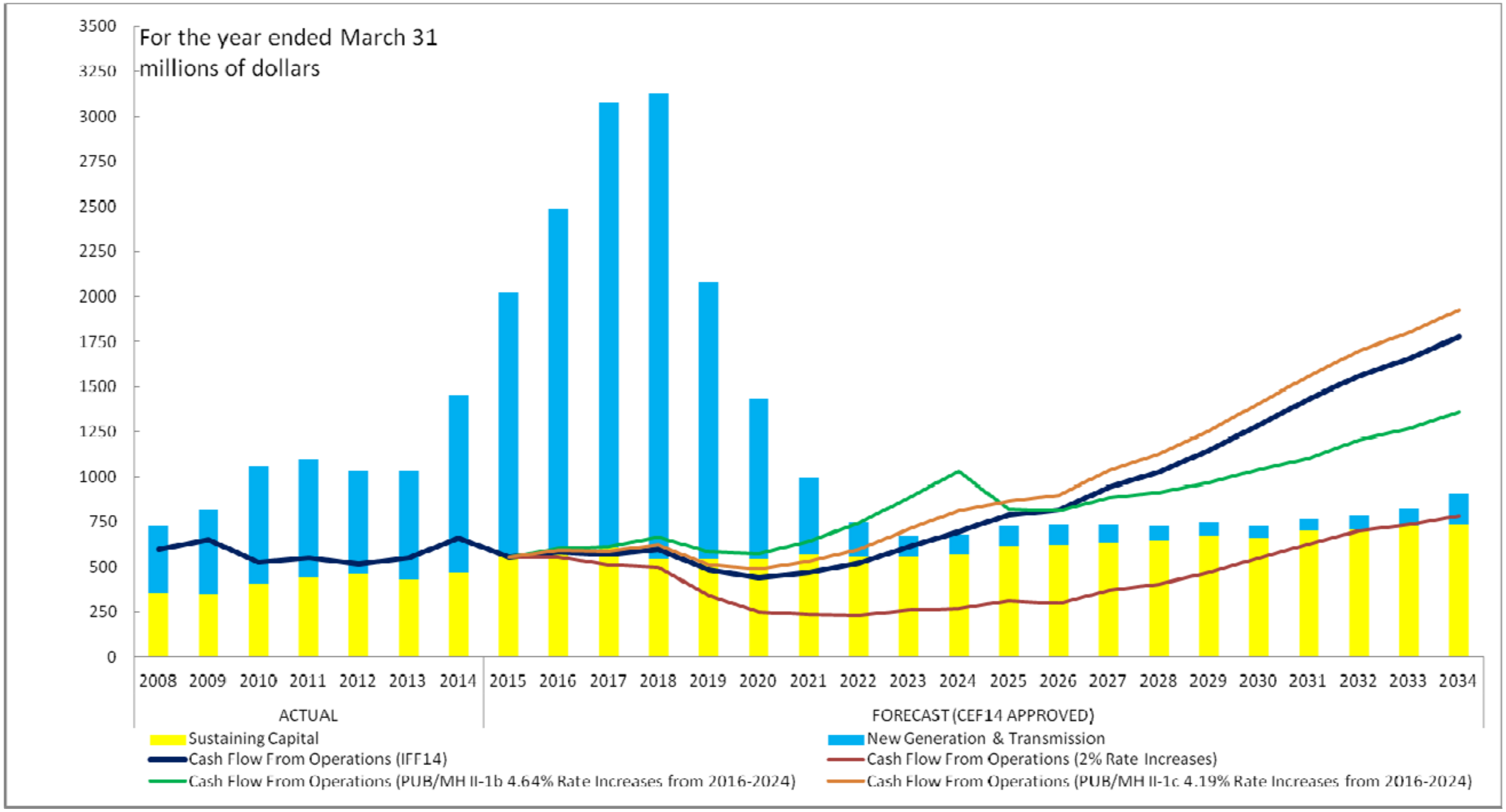
RATIONALE FOR QUESTION:

To assess the changes in capital expenditures and cash flow forecast given historical levels of spending.

RESPONSE:

Please find the updated graphs below.


For the year ended March 31
millions of dollars
3500
3250
3000
2750
2500
2250
2000
1750
1500
1250
1000
750
500
250
0
2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034
ACTUAL
FORECAST (CEF14 APPROVED)
Sustaining Capital
New Generation & Transmission
Cash Flow From Operations (IFF14)
Cash Flow From Operations (2% Rate Increases)
Cash Flow From Operations (PUB/MH-I-7b 5.3% Rate Increases from 2016-2024)


For the year ended March 31
millions of dollars
3500
3250
3000
2750
2500
2250
2000
1750
1500
1250
1000
750
500
250
0
2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034
ACTUAL
FORECAST (CEF14 APPROVED)
Sustaining Capital
New Generation & Transmission
Cash Flow From Operations (IFF14)
Cash Flow From Operations (2% Rate Increases)
Cash Flow From Operations (PUB/MH II-1b 4.64% Rate Increases from 2016-2024)
Cash Flow From Operations (PUB/MH II-1c 4.19% Rate Increases from 2016-2024)

Section:	Tab 2	Page No.:	PUB/MH I-3/ PUB/MH I-4
Topic:	Overview and Reasons for Application		
Subtopic:	Rate Increase		
Issue:	Present Values of GRA Rate Increases		

PREAMBLE TO IR (IF ANY):

In IFF14 restated in PUB/MH I-4 the incremental additional revenue is $35 million in 2015 and $61 million in 2016 for a total of $96 million.

QUESTION:

a) Please provide the NPV analysis based on the updated figure of $61 million for 2016.

b) Please provide the analysis based on $96 million using 2016 as the starting point for the analysis.

RATIONALE FOR QUESTION:

To understand the full financial implications of the proposed 2014/15 and 2015/16 rate increases over the 20 year forecast.

RESPONSE:

a) The incremental additional revenue attributable to the proposed 3.95% rate increase effective April 1, 2015 is $57 million. The incremental additional revenue of $35 million for 2014/15 is the result of the 2.75% rate increase, effective May 1, 2014, for 11 months of the year. The full year impact of the 2.75% rate increase in 2015/16 is $39 million for total additional revenue in 2015/16 of $96 million as shown in the table below.

	2015	2016
General Consumers		
at approved rates	1 401	1 415
additional - 2.75% May 1, 2014 to March 31, 2015	35	-
additional - 2.75% April 1, 2015 to March 31, 2016	-	39
additional - 3.95% April 1, 2015 to March 31, 2016	-	57
Total additional revenue	35	96

The present value of the proposed $57 million additional General Consumers Revenue for 2015/16 is $848 million as shown in PUB/MH-I-3.

b) The attached schedule calculates the present value of the proposed $96 million additional General Consumers Revenue for 2015/16 over the 20 year forecast assuming no further rate increases over the 20 year period to 2033/34. This results in a present value of $1,056 million.

The total discounted additional General Consumers Revenue assuming compounding of future rates increases is $1,423 million.

In Millions of Dollars

				PUB/MH I-4				PUB/MH II-3(b)				PUB/MH II-4 less PUB/MH II-3(b)	
	Nominal WACC	**Discount Factor**	**PUB/MH I-4 General Consumers Revenue**	**Annual Rate Increases**	**Cumulative Rate Increases**	**Additional GCR**	**Discounted Additional GCR**	**Annual Rate Increases**	**Cumulative Rate Increases**	**Additional GCR**	**Discounted Additional GCR**	**Additional GCR**	**Discounted Additional GCR**
2015	6.95%	1.000	1 401	2.75%	2.75%	35	35	2.75%	2.75%	35	35	-	-
2016	6.95%	1.070	1 415	3.95%	6.81%	96	90	3.95%	0.00%	-	-	96	90
2017	6.95%	1.144	1 421	3.95%	11.03%	157	137	3.95%	3.95%	56	49	101	88
2018	6.95%	1.223	1 443	3.95%	15.41%	222	182	3.95%	8.06%	116	95	106	87
2019	6.95%	1.308	1 450	3.95%	19.97%	290	221	3.95%	12.32%	179	137	111	85
2020	6.95%	1.399	1 461	3.95%	24.71%	361	258	3.95%	16.76%	245	175	116	83
2021	6.95%	1.497	1 466	3.95%	29.64%	434	290	3.95%	21.37%	313	209	121	81
2022	6.95%	1.601	1 473	3.95%	34.76%	512	320	3.95%	26.17%	385	241	127	79
2023	6.95%	1.712	1 485	3.95%	40.08%	595	348	3.95%	31.15%	462	270	133	77
2024	6.95%	1.831	1 496	3.95%	45.61%	683	373	3.95%	36.33%	544	297	139	76
2025	6.95%	1.958	1 510	3.95%	51.37%	776	396	3.95%	41.72%	630	322	146	74
2026	6.95%	2.094	1 524	3.95%	57.34%	874	417	3.95%	47.31%	721	344	153	73
2027	6.95%	2.240	1 537	3.95%	63.56%	977	436	3.95%	53.13%	817	365	160	72
2028	6.95%	2.395	1 551	3.95%	70.02%	1 086	453	3.95%	59.18%	918	383	168	70
2029	6.95%	2.562	1 564	3.95%	76.74%	1 200	469	3.95%	65.47%	1 024	400	176	69
2030	6.95%	2.740	1 580	3.95%	83.72%	1 323	483	3.95%	72.01%	1 138	415	185	68
2031	6.95%	2.930	1 597	3.95%	90.97%	1 453	496	3.95%	78.80%	1 259	430	194	66
2032	6.95%	3.134	1 614	2.00%	94.79%	1 530	488	2.00%	82.38%	1 330	424	200	64
2033	6.95%	3.352	1 632	2.00%	98.69%	1 611	481	2.00%	86.02%	1 404	419	207	62
2034	6.95%	3.585	1 650	2.00%	102.66%	1 694	473	2.00%	89.74%	1 481	413	213	59
NPV							**6 846**				**5 423**		**1 423**

In Millions of Dollars

	PUB/MH II-3(b) Assuming No Projected Future Rate Increases				PUB/MH II-3(b) With Compounding due to Projected Future Rate Increases				
	Annual Rate Increases	**Cumulative Rate Increases**	**Additional GCR**	**Discounted Additional GCR**	**Annual Rate Increases per MH14**	**Cumulative Rate Increases per MH14**	**Additional GCR due to Compounding of Future Rate Increases**	**Discounted Additional GCR due to Compounding of Future Rate Increases**	**Total Discounted Additional GCR**
2015	0.00%	0.00%	-	-	0.00%	0.00%	-		
2016	6.81%	6.81%	96	90	0.00%	0.00%	-	-	90
2017	0.00%	6.81%	97	85	3.95%	3.95%	4	3	88
2018	0.00%	6.81%	98	80	3.95%	8.06%	8	6	87
2019	0.00%	6.81%	99	75	3.95%	12.32%	12	9	85
2020	0.00%	6.81%	99	71	3.95%	16.76%	17	12	83
2021	0.00%	6.81%	100	67	3.95%	21.37%	21	14	81
2022	0.00%	6.81%	100	63	3.95%	26.17%	26	16	79
2023	0.00%	6.81%	101	59	3.95%	31.15%	31	18	77
2024	0.00%	6.81%	102	56	3.95%	36.33%	37	20	76
2025	0.00%	6.81%	103	53	3.95%	41.72%	43	22	74
2026	0.00%	6.81%	104	50	3.95%	47.31%	49	23	73
2027	0.00%	6.81%	105	47	3.95%	53.13%	56	25	72
2028	0.00%	6.81%	106	44	3.95%	59.18%	62	26	70
2029	0.00%	6.81%	106	42	3.95%	65.47%	70	27	69
2030	0.00%	6.81%	108	39	3.95%	72.01%	77	28	68
2031	0.00%	6.81%	109	37	3.95%	78.80%	86	29	66
2032	0.00%	6.81%	110	35	2.00%	82.38%	91	29	64
2033	0.00%	6.81%	111	33	2.00%	86.02%	96	29	62
2034	0.00%	6.81%	112	31	2.00%	89.74%	101	28	59
NPV				**1 056**				**367**	**1 423**

Section:	Tab 9, Appendix 11.20 MFR	**Page No.:**	PUB/MH I-6(b)
Topic:	Energy Supply		
Subtopic:	US Export Sales		
Issue:	Diversity contract sales (since 2008)		

PREAMBLE TO IR (IF ANY):

MH is obligated to make summer diversity sales to NSP and GRE, but not winter sales.

QUESTION:

a) Confirm that MH's Permit #35 includes winter diversity sales to GRE at market based prices.
b) Confirm that these sales do not provide any capacity revenue.
c) Indicate the nature of these sales (by quantity, not revenue); % peak/% off-peak.
d) How do these winter sales differ from bilateral opportunity sales?

RATIONALE FOR QUESTION:

This question explores the impact of diversity commitments and opportunities.

RESPONSE:

With respect to a), c) and d), Manitoba Hydro is not in a position to provide the information requested as it is subject to confidentiality provisions requiring the consent of the counterparties.

However, Manitoba Hydro can confirm that nothing has changed in the agreements since the review conducted during the 2014 Needs For and Alternative To hearing.

With respect to b) Manitoba Hydro can confirm that these agreements involve a swap in capacity and as such do not result in any capacity revenue or capacity costs.

Section:	Tab 3, App. 3.4	**Page No.:**	PUB/MH I-12-a Appendix 11.15
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	MH's Revenue Requirement		
Issue:	Major G&T Revenue Requirement		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please update the table indicating the capital cost of each project, and the determination of finance expense.

b) Update the table to include only incremental net export revenue related to the specific projects included in the schedule.

c) Please provide a scenario of the schedule excluding forecast carbon pricing from net export revenue.

RATIONALE FOR QUESTION:

To test the reasonableness of revenue requirement impacts included in the schedule.

RESPONSE:

a) Please see the schedule in Attachment A for the estimated revenue requirement for each project updated to include the capital cost and determination of finance expense.

Finance expense is calculated by applying the average interest rate to the average net capital requirement for each project and then adds the accretion to finance expense on the associated mitigation or development obligations, if applicable.

b) Manitoba Hydro operates an integrated system in which all available resources are operated as required to meet the total of the Manitoba load and export obligations on a least cost basis while observing operational limitations. This means that, at times, certain plants are not run at full capacity in order to reduce costs and maximize value to the system as a whole. Additionally, portions of water rentals and fuel and power purchased are associated with serving domestic load. As such, incremental export revenues related to specific projects are not readily identifiable or measurable due to the integrated nature of the hydro-electric system. When looking at overall revenue requirement, Manitoba Hydro considers extraprovincial revenues in total (not just incremental export revenues) which partially offset the system costs and reduce the revenue required to be recovered from domestic customers.

However, for the purpose of responding to this question, a portion of extraprovincial revenues, net of fuel and power purchased, has been allocated to Keeyask, Wuskwatim and Bipole III based on the percentage of average energy output of the project (or the loss reduction in the case of Bipole III) relative to total system supply. The net extraprovincial revenue allocated to these projects reduces the associated net capital requirement and correspondingly reduces finance expense attributed to these projects.

It was noted in the preparation of this response, there was an error in the in-service information for Bipole III which understated the revenue requirement in Appendix 11.15. This has been corrected for this response and a revised Appendix 11.15 has been filed concurrently with this response.

c) Please see the schedule in Attachment B for the estimated revenue requirement for Keeyask, Wuskwatim and Bipole III assuming the net extraprovincial revenues under the Low Export Price scenario found in Appendix 3.6 (p.20). As noted in PUB/MH-II-31, a separate MH14 scenario assuming no carbon price until 2019/20 is not available, but the Low Export Price scenario assumes no carbon prices (as well as changes in other factors resulting in lower electricity export prices).

ATTACHMENT A- MH14 Net Extraprovincial Revenues

KEEYASK (ISD 2019/20)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Plant in Service, Opening Balance	-	-	-	-	-	-	2 742	6 342	6 335	6 245	6 155	6 064	5 974	5 884	5 794	5 704	5 617	5 527	5 437	5 347
In-Service	-	-	-	-	-	2 748	3 665	83	-	-	-	-	-	-	-	4	-	-	-	-
Depreciation Expense	-	-	-	-	-	(6)	(65)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)
Plant in Service, Closing Balance	-	-	-	-	-	2 742	6 342	6 335	6 245	6 155	6 064	5 974	5 884	5 794	5 704	5 617	5 527	5 437	5 347	5 256
Average Keeyask Energy (GW.h)	-	-	-	-	-	606	3 853	4 425	4 428	4 427	4 412	4 409	4 432	4 417	4 417	4 417	4 426	4 412	4 410	4 413
Total Supply (GW.h)	36 315	35 764	33 691	33 841	33 624	34 071	37 444	38 345	38 389	38 393	38 379	38 211	38 401	38 227	38 281	38 347	38 319	38 287	38 217	38 297
Keeyask % of Total Supply (%)	0%	0%	0%	0%	0%	2%	10%	12%	12%	12%	11%	12%	12%	12%	12%	12%	12%	12%	12%	12%
MH14 Extraprovincial Revenue	409	434	450	457	479	514	817	943	959	987	996	928	944	921	920	927	911	901	883	884
MH14 Fuel & Power Purchased	(134)	(130)	(191)	(202)	(207)	(205)	(234)	(263)	(257)	(267)	(278)	(275)	(283)	(283)	(291)	(302)	(307)	(317)	(320)	(333)
	275	304	259	255	272	309	583	681	701	720	718	653	661	638	629	625	604	584	563	551
Extraprovincial Revenue (Net of F&PP) Attributed to Keeyask	-	-	-	-	-	(5)	(60)	(79)	(81)	(83)	(83)	(75)	(76)	(74)	(73)	(72)	(70)	(67)	(65)	(63)
Net Capital Requirement	-	-	-	-	-	2 737	6 277	6 191	6 020	5 847	5 674	5 508	5 342	5 178	5 015	4 857	4 697	4 539	4 384	4 230
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense on Capital	-	-	-	-	-	80	269	372	360	351	341	330	319	309	299	288	279	257	245	233
Liability Accretion to Finance Expense	-	-	-	-	-	0	4	6	6	6	6	6	6	6	6	6	6	6	6	6
Finance Expense	-	-	-	-	-	81	273	378	365	356	346	336	325	315	305	294	285	263	252	240
OM&A Costs	-	-	-	-	-	5	14	14	14	15	15	15	15	15	15	15	14	15	15	15
Depreciation	-	-	-	-	-	6	65	90	90	90	90	90	90	90	90	90	90	90	90	90
Water Rentals	-	-	-	-	-	2	13	15	15	15	15	15	15	15	15	15	15	15	15	15
Capital Tax	8	12	17	23	28	31	32	32	31	31	30	30	29	29	29	28	28	27	27	26
Extraprovincial Revenue (Net of F&PP) Attributed to Keeyask	-	-	-	-	-	(5)	(60)	(79)	(81)	(83)	(83)	(75)	(76)	(74)	(73)	(72)	(70)	(67)	(65)	(63)
Estimated Revenue Requirement	8	12	17	23	28	119	337	449	435	424	414	410	398	390	381	370	362	343	333	323
Annual Rate Increase/(Decrease)	0.59%	0.22%	0.32%	0.43%	0.30%	5.95%	13.35%	6.00%	-0.89%	-0.76%	-0.68%	-0.37%	-0.80%	-0.56%	-0.62%	-0.75%	-0.58%	-1.16%	-0.66%	-0.70%
Cumulative Rate Increase	0.59%	0.81%	1.14%	1.58%	1.88%	7.94%	22.35%	29.69%	28.53%	27.55%	26.68%	26.21%	25.20%	24.50%	23.73%	22.80%	22.08%	20.67%	19.87%	19.03%

MANITOBA-MINNESOTA TRANSMISSION PROJECT (Formerly Dorsey-U.S. Border New 500 kV Transmission Line)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Plant in Service, Opening Balance	-	-	-	-	-	7	7	346	340	334	328	322	316	311	305	299	293	287	281	276
In-Service	-	-	-	-	7	-	343	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation Expense	-	-	-	-	-	-	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
Plant in Service, Closing Balance/Net Capital Requirement	-	-	-	-	7	7	346	340	334	328	322	316	311	305	299	293	287	281	276	270
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense	-	-	-	-	0	0	11	20	20	20	19	19	18	18	18	17	17	16	15	15
OM&A Costs	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation	-	-	-	-	-	-	5	6	6	6	6	6	6	6	6	6	6	6	6	6
Transmission Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capital Tax	0	0	1	1	1	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1
	0	0	1	1	2	2	17	28	27	27	27	26	26	26	25	25	24	23	23	22

GREAT NORTHERN TRANSMISSION LINE
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Plant in Service, Opening Balance	-	-	-	-	-	-	-	531	518	504	491	477	464	450	437	423	410	396	383	369
In-Service	-	-	-	-	-	-	542	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation Expense	-	-	-	-	-	-	(10)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)
Plant in Service, Closing Balance/Net Capital Requirement	-	-	-	-	-	-	531	518	504	491	477	464	450	437	423	410	396	383	369	355
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense on Capital	-	-	-	-	-	-	16	31	30	29	29	28	27	26	25	24	24	22	21	20
Liability Accretion to Finance Expense	-	-	-	-	-	-	18	17	16	15	14	13	12	11	10	9	8	8	7	6
Finance Expense	-	-	-	-	-	-	34	48	46	44	42	41	39	37	35	34	32	29	27	25
OM&A Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	-	-	-	-	-	-	16	21	21	21	21	21	21	21	21	21	21	21	21	21
Transmission Charges	-	-	-	-	-	-	16	16	15	15	15	15	14	14	13	13	17	17	17	16
Capital Tax	0	0	0	1	2	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2
	0	0	0	1	2	3	68	87	84	82	80	78	76	74	72	69	72	69	66	64
Annual Rate Increase/(Decrease)	0.01%	0.02%	0.05%	0.06%	0.10%	0.07%	5.32%	1.86%	-0.25%	-0.20%	-0.21%	-0.20%	-0.21%	-0.20%	-0.20%	-0.22%	0.07%	-0.31%	-0.22%	-0.22%
Cumulative Rate Increase	0.01%	0.03%	0.08%	0.14%	0.24%	0.31%	5.64%	7.60%	7.33%	7.11%	6.89%	6.68%	6.45%	6.24%	6.03%	5.80%	5.87%	5.55%	5.31%	5.08%

Manitoba Hydro

ATTACHMENT A- MH14 Net Extraprovincial Revenues

WUSKWATIM

(In Millions of Dollars)

For the year ended March 31

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Plant in Service, Opening Balance	**1 655**	1 668	1 641	1 644	1 617	1 589	1 562	1 534	1 507	1 483	1 455	1 428	1 400	1 373	1 345	1 318	1 290	1 262	1 235	1 212
In-Service	40	-	30	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	4	-
Depreciation Expense	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
Plant in Service, Closing Balance/Net Capital Requirement	1 668	1 641	1 644	1 617	1 589	1 562	1 534	1 507	1 483	1 455	1 428	1 400	1 373	1 345	1 318	1 290	1 262	1 235	1 212	1 184
Average Wuskwatim Energy (GW.h)	1 358	1 493	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517
Total Supply (GW.h)	36 315	35 764	33 691	33 841	33 624	34 071	37 444	38 345	38 389	38 393	38 379	38 211	38 401	38 227	38 281	38 347	38 319	38 287	38 217	38 297
Wuskwatim % of Total Supply (%)	4%	4%	5%	4%	5%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
MH14 Extraprovincial Revenue	409	434	450	457	479	514	817	943	959	987	996	928	944	921	920	927	911	901	883	884
MH14 Fuel & Power Purchased	(134)	(130)	(191)	(202)	(207)	(205)	(234)	(263)	(257)	(267)	(278)	(275)	(283)	(283)	(291)	(302)	(307)	(317)	(320)	(333)
	275	304	259	255	272	309	583	681	701	720	718	653	661	638	629	625	604	584	563	551
Extraprovincial Revenue (Net of F&PP) Attributed to Wuskwatim	(10)	(13)	(12)	(11)	(12)	(14)	(24)	(27)	(28)	(28)	(28)	(26)	(26)	(25)	(25)	(25)	(24)	(23)	(22)	(22)
Net Capital Requirement	1 658	1 618	1 610	1 571	1 531	1 490	1 439	1 384	1 333	1 276	1 221	1 167	1 113	1 061	1 008	956	904	854	808	758
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense on Capital	89	89	91	90	89	88	88	87	84	83	81	79	77	76	74	72	71	66	64	62
Liability Accretion to Finance Expense	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1
Finance Expense	91	91	93	92	91	90	90	89	86	84	83	81	79	77	76	73	72	67	65	62
OM&A Costs	13	12	12	12	12	13	13	13	13	13	14	14	14	14	15	11	11	11	11	11
Depreciation	27	27	27	27	27	27	27	27	28	28	28	28	28	28	28	28	28	28	28	28
Water Rentals	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Capital Tax	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7	6	6	6	6	6
Extraprovincial Revenue (Net of F&PP) Attributed to Wuskwatim	(10)	(13)	(12)	(11)	(12)	(14)	(24)	(27)	(28)	(28)	(28)	(26)	(26)	(25)	(25)	(25)	(24)	(23)	(22)	(22)
Estimated Revenue Requirement	133	131	134	134	132	130	120	115	111	109	108	108	106	106	104	99	98	94	92	91
Annual Rate Increase/(Decrease)	9.27%	-0.22%	0.15%	-0.14%	-0.18%	-0.19%	-0.63%	-0.35%	-0.26%	-0.18%	-0.15%	-0.01%	-0.17%	-0.10%	-0.13%	-0.40%	-0.09%	-0.31%	-0.13%	-0.16%
Cumulative Rate Increase	9.27%	9.03%	9.19%	9.04%	8.83%	8.63%	7.94%	7.57%	7.29%	7.10%	6.94%	6.93%	6.74%	6.63%	6.50%	6.07%	5.97%	5.64%	5.50%	5.34%

ATTACHMENT A- MH14 Net Extraprovincial Revenues

BIPOLE III & RIEL STATION
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Plant in Service, Opening Balance	-	444	419	406	471	4 686	4 604	4 509	4 409	4 308	4 208	4 108	4 008	3 908	3 808	3 709	3 610	3 512	3 413	3 315
In-Service	451	(14)	(2)	77	4 285	18	5	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation Expense	(7)	(11)	(12)	(12)	(70)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(99)	(99)	(99)	(99)	(99)	(99)
Plant in Service, Closing Balance	444	419	406	471	4 686	4 604	4 509	4 409	4 308	4 208	4 108	4 008	3 908	3 808	3 709	3 610	3 512	3 413	3 315	3 216
Bipole III Loss Reductions (GW.h)					190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
Total Supply (GW.h)	36 315	35 764	33 691	33 841	33 624	34 071	37 444	38 345	38 389	38 393	38 379	38 211	38 401	38 227	38 281	38 347	38 319	38 287	38 217	38 297
Bipole III % of Total Supply (%)	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MH14 Extraprovincial Revenue	409	434	450	457	479	514	817	943	959	987	996	928	944	921	920	927	911	901	883	884
MH14 Fuel & Power Purchased	(134)	(130)	(191)	(202)	(207)	(205)	(234)	(263)	(257)	(267)	(278)	(275)	(283)	(283)	(291)	(302)	(307)	(317)	(320)	(333)
	275	304	259	255	272	309	583	681	701	720	718	653	661	638	629	625	604	584	563	551
Extraprovincial Revenue (Net of F&PP) Attributed to Bipole III	-	-	-	-	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Net Capital Requirement	444	419	406	471	4 684	4 601	4 502	4 399	4 295	4 192	4 088	3 984	3 881	3 778	3 676	3 574	3 473	3 371	3 270	3 169
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense on Capital	26	25	24	26	150	272	272	266	256	251	245	238	232	225	219	211	206	191	183	174
Liability Accretion to Finance Expense	-	-	-	-	1	1	1	1	0	-	-	-	-	-	-	-	-	-	-	-
Finance Expense	26	25	24	26	151	273	273	266	256	251	245	238	232	225	219	211	206	191	183	174
OM&A Costs	-	-	-	-	8	12	12	12	13	13	13	13	14	14	14	15	15	15	15	16
Depreciation	7	11	12	12	70	100	100	100	100	100	100	100	100	100	99	99	99	99	99	99
Amortization of BPIII Reserve	-	-	-	-	-	(54)	(54)	(54)	-	-	-	-	-	-	-	-	-	-	-	-
Capital Tax	7	11	17	22	23	23	23	23	22	22	21	21	20	20	19	19	18	18	17	17
Extraprovincial Revenue (Net of F&PP) Attributed to Bipole III	-	-	-	-	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Estimated Revenue Requirement	40	47	53	60	251	353	351	344	388	382	376	370	363	356	348	340	335	319	311	303
Annual Rate Increase/(Decrease)	2.78%	0.46%	0.36%	0.39%	12.33%	5.70%	-0.16%	-0.46%	2.20%	-0.47%	-0.50%	-0.50%	-0.53%	-0.50%	-0.57%	-0.57%	-0.46%	-0.95%	-0.58%	-0.59%
Cumulative Rate Increase	2.78%	3.25%	3.63%	4.03%	16.86%	23.52%	23.32%	22.75%	25.45%	24.86%	24.23%	23.61%	22.95%	22.34%	21.65%	20.96%	20.40%	19.25%	18.56%	17.87%

ATTACHMENT A- MH14 Net Extraprovincial Revenues

FINANCING IMPACTS OF THE SUNK COSTS RELATING TO CONAWAPA
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Plant in Service, Opening Balance	-	-	-	389	376	363	350	336	323	310	297	284	270	257	244	231	217	204	191	178
In-Service			397																	
Depreciation Expense			(8)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)
Plant in Service, Closing Balance/Net Capital Requirement	-	-	389	376	363	350	336	323	310	297	284	270	257	244	231	217	204	191	178	165
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense	-	-	11	22	21	21	20	20	19	18	17	16	16	15	14	13	12	11	10	9
Amortization	-	-	8	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	-	-	20	36	35	34	34	33	32	31	30	30	29	28	27	26	26	24	23	23
Annual Rate Increase/(Decrease)	0.00%	0.00%	1.34%	1.04%	-0.06%	-0.06%	-0.03%	-0.06%	-0.08%	-0.06%	-0.07%	-0.07%	-0.07%	-0.06%	-0.06%	-0.07%	-0.06%	-0.09%	-0.07%	-0.07%
Cumulative Rate Increase	0.00%	0.00%	1.34%	2.40%	2.33%	2.27%	2.24%	2.17%	2.09%	2.03%	1.96%	1.89%	1.82%	1.76%	1.69%	1.62%	1.56%	1.46%	1.39%	1.33%

POINTE DU BOIS SPILLWAY
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Plant in Service, Opening Balance	-	473	557	553	545	537	529	520	512	504	496	488	480	472	463	455	447	439	431	423
In-Service	477	91	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation Expense	(4)	(7)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
Plant in Service, Closing Balance/Net Capital Requirement	473	557	553	545	537	529	520	512	504	496	488	480	472	463	455	447	439	431	423	415
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense	14	29	32	32	31	31	31	31	30	30	29	29	28	27	27	26	26	24	23	23
OM&A Costs	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Depreciation	4	7	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Capital Tax	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2
	20	39	42	42	41	41	41	40	40	39	39	38	37	37	36	35	35	33	33	32
Annual Rate Increase/(Decrease)	1.36%	1.28%	0.23%	-0.06%	-0.05%	-0.04%	-0.01%	-0.05%	-0.08%	-0.05%	-0.06%	-0.06%	-0.06%	-0.06%	-0.05%	-0.07%	-0.05%	-0.12%	-0.06%	-0.06%
Cumulative Rate Increase	1.36%	2.65%	2.88%	2.82%	2.77%	2.73%	2.72%	2.67%	2.59%	2.54%	2.48%	2.42%	2.36%	2.31%	2.25%	2.18%	2.13%	2.00%	1.94%	1.88%

ATTACHMENT A- MH14 Net Extraprovincial Revenues

DSM
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Regulatory Asset, Opening Balance	168	188	212	252	295	344	371	389	390	377	361	341	322	303	287	276	271	271	276	283
In-Service	52	59	77	84	94	78	73	61	50	50	48	48	47	47	48	50	52	54	57	59
Depreciation Expense	(32)	(35)	(38)	(41)	(45)	(51)	(55)	(60)	(63)	(65)	(68)	(67)	(66)	(63)	(60)	(55)	(52)	(50)	(49)	(50)
Regulatory Asset, Closing Balance	188	212	252	295	344	371	389	390	377	361	341	322	303	287	276	271	271	276	283	292
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense	11	11	13	16	19	21	23	23	23	22	21	20	18	17	17	16	16	15	15	16
OM&A Costs	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2
Amortization	32	35	38	41	45	51	55	60	63	65	68	67	66	63	60	55	52	50	49	50
Capital Tax	1	1	1	1	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1
Estimated Revenue Requirement	44	49	53	60	66	75	81	86	89	90	91	90	87	83	79	74	71	68	68	69
Annual Rate Increase/(Decrease)	3.07%	0.26%	0.30%	0.34%	0.40%	0.51%	0.40%	0.29%	0.12%	0.05%	0.03%	-0.15%	-0.19%	-0.29%	-0.31%	-0.35%	-0.21%	-0.19%	-0.07%	0.01%
Cumulative Rate Increase	3.07%	3.34%	3.66%	4.01%	4.43%	4.96%	5.38%	5.68%	5.81%	5.86%	5.89%	5.73%	5.53%	5.23%	4.91%	4.54%	4.32%	4.12%	4.05%	4.06%

SUSTAINING CAPITAL
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Plant in Service, Opening Balance	-	578	1 158	1 790	2 332	2 811	3 339	3 854	4 252	4 616	5 073	5 459	5 865	6 416	6 815	7 231	7 601	7 998	8 394	8 776
In-Service	587	604	675	605	561	627	632	532	513	620	565	599	758	622	652	620	661	676	677	993
Depreciation Expense	(8)	(25)	(43)	(63)	(81)	(100)	(117)	(134)	(149)	(163)	(179)	(193)	(206)	(222)	(236)	(251)	(264)	(279)	(295)	(309)
Plant in Service, Closing Balance/Net Capital Requirement	578	1 158	1 790	2 332	2 811	3 339	3 854	4 252	4 616	5 073	5 459	5 865	6 416	6 815	7 231	7 601	7 998	8 394	8 776	9 460
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense	17	50	86	120	150	180	215	242	261	286	311	334	362	389	412	433	456	457	472	494
Depreciation	8	25	43	63	81	100	117	134	149	163	179	193	206	222	236	251	264	279	295	309
Capital Tax	5	8	11	13	16	18	20	22	24	26	28	31	33	35	37	39	41	44	46	48
Estimated Revenue Requirement	31	82	140	196	246	298	352	398	434	475	519	558	601	646	686	723	762	780	813	851
Total Estimated Revenue Requirement	276	360	460	552	802	1 054	1 400	1 581	1 641	1 660	1 683	1 708	1 723	1 745	1 759	1 761	1 785	1 753	1 762	1 777
Annual Rate Increase/(Decrease)	19.21%	4.67%	5.37%	4.39%	12.09%	10.63%	13.37%	5.95%	1.53%	0.19%	0.26%	0.30%	-0.02%	0.22%	-0.06%	-0.46%	0.13%	-1.45%	-0.30%	-0.15%
Cumulative Rate Increase	19.21%	24.78%	31.48%	37.25%	53.85%	70.20%	92.95%	104.43%	107.56%	107.96%	108.50%	109.14%	109.10%	109.55%	109.43%	108.47%	108.74%	105.70%	105.09%	104.79%
IFF14 Annual Rate Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%
IFF14 Cumulative Rate Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%	47.31%	53.13%	59.18%	65.47%	72.01%	78.80%	85.86%	89.58%	93.37%	97.24%

ATTACHMENT B - Low Export Price Scenario Net Extraprovincial Revenues

KEEYASK (ISD 2019/20)

(In Millions of Dollars)

For the year ended March 31	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Plant in Service, Opening Balance	-	-	-	-	-	-	2 742	6 342	6 335	6 245	6 155	6 064	5 974	5 884	5 794	5 704	5 617	5 527	5 437	5 347
In-Service	-	-	-	-	-	2 748	3 665	83	-	-	-	-	-	-	-	4	-	-	-	-
Depreciation Expense	-	-	-	-	-	(6)	(65)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)	(90)
Plant in Service, Closing Balance	-	-	-	-	-	2 742	6 342	6 335	6 245	6 155	6 064	5 974	5 884	5 794	5 704	5 617	5 527	5 437	5 347	5 256
Average Keeyask Energy (GW.h)	-	-	-	-	-	606	3 853	4 425	4 428	4 427	4 412	4 409	4 432	4 417	4 417	4 417	4 426	4 412	4 410	4 413
Total Supply (GW.h)	36 315	35 764	33 691	33 841	33 624	34 071	37 444	38 345	38 389	38 393	38 379	38 211	38 401	38 227	38 281	38 347	38 319	38 287	38 217	38 297
Keeyask % of Total Supply (%)	0%	0%	0%	0%	0%	2%	10%	12%	12%	12%	11%	12%	12%	12%	12%	12%	12%	12%	12%	12%
MH14 Extraprovincial Revenue	409	434	393	404	422	440	693	808	823	841	855	752	755	721	720	726	709	697	685	684
MH14 Fuel & Power Purchased	(134)	(130)	(177)	(188)	(190)	(186)	(214)	(244)	(232)	(238)	(246)	(245)	(249)	(249)	(255)	(263)	(268)	(276)	(282)	(294)
	275	304	215	216	232	254	479	564	590	603	609	507	506	472	465	463	440	421	403	390
Extraprovincial Revenue (Net of F&PP) Attributed to Keeyask	-	-	-	-	-	(5)	(49)	(65)	(68)	(70)	(70)	(59)	(58)	(54)	(54)	(53)	(51)	(49)	(46)	(45)
Net Capital Requirement	-	-	-	-	-	2 738	6 288	6 216	6 058	5 898	5 738	5 589	5 441	5 296	5 152	5 012	4 871	4 732	4 596	4 461
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense on Capital	-	-	-	-	-	80	269	373	362	353	344	334	325	316	307	296	289	268	257	245
Liability Accretion to Finance Expense	-	-	-	-	-	0	4	6	6	6	6	6	6	6	6	6	6	6	6	6
Finance Expense	-	-	-	-	-	81	273	379	367	359	350	340	331	322	313	302	295	274	263	252
OM&A Costs	-	-	-	-	-	5	14	14	14	15	15	15	15	15	15	15	14	15	15	15
Depreciation	-	-	-	-	-	6	65	90	90	90	90	90	90	90	90	90	90	90	90	90
Water Rentals	-	-	-	-	-	2	13	15	15	15	15	15	15	15	15	15	15	15	15	15
Capital Tax	8	12	17	23	28	31	32	32	31	31	30	30	29	29	29	28	28	27	27	26
Extraprovincial Revenue (Net of F&PP) Attributed to Keeyask	-	-	-	-	-	(5)	(49)	(65)	(68)	(70)	(70)	(59)	(58)	(54)	(54)	(53)	(51)	(49)	(46)	(45)
Estimated Revenue Requirement	8	12	17	23	28	120	348	464	450	440	430	431	421	416	408	397	391	372	363	353
Annual Rate Increase/(Decrease)	0.59%	0.22%	0.32%	0.43%	0.30%	6.01%	13.96%	6.15%	-0.89%	-0.68%	-0.70%	-0.12%	-0.69%	-0.45%	-0.58%	-0.72%	-0.52%	-1.14%	-0.64%	-0.67%
Cumulative Rate Increase	0.59%	0.81%	1.14%	1.58%	1.88%	8.01%	23.08%	30.66%	29.49%	28.61%	27.71%	27.56%	26.67%	26.11%	25.37%	24.47%	23.83%	22.42%	21.64%	20.82%

ATTACHMENT B - Low Export Price Scenario Net Extraprovincial Revenues

MANITOBA-MINNESOTA TRANSMISSION PROJECT (Formerly Dorsey-U.S. Border New 500 kV Transmission Line)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Plant in Service, Opening Balance	-	-	-	-	-	7	7	346	340	334	328	322	316	311	305	299	293	287	281	276
In-Service	-	-	-	-	7	-	343	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation Expense	-	-	-	-	-	-	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
Plant in Service, Closing Balance/Net Capital Requirement	-	-	-	-	7	7	346	340	334	328	322	316	311	305	299	293	287	281	276	270
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense	-	-	-	-	0	0	11	20	20	20	19	19	18	18	18	17	17	16	15	15
OM&A Costs	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation	-	-	-	-	-	-	5	6	6	6	6	6	6	6	6	6	6	6	6	6
Transmission Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capital Tax	0	0	1	1	1	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1
	0	0	1	1	2	2	17	28	27	27	27	26	26	26	25	25	24	23	23	22

GREAT NORTHERN TRANSMISSION LINE
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Plant in Service, Opening Balance	-	-	-	-	-	-	-	531	518	504	491	477	464	450	437	423	410	396	383	369
In-Service	-	-	-	-	-	-	542	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation Expense	-	-	-	-	-	-	(10)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)
Plant in Service, Closing Balance/Net Capital Requirement	-	-	-	-	-	-	531	518	504	491	477	464	450	437	423	410	396	383	369	355
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense on Capital	-	-	-	-	-	-	16	31	30	29	29	28	27	26	25	24	24	22	21	20
Liability Accretion to Finance Expense	-	-	-	-	-	-	18	17	16	15	14	13	12	11	10	9	8	8	7	6
Finance Expense	-	-	-	-	-	-	34	48	46	44	42	41	39	37	35	34	32	29	27	25
OM&A Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	-	-	-	-	-	-	16	21	21	21	21	21	21	21	21	21	21	21	21	21
Transmission Charges	-	-	-	-	-	-	16	16	15	15	15	15	14	14	13	13	17	17	17	16
Capital Tax	0	0	0	1	2	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2
	0	0	0	1	2	3	68	87	84	82	80	78	76	74	72	69	72	69	66	64
Annual Rate Increase/(Decrease)	0.01%	0.02%	0.05%	0.06%	0.10%	0.07%	5.32%	1.86%	-0.25%	-0.20%	-0.21%	-0.20%	-0.21%	-0.20%	-0.20%	-0.22%	0.07%	-0.31%	-0.22%	-0.22%
Cumulative Rate Increase	0.01%	0.03%	0.08%	0.14%	0.24%	0.31%	5.64%	7.60%	7.33%	7.11%	6.89%	6.68%	6.45%	6.24%	6.03%	5.80%	5.87%	5.55%	5.31%	5.08%

Manitoba Hydro

Manitoba Hydro 2014/15 & 2015/16 General Rate Application
PUB/MH-II-5a-c
ATTACHMENT B - Low Export Price Scenario Net Extraprovincial Revenues

WUSKWATIM

(In Millions of Dollars)

For the year ended March 31

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Plant in Service, Opening Balance	**1 655**	1 668	1 641	1 644	1 617	1 589	1 562	1 534	1 507	1 483	1 455	1 428	1 400	1 373	1 345	1 318	1 290	1 262	1 235	1 212
In-Service	40	-	30	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	4	-
Depreciation Expense	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
Plant in Service, Closing Balance/Net Capital Requirement	1 668	1 641	1 644	1 617	1 589	1 562	1 534	1 507	1 483	1 455	1 428	1 400	1 373	1 345	1 318	1 290	1 262	1 235	1 212	1 184
Average Wuskwatim Energy (GW.h)	1 358	1 493	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517	1 517
Total Supply (GW.h)	36 315	35 764	33 691	33 841	33 624	34 071	37 444	38 345	38 389	38 393	38 379	38 211	38 401	38 227	38 281	38 347	38 319	38 287	38 217	38 297
Wuskwatim % of Total Supply (%)	4%	4%	5%	4%	5%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
MH14 Extraprovincial Revenue	409	434	393	404	422	440	693	808	823	841	855	752	755	721	720	726	709	697	685	684
MH14 Fuel & Power Purchased	(134)	(130)	(177)	(188)	(190)	(186)	(214)	(244)	(232)	(238)	(246)	(245)	(249)	(249)	(255)	(263)	(268)	(276)	(282)	(294)
	275	304	215	216	232	254	479	564	590	603	609	507	506	472	465	463	440	421	403	390
Extraprovincial Revenue (Net of F&PP) Attributed to Wuskwatim	(10)	(13)	(10)	(10)	(10)	(11)	(19)	(22)	(23)	(24)	(24)	(20)	(20)	(19)	(18)	(18)	(17)	(17)	(16)	(15)
Net Capital Requirement	1 658	1 618	1 612	1 575	1 537	1 498	1 451	1 401	1 354	1 302	1 251	1 203	1 155	1 109	1 063	1 017	972	928	889	846
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense on Capital	89	89	91	90	89	88	89	87	85	83	82	80	79	77	76	74	73	68	66	64
Liability Accretion to Finance Expense	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1
Finance Expense	91	91	93	92	91	91	91	89	87	85	84	82	80	79	77	75	74	69	67	65
OM&A Costs	13	12	12	12	12	13	13	13	13	13	14	14	14	14	15	11	11	11	11	11
Depreciation	27	27	27	27	27	27	27	27	28	28	28	28	28	28	28	28	28	28	28	28
Water Rentals	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Capital Tax	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7	6	6	6	6	6
Extraprovincial Revenue (Net of F&PP) Attributed to Wuskwatim	(10)	(13)	(10)	(10)	(10)	(11)	(19)	(22)	(23)	(24)	(24)	(20)	(20)	(19)	(18)	(18)	(17)	(17)	(16)	(15)
Estimated Revenue Requirement	133	131	136	136	134	132	124	120	116	115	113	115	114	114	113	107	107	102	101	99
Annual Rate Increase/(Decrease)	9.27%	-0.22%	0.27%	-0.15%	-0.18%	-0.14%	-0.52%	-0.31%	-0.27%	-0.16%	-0.16%	0.08%	-0.15%	-0.07%	-0.12%	-0.39%	-0.08%	-0.31%	-0.13%	-0.15%
Cumulative Rate Increase	9.27%	9.03%	9.33%	9.16%	8.96%	8.81%	8.25%	7.91%	7.62%	7.45%	7.27%	7.37%	7.21%	7.13%	7.00%	6.58%	6.49%	6.16%	6.02%	5.85%

ATTACHMENT B - Low Export Price Scenario Net Extraprovincial Revenues

BIPOLE III & RIEL STATION

(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Plant in Service, Opening Balance	-	444	419	406	471	4 686	4 604	4 509	4 409	4 308	4 208	4 108	4 008	3 908	3 808	3 709	3 610	3 512	3 413	3 315
In-Service	451	(14)	(2)	77	4 285	18	5	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation Expense	(7)	(11)	(12)	(12)	(70)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(99)	(99)	(99)	(99)	(99)	(99)
Plant in Service, Closing Balance	444	419	406	471	4 686	4 604	4 509	4 409	4 308	4 208	4 108	4 008	3 908	3 808	3 709	3 610	3 512	3 413	3 315	3 216
Bipole III Loss Reductions (GW.h)					190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
Total Supply (GW.h)	36 315	35 764	33 691	33 841	33 624	34 071	37 444	38 345	38 389	38 393	38 379	38 211	38 401	38 227	38 281	38 347	38 319	38 287	38 217	38 297
Bipole III % of Total Supply (%)	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MH14 Extraprovincial Revenue	409	434	393	404	422	440	693	808	823	841	855	752	755	721	720	726	709	697	685	684
MH14 Fuel & Power Purchased	(134)	(130)	(177)	(188)	(190)	(186)	(214)	(244)	(232)	(238)	(246)	(245)	(249)	(249)	(255)	(263)	(268)	(276)	(282)	(294)
	275	304	215	216	232	254	479	564	590	603	609	507	506	472	465	463	440	421	403	390
Extraprovincial Revenue (Net of F&PP) Attributed to Bipole III	-	-	-	-	(1)	(1)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Net Capital Requirement	444	419	406	471	4 684	4 602	4 504	4 401	4 297	4 194	4 091	3 988	3 886	3 783	3 683	3 582	3 481	3 380	3 280	3 179
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense on Capital	26	25	24	26	150	272	272	266	256	251	245	239	232	226	219	212	206	191	183	175
Liability Accretion to Finance Expense	-	-	-	-	1	1	1	1	0	-	-	-	-	-	-	-	-	-	-	-
Finance Expense	26	25	24	26	151	273	273	266	257	251	245	239	232	226	219	212	206	191	183	175
OM&A Costs	-	-	-	-	8	12	12	12	13	13	13	13	14	14	14	15	15	15	15	16
Depreciation	7	11	12	12	70	100	100	100	100	100	100	100	100	100	99	99	99	99	99	99
Amortization of BPIII Reserve	-	-	-	-	-	(54)	(54)	(54)	-	-	-	-	-	-	-	-	-	-	-	-
Capital Tax	7	11	17	22	23	23	23	23	22	22	21	21	20	20	19	19	18	18	17	17
Extraprovincial Revenue (Net of F&PP) Attributed to Bipole III	-	-	-	-	(1)	(1)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Estimated Revenue Requirement	40	47	53	60	251	353	352	345	389	383	377	371	364	357	349	342	336	321	313	304
Annual Rate Increase/(Decrease)	2.78%	0.46%	0.36%	0.39%	12.34%	5.70%	-0.15%	-0.46%	2.20%	-0.47%	-0.50%	-0.49%	-0.53%	-0.49%	-0.57%	-0.57%	-0.46%	-0.95%	-0.58%	-0.59%
Cumulative Rate Increase	2.78%	3.25%	3.63%	4.03%	16.87%	23.54%	23.36%	22.79%	25.49%	24.90%	24.28%	23.67%	23.02%	22.41%	21.72%	21.03%	20.48%	19.33%	18.64%	17.94%

ATTACHMENT B - Low Export Price Scenario Net Extraprovincial Revenues

FINANCING IMPACTS OF THE SUNK COSTS RELATING TO CONAWAPA
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Plant in Service, Opening Balance	-	-	-	389	376	363	350	336	323	310	297	284	270	257	244	231	217	204	191	178
In-Service			397																	
Depreciation Expense			(8)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)
Plant in Service, Closing Balance/Net Capital Requirement	-	-	389	376	363	350	336	323	310	297	284	270	257	244	231	217	204	191	178	165
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense	-	-	11	22	21	21	20	20	19	18	17	16	16	15	14	13	12	11	10	9
Amortization	-	-	8	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	-	-	20	36	35	34	34	33	32	31	30	30	29	28	27	26	26	24	23	23
Annual Rate Increase/(Decrease)	0.00%	0.00%	1.34%	1.04%	-0.06%	-0.06%	-0.03%	-0.06%	-0.08%	-0.06%	-0.07%	-0.07%	-0.07%	-0.06%	-0.06%	-0.07%	-0.06%	-0.09%	-0.07%	-0.07%
Cumulative Rate Increase	0.00%	0.00%	1.34%	2.40%	2.33%	2.27%	2.24%	2.17%	2.09%	2.03%	1.96%	1.89%	1.82%	1.76%	1.69%	1.62%	1.56%	1.46%	1.39%	1.33%

POINTE DU BOIS SPILLWAY
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Plant in Service, Opening Balance	-	473	557	553	545	537	529	520	512	504	496	488	480	472	463	455	447	439	431	423
In-Service	477	91	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation Expense	(4)	(7)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
Plant in Service, Closing Balance/Net Capital Requirement	473	557	553	545	537	529	520	512	504	496	488	480	472	463	455	447	439	431	423	415
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense	14	29	32	32	31	31	31	31	30	30	29	29	28	27	27	26	26	24	23	23
OM&A Costs	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Depreciation	4	7	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Capital Tax	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2
	20	39	42	42	41	41	41	40	40	39	39	38	37	37	36	35	35	33	33	32
Annual Rate Increase/(Decrease)	1.36%	1.28%	0.23%	-0.06%	-0.05%	-0.04%	-0.01%	-0.05%	-0.08%	-0.05%	-0.06%	-0.06%	-0.06%	-0.06%	-0.05%	-0.07%	-0.05%	-0.12%	-0.06%	-0.06%
Cumulative Rate Increase	1.36%	2.65%	2.88%	2.82%	2.77%	2.73%	2.72%	2.67%	2.59%	2.54%	2.48%	2.42%	2.36%	2.31%	2.25%	2.18%	2.13%	2.00%	1.94%	1.88%

ATTACHMENT B - Low Export Price Scenario Net Extraprovincial Revenues

DSM

(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Regulatory Asset, Opening Balance	168	188	212	252	295	344	371	389	390	377	361	341	322	303	287	276	271	271	276	283
In-Service	52	59	77	84	94	78	73	61	50	50	48	48	47	47	48	50	52	54	57	59
Depreciation Expense	(32)	(35)	(38)	(41)	(45)	(51)	(55)	(60)	(63)	(65)	(68)	(67)	(66)	(63)	(60)	(55)	(52)	(50)	(49)	(50)
Regulatory Asset, Closing Balance	188	212	252	295	344	371	389	390	377	361	341	322	303	287	276	271	271	276	283	292
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense	11	11	13	16	19	21	23	23	23	22	21	20	18	17	17	16	16	15	15	16
OM&A Costs	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2
Amortization	32	35	38	41	45	51	55	60	63	65	68	67	66	63	60	55	52	50	49	50
Capital Tax	1	1	1	1	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1
Estimated Revenue Requirement	44	49	53	60	66	75	81	86	89	90	91	90	87	83	79	74	71	68	68	69
Annual Rate Increase/(Decrease)	3.07%	0.26%	0.30%	0.34%	0.40%	0.51%	0.40%	0.29%	0.12%	0.05%	0.03%	-0.15%	-0.19%	-0.29%	-0.31%	-0.35%	-0.21%	-0.19%	-0.07%	0.01%
Cumulative Rate Increase	3.07%	3.34%	3.66%	4.01%	4.43%	4.96%	5.38%	5.68%	5.81%	5.86%	5.89%	5.73%	5.53%	5.23%	4.91%	4.54%	4.32%	4.12%	4.05%	4.06%

SUSTAINING CAPITAL

(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Plant in Service, Opening Balance	-	578	1 158	1 790	2 332	2 811	3 339	3 854	4 252	4 616	5 073	5 459	5 865	6 416	6 815	7 231	7 601	7 998	8 394	8 776
In-Service	587	604	675	605	561	627	632	532	513	620	565	599	758	622	652	620	661	676	677	993
Depreciation Expense	(8)	(25)	(43)	(63)	(81)	(100)	(117)	(134)	(149)	(163)	(179)	(193)	(206)	(222)	(236)	(251)	(264)	(279)	(295)	(309)
Plant in Service, Closing Balance/Net Capital Requirement	578	1 158	1 790	2 332	2 811	3 339	3 854	4 252	4 616	5 073	5 459	5 865	6 416	6 815	7 231	7 601	7 998	8 394	8 776	9 460
Average Interest Rate	5.9%	5.7%	5.8%	5.8%	5.8%	5.9%	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.6%	5.5%	5.4%
Finance Expense	17	50	86	120	150	180	215	242	261	286	311	334	362	389	412	433	456	457	472	494
Depreciation	8	25	43	63	81	100	117	134	149	163	179	193	206	222	236	251	264	279	295	309
Capital Tax	5	8	11	13	16	18	20	22	24	26	28	31	33	35	37	39	41	44	46	48
Estimated Revenue Requirement	31	82	140	196	246	298	352	398	434	475	519	558	601	646	686	723	762	780	813	851
Total Estimated Revenue Requirement	276	360	462	554	805	1 058	1 416	1 601	1 661	1 682	1 705	1 737	1 755	1 780	1 794	1 798	1 823	1 792	1 802	1 818
Annual Rate Increase/(Decrease)	19.21%	4.67%	5.48%	4.37%	12.10%	10.69%	13.82%	6.06%	1.51%	0.25%	0.24%	0.51%	0.06%	0.30%	-0.04%	-0.44%	0.16%	-1.43%	-0.29%	-0.13%
Cumulative Rate Increase	19.21%	24.78%	31.62%	37.37%	53.99%	70.46%	94.02%	105.78%	108.89%	109.41%	109.91%	110.98%	111.10%	111.74%	111.65%	110.73%	111.08%	108.05%	107.45%	107.19%
IFF14 Annual Rate Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%
IFF14 Cumulative Rate Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%	47.31%	53.13%	59.18%	65.47%	72.01%	78.80%	85.86%	89.58%	93.37%	97.24%

Section:	Tab 3: App. 3.3 IFF14 Tab 11.4	**Page No.:**	PUB/MH I-11b/ Appendixes 11.4 & 11.15
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Wuskwatim Power Limited Partnership (WPLP)		
Issue:	Cost impacts to MH Ratepayers of the Amended WPLP Agreement		

PREAMBLE TO IR (IF ANY):

The WPLP IFF 14 includes finance expense of $75 million for 2014/15 and $77 million for 2015/16. Appendix 11.15 indicates finance expense of $95 million for each of the test years.

QUESTION:

a) Please provide the supporting calculation / detail of finance expense for WPLP based on IFF14.

b) Please indicate the amount of capitalized interest on MH's equity contribution to the project.

c) Please indicate what portion of equity contributions to WPLP in the 2013 WPLP Statement of Partners Capital ($219 million from MH and $108 million from TPC) is underwritten by MH debt.

d) Please indicate the finance expense which is not reflected in WPLP IFF14 and provide the calculation for its determination.

RATIONALE FOR QUESTION:

36T

RESPONSE:

a) The attached schedule provides the detailed finance expense calculation for IFF14 WPLP forecast.

b) Manitoba Hydro capitalized $42 million of interest on its equity contributions related to the Wuskwatim project.

c) The total amount of equity contributions as at March 31, 2013, financed by Manitoba Hydro were $311 million ($219 million from MH and $92 million from TPC). As at March 31, 2013, TPC had contributed $16.4 million of their own invested cash.

d) The finance expense associated with Manitoba Hydro's equity contributions to WPLP are not reflected in the IFF14 WPLP forecast. The amount of Manitoba Hydro's finance expense on its WPLP equity contributions is not determined separately from Manitoba Hydro's forecast of finance expense which is based on the consolidated borrowing requirements of the Corporation. Consolidated finance expense is not in practice subsequently allocated to capital or maintenance projects, activities or various functions. However, Appendix 11.15 for Wuskwatim is a representation of the Wuskwatim finance expense attributable to Manitoba Hydro except that it does not consider the interest income accruing on the NCN equity loan or the 33% of finance expense that is attributed to NCN through non-controlling interest. Notwithstanding these exceptions, the difference between the finance expense shown in Appendix 11.15 for Wuskwatim and the IFF14 WPLP forecast of finance expense provides an indication of the amount of finance expense related to Manitoba Hydro's equity contributions to WPLP.

Wuskwatim Power Limited Partnership
Summary of Debt Balances and Finance Expense
($Millions)

For the fiscal years ending March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
[1] Project Debt	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
[2] Long Term Debt	-	-	-	-	-	-	-	-	-	-
Short Term Debt	117	152	178	186	191	181	168	152	142	123
Interconnection Credit Facility	302	301	300	298	297	295	294	292	290	288
Sinking Fund Assets	(10)	(22)	(34)	(48)	(61)	(76)	(91)	(106)	(122)	(138)
Effective Interest Rates:										
WPLP Weighted Average GS Debt Rate	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%
MH Long Term Debt Rate	4.50%	5.10%	5.50%	5.80%	6.00%	6.20%	6.20%	6.20%	6.20%	6.20%
MH Short Term Debt Rate	1.95%	1.30%	2.40%	3.10%	3.45%	3.90%	3.90%	3.90%	3.90%	3.90%
Weighted Average Transmission Debt Rate	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%
MH Sinking Fund Rate	1.30%	1.65%	2.75%	3.45%	3.80%	4.25%	4.25%	4.25%	4.25%	4.25%
WPLP Interest Capitalization Rate	5.37%	5.24%	5.31%	5.38%	5.43%	5.49%	5.50%	5.51%	5.52%	5.53%
[3] Interest on Project Debt	56	56	56	56	56	56	56	56	56	56
[3] Interest on Long Term Debt	-	-	-	-	-	-	-	-	-	-
[3] Interest on Short Term Debt	1	3	5	7	8	8	8	7	7	6
Interest on Interconnection Credit Facility	17	17	17	17	17	17	16	16	16	16
[4] Interest Income	-	(0)	(1)	(1)	(2)	(3)	(3)	(4)	(4)	(5)
Interest Capitalized	(0)	(0)	(1)	-	-	-	-	-	(0)	-

Notes:

[1] Total outstanding advances for 75% of the total capital requirements up to in-service.

[2] Revolving credit facility for additional capital requirements following in-service.

[3] Interest = Average of prior and current year debt balance * nominal interest rate $((1+\text{effective rate})^{1/12}-1)*12$

[4] Interest = Prior year debt balance * nominal interest rate $((1+\text{effective rate})^{1/12}-1)*12$

Wuskwatim Power Limited Partnership
Summary of Debt Balances and Finance Expense
($Millions)

For the fiscal years ending March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1 Project Debt	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
2 Long Term Debt	-	-	-	-	-	-	-	-	-	-
Short Term Debt	97	84	66	43	16	(22)	(67)	(119)	(117)	(118)
Interconnection Credit Facility	286	284	281	279	276	273	270	267	264	261
Sinking Fund Assets	(155)	(172)	(190)	(208)	(227)	(246)	(266)	(286)	(308)	(330)
Effective Interest Rates:										
WPLP Weighted Average GS Debt Rate	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%
MH Long Term Debt Rate	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%
MH Short Term Debt Rate	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%
Weighted Average Transmission Debt Rate	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%
MH Sinking Fund Rate	4.25%	4.25%	5.20%	5.20%	5.20%	5.20%	5.20%	5.20%	5.20%	5.20%
WPLP Interest Capitalization Rate	5.54%	5.55%	5.57%	5.58%	5.60%	5.63%	5.66%	5.71%	5.73%	5.73%
3 Interest on Project Debt	56	56	56	56	56	56	56	56	56	56
3 Interest on Long Term Debt	-	-	-	-	-	-	-	-	-	-
3 Interest on Short Term Debt	5	4	3	2	1	(1)	(2)	(5)	(6)	(6)
Interest on Interconnection Credit Facility	16	16	16	16	15	15	15	15	15	15
4 Interest Income	(6)	(6)	(9)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Interest Capitalized	-	-	-	-	-	-	-	-	(0)	-

Notes:

1 Total outstanding advances for 75% of the total capital requirements up to in-service.

2 Revolving credit facility for additional capital requirements following in-service.

3 Interest = Average of prior and current year debt balance * nominal interest rate ((1+effective rate)$^{1/12}$-1)*12

4 Interest = Prior year debt balance * nominal interest rate ((1+effective rate)$^{1/12}$-1)*12

Section:	Tab 3: App. 3.3 IFF14 Tab 11.4	Page No.:	PUB/MH I-11b/ Appendixes 11.6 & 11.15
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Wuskwatim Power Limited Partnership (WPLP) and Keeyask Hydropower Limited Partnership (KHLP)		
Issue:	Cost impacts to MH Ratepayers of the Amended WPLP Agreement		

PREAMBLE TO IR (IF ANY):

Appendix indicates finance expense of $247 million in 2022 while in Appendix 11.15 finance expense is indicated at $378 million, which is $131 million higher than reflected in the Keeyask IFF 14.

QUESTION:

a) Please provide a detail of Keeyask finance expense for the years 2020 to 2034.

b) Please indicate total finance expense attributable to MH's equity interest being capitalized in each year through 2022.

c) Please indicate what portion of forecast finance expense related to the construction of Keeyask is not being attributed to KHLP.

RATIONALE FOR QUESTION:

36T

RESPONSE:

a) The attached Schedule 1 provides the detailed finance expense calculation for IFF14 KHLP forecast.

b) The attached Schedule 2 provides the finance expense capitalized by Manitoba Hydro related to its equity contributions to the Keeyask project.

c) The finance expense associated with Manitoba Hydro's equity contributions to KHLP are not reflected in the IFF14 KHLP forecast. The amount of Manitoba Hydro's finance expense on its KHLP equity contributions is not determined separately from Manitoba Hydro's forecast of finance expense which is based on the consolidated borrowing requirements of the Corporation. Consolidated finance expense is not in practice subsequently allocated to capital or maintenance projects, activities or various functions. However, the difference between the finance expense shown in Appendix 11.15 for Keeyask and the IFF14 KHLP forecast of finance expense provides an indication of the amount related to Manitoba Hydro's equity contributions to KHLP.

SCHEDULE 1

Keeyask Hydro Power Limited Partnership
Summary of Debt Balances and Finance Expense
($Millions)

For the fiscal years ending March 31	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
[1] Project Debt	4,000	4,200	4,200	4,200	4,354	4,354	4,354	4,354	4,354	4,354	4,354	4,354	4,354	4,354	4,354
[2] Long Term Debt	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Short Term Debt	153	53	120	152	13	22	37	44	44	39	23	(10)	(55)	(307)	(235)
Interconnection Credit Facility	199	201	200	199	198	197	196	194	193	192	190	188	187	185	183
Mitigation Liability	112	113	113	114	114	115	115	116	116	116	118	119	121	122	124
Sinking Fund Assets	-	-	43	87	134	183	235	288	343	401	461	523	588	655	725
Effective Interest Rates:															
Total KHLP Weighted Average GS Debt Rate	5.38%	5.41%	5.41%	5.41%	5.44%	5.44%	5.44%	5.44%	5.44%	5.44%	5.44%	5.44%	5.44%	5.44%	5.44%
MH Long Term Debt Rate	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%
Total MH Short Term Debt Rate	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%
Weighted Average Transmission Debt Rate	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%
Weighted Average Mitigation Liability Debt Rate	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%
MH Sinking Fund Rate	0.00%	0.00%	0.00%	2.68%	3.23%	3.46%	3.59%	4.49%	4.57%	4.62%	4.66%	4.69%	4.71%	4.73%	4.75%
Interest Capitalization Rate	5.28%	5.39%	5.39%	5.39%	5.39%	5.44%	5.44%	5.44%	5.44%	5.44%	5.44%	5.45%	5.46%	5.52%	5.55%
[3] Total Interest on Project Debt	208	225	227	227	227	237	237	237	237	237	237	237	237	237	237
[3] Interest on Long Term Debt	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
[3] Total Interest on Short Term Debt	4	3	4	6	8	1	1	2	2	2	1	0	(1)	(8)	(10)
Interest on Interconnection Credit Facility	3	10	10	10	10	10	10	10	10	9	9	9	9	9	9
Mitigation Liability	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
[4] Interest Income	-	-	-	(2)	(4)	(6)	(8)	(12)	(14)	(17)	(20)	(23)	(26)	(29)	(33)
Interest Capitalized	(201)	(62)	-	-	-	-	-	-	-	-	(0)	-	-	-	-

Notes:

[1] Total outstanding advances for 75% of the total capital requirements up to in-service.

[2] Revolving credit facility for additional capital requirements following in-service.

[3] Interest = Average of prior and current year debt balance * nominal interest rate ((1+effective rate)$^{1/12}$-1)*12

[4] Interest = Prior year debt balance * nominal interest rate ((1+effective rate)$^{1/12}$-1)*12

SCHEDULE 2

Keeyask Hydro Power Limited Partnership
Interest Capitalized on Manitoba Hydro Equity Contributions
($Millions)

For the fiscal years ending March 31	2015	2016	2017	2018	2019	2020	2021	2022
Interest Capitalized on 82.5% of Total Equity	12	23	35	50	67	73	23	-
[1] Accrued Interest on KCN Common Unit Equity Loans During Construction	1	3	6	10	15	19	21	8
Total Interest Capitalized During Construction	13	26	41	61	81	91	44	8

Notes:

[1] At Final Close it is assumed KCN elects the preferred equity option. The interest on the common unit loans is transferred to Manitoba Hydro.

Section:	Tab 3	**Page No.:**	Appendix 11.20
Topic:	Integrated Financial Forecasts		
Subtopic:	MISO Export Contracts		
Issue:	Market Prices for Firm Contract Sales		

PREAMBLE TO IR (IF ANY):

In Appendix 11.20, MH's tabulation of monthly NEB transactions includes Permit No. 379 Firm Summer Sales commencing in June of 2013 and carrying into 2014. This sale previously was reported as Interruptible.

QUESTION:

a) Please advise how these sales are priced, and whether they are based on fixed prices or market prices.

b) If the sales are based on market prices, please explain the rationale for a firm contract that achieves only market prices.

RATIONALE FOR QUESTION:

To understand Manitoba Hydro's export commitments and associated revenues.

RESPONSE:

Please see the response to PUB/MH-II-65a-d.

Section:	Tab 3	Page No.:	
Topic:	Integrated Financial Forecasts & Economic Outlook		
Subtopic:	MISO Export Contracts		
Issue:	Accredited Capacity		

PREAMBLE TO IR (IF ANY):

The terms and conditions of some MISO import contracts may not provide sufficient assurance of Accredited Capacity.

QUESTION:

a) Please file the applicable FERC ruling. If a ruling is not yet available, please file any discussion papers or backgrounders issued by FERC and/or MISO.

b) Provide MH's interpretation of the FERC ruling.

c) Please explain how any redefinition by FERC and/or MISO would affect Manitoba Hydro's priority to serve Domestic Load ahead of exports.

d) Please explain how any redefinition by FERC and/or MISO would affect Manitoba Hydro's export contract obligations and pricing.

RATIONALE FOR QUESTION:

This question explores U.S. regulatory constraints with respect to Manitoba Hydro's firm export commitments.

RESPONSE:

a) Please see the following link for the FERC order regarding the MISO Tariff revision. https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Orders/2014-12-02%20149%20FERC%2061,196%20Docket%20No.%20ER15-35-000.pdf

b) Manitoba Hydro interprets MISO's Tariff revisions to mean that PPAs executed after April 3, 2014 selling Manitoba Hydro system capacity from resources external to MISO will only qualify as Capacity Resources if, under the circumstances of a simultaneous energy emergency, Manitoba Hydro interrupts the energy scheduled under that PPA on a shared basis with the interruption of energy to firm customers in Manitoba.

The specific proportion in which the interruption must be shared will depend on the contractual arrangements in place between MISO and the external supplier's NERC balancing authority, which is Manitoba Hydro Transmission.

PPAs executed on or prior to April 3, 2014 are not impacted by the MISO Tariff revisions.

c) If Manitoba Hydro executes system participation PPAs with purchasers in MISO after April 3, 2014, energy delivered pursuant to those PPAs can only be interrupted during an energy emergency in Manitoba on a shared basis with interruptions to Manitoba load if the MISO region is simultaneously experiencing an energy emergency.

Unless Manitoba Hydro (as balancing authority for Manitoba) amends its Seams Operating Agreement with MISO to add the provisions specified in section 69.A.3.1.c.4 of the MISO Tariff, firm Manitoba load would need to be curtailed pro rata with the energy exported under the new PPA based on the ratio of the PPA schedule to the sum of the Manitoba load plus the PPA schedule.

d) Manitoba Hydro is of the view that the tariff changes will not detract from the quality of Manitoba Hydro's capacity resource. As such the tariff changes will not affect the price Manitoba Hydro expects to be able to negotiate for future PPAs.

Section:	Tab 4; Appendix 11.35 & 11.36	**Page No.:**	PUB/MH I- 17a
Topic:	Capital Expenditures		
Subtopic:	Construction work in progress		
Issue:	Detail of Capital Costs		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update the schedule to include Conawapa.

RATIONALE FOR QUESTION:

This Information Request seeks background information on capital costs.

RESPONSE:

An updated Major New Generation and Transmission Construction Work In Progress schedule ("CWIP"), including Conawapa, is attached.

Please note that in IFF14, it was assumed that the deferred Conawapa costs of $397 million would be transferred out of CWIP into a regulatory deferral account and amortized over a period of 30 years commencing in 2016/17.

Major New Generation and Transmission Construction Work in Progress Continuity Schedule
(in millions of dollars)

		2015			2016			2017		
	Opening Balance	**Net Capital Expenditure**	**In-Service**	**Closing Balance**	**Net Capital Expenditure**	**In-Service**	**Closing Balance**	**Net Capital Expenditure**	**In-Service**	**Closing Balance**
Wuskwatim - Generation	2	41	40	2	13	4	11	15	26	(0)
Keeyask - Generation	917	776	-	1 693	676	-	2 370	962	-	3 331
Grand Rapids Hatchery Upgrade & Expansion	1	2	-	3	5	-	8	9	-	17
Conawapa	301	43	-	344	31	-	376	21	397	(0)
Kelsey Improvements & Upgrades	3	14	17	(0)	9	8	1	13	15	(1)
Kettle Improvements & Upgrades	4	7	6	5	24	24	5	25	24	5
Pointe du Bois Spillway Replacement	403	114	477	40	52	91	0	4	4	0
Pointe du Bois - Transmission	8	16	21	3	17	0	20	14	10	24
Gillam Redevelopment and Expansion Program (GREP)	-	20	18	2	22	24	1	23	24	(0)
Bipole III - Transmission Line	136	203	0	339	360	0	699	381	-	1 080
Bipole III - Converter Stations	301	221	123	399	581	-	979	829	-	1 808
Bipole III - Collector Lines	33	58	4	87	76	-	163	52	13	202
Bipole III - Community Development Initiative	54	2	-	56	2	-	58	2	-	60
Riel 230/500kV Station	287	36	329	(6)	6	0	(0)	-	-	(0)
Manitoba-Minnesota Transmission Project	2	7	-	9	33	-	42	100	-	141
Generating Station Improvements & Upgrades	-	-	-	-	-	-	-	-	-	-
MNG&T Target Adjustment (Cost Flow)	-	(161)	-	(161)	(51)	-	(213)	(61)	-	(274)
TOTAL	**2 452**	**1 400**	**1 036**	**2 810**	**1 855**	**152**	**4 505**	**2 387**	**513**	**6 371**

Major New Generation and Transmission Construction Work in Progress Continuity Schedule
(in millions of dollars)

	2018			2019			2020		
	Net Capital Expenditure	In-Service	Closing Balance	Net Capital Expenditure	In-Service	Closing Balance	Net Capital Expenditure	In-Service	Closing Balance
Wuskwatim - Generation	-	-	(0)	-	-	(0)	-	-	(0)
Keeyask - Generation	1 351	-	4 683	928	-	5 610	618	2 748	3 479
Grand Rapids Hatchery Upgrade & Expansion	7	24	0	-	-	0	-	-	0
Conawapa	-	-	(0)	-	-	(0)	-	-	(0)
Kelsey Improvements & Upgrades	1	1	(0)	-	-	(0)	-	-	(0)
Kettle Improvements & Upgrades	22	26	1	32	32	1	30	30	1
Pointe du Bois Spillway Replacement	(0)	-	0	(0)	-	0	(0)	-	0
Pointe du Bois - Transmission	4	28	0	-	-	0	-	-	0
Gillam Redevelopment and Expansion Program (GREP)	22	22	(1)	20	18	2	19	22	(2)
Bipole III - Transmission Line	494	106	1 468	75	1 487	57	-	-	57
Bipole III - Converter Stations	508	-	2 316	195	2 511	(0)	18	18	(0)
Bipole III - Collector Lines	37	6	233	5	237	0	-	-	0
Bipole III - Community Development Initiative	2	-	62	0	62	0	-	-	0
Riel 230/500kV Station	-	-	(0)	-	-	(0)	-	-	(0)
Manitoba-Minnesota Transmission Project	59	-	201	66	7	259	48	-	308
Generating Station Improvements & Upgrades	-	-	-	-	-	-	3	3	-
MNG&T Target Adjustment (Cost Flow)	(13)	-	(286)	116	-	(170)	72	-	(98)
TOTAL	**2 494**	**212**	**8 646**	**1 437**	**4 353**	**5 723**	**807**	**2 822**	**3 701**

Section:	Tab 4; Appendix 11.35 & 11.36	**Page No.:**	PUB/MH I-17 c
Topic:	Capital Expenditures		
Subtopic:	Construction Work in Progress		
Issue:	Detail of Capital Costs		

PREAMBLE TO IR (IF ANY):

MH commissioned Rashwan Consultant to review Manitoba Hydro's cost estimates of the Bipole III Converter Stations. The Costs of Bipole III have changed since the study was undertaken in 2011.

QUESTION:

Please file the remaining CPJs and addenda with respect to the Bipole III transmission line, collectors and converter stations not provided in response to PUB/MH I-20(e).

RATIONALE FOR QUESTION:

To understand the reasons for the increase in capital costs for Bipole III.

RESPONSE:

All of the CPJs and addendas since the Rashwan Consultant 2011 review have been filed in response to PUB/MH-I-20e.

Section:	Tab 4; Appendix 11.35 & 11.36	**Page No.:**	PUB/MH I-17 c
Topic:	Capital Expenditures		
Subtopic:	Construction Work in Progress		
Issue:	Detail of Capital Costs		

PREAMBLE TO IR (IF ANY):

MH commissioned Rashwan Consultant to review Manitoba Hydro's cost estimates of the Bipole III Converter Stations. The Costs of Bipole III have changed since the study was undertaken in 2011.

QUESTION:

Please file MH Exhibit 102 from the 2010 GRA.

RATIONALE FOR QUESTION:

To understand the reasons for the increase in capital costs for Bipole III.

RESPONSE:

Please find attached to this response MH Exhibit 102 from the 2010/11 & 2011/12 Electric General Rate Application.

Please see Manitoba Hydro's response to PUB/MH-I-20a, which discusses the factors contributing to the increase to the project costs of Bipole III.

Exhibit # MH-102
Transcript Page #4891

Manitoba Hydro Undertaking #107

Manitoba Hydro to examine the possibility of providing the terms and conditions of the retainer for the engineering firm reviewing the cost of BiPole III.

Please refer to the attached correspondence between Rashwan Consultant dated December 22, 2010 and R. B. Brennan dated January 5, 2011.

Manitoba Hydro

R.B. Brennan, FCA
President and
Chief Executive Officer

2011 01 05

Dr. Mohamed Rashwan, P. Eng.
President
TransGrid Solutions
200 - 137 Innovation Drive
Winnipeg, Manitoba
R3T 6B6

Mohamed

Dear Dr. Rashwan:

This will confirm our verbal discussion where I agreed with your December 22, 2010 proposal for the review of the Manitoba Hydro cost estimates of the Bipole III Converter Stations. This proposal includes the hiring of yourself and the other two HVDC experts.

Please proceed as soon as possible. I will arrange for Mr. Ken Adams and his staff to provide you with the information requested in Item #6 of your proposal immediately. My Assistant, Shirley Denesiuk, will be in touch with you shortly to discuss the purchase order arrangements.

All further communications should continue to be coordinated through me. Please accept my very best wishes for a safe, happy and prosperous New Year.

Yours truly,

Bob

RBB/skw

P.O. Box 815 • Winnipeg, Manitoba • CANADA R3C 2P4 • rbbrennan@hydro.mb.ca
Telephone/*N° de téléphone:* (204) 360-3600 • Fax/*N° de télécopieur:* (204) 360-4114

Rashwan Consultant
December 22, 2010

Bipole III HVdc Project

Manitoba Hydro

Attention:

Mr. Bob Brennan

Bipole III Cost Estimate Review

Rashwan Consultant
December 22, 2010

1. Introduction

We are pleased to submit this proposal for the review of the Manitoba Hydro Bipole III converter stations cost estimates. We have put together a team of well qualified individuals to perform the review. Our team is very familiar with HVDC, the present market conditions of converter stations prices, the state of the technology, project implementation and execution.

This proposal is designed as follows:

- The review team
- Review basis
- The scope of work
- Items excluded from the review
- The information and data required from Manitoba Hydro
- Limits of the review
- Schedule
- Price
- Terms of payment

2. Review team

- Mohamed Rashwan
- Dan Lorden (The Energy Initiatives Group EIG)
- Brad Railing (Cross Sound Cable Company LLC)

3. Review basis

For the purpose of this review, the following is assumed:

- Bipole III rating is established at +/- 500 kV and 2000 MW. Therefore no technical discussion will be presented relative to this topic.
- The location of the converter stations is established.
- Any specific technical requirements identified by Manitoba Hydro such as the need for two 12 pulse series connected valve groups per pole and the need for synchronous condensers at Riel will be taken into account. However, the review will not go into why these specific technical requirements have been identified because presumably Manitoba Hydro has done these studies already.
- The length of the HVDC line is approximately 1 364 Km.

4. Scope of work

We have established the scope of work to be as follows:

- Determine if the project description is optimal
- Review of the cost estimates prepared by Manitoba Hydro for Bipole III converter stations located at Riel and Keewatinoow in summer 2010 based on the project description in section 3 above.
- Establish whether the estimates are in line with HVDC industry cost estimates for comparable projects.
- Review the cost estimates for the synchronous condensers
- Assessment of the cash flow making the estimate
- Review if the in service dates of the various components of the system are optimal or whether different strategy of staging the project would be beneficial. In this regard alternatives for staging the project will be presented. However, a detailed analysis of each alternative will not be included because it requires more studies to establish whether a particular staging alternative meets Manitoba Hydro's target use of the project.

5. Items excluded from the review

We have established that the following items are excluded from this present review. Mainly because Manitoba Hydro would have a very good handle on these costs and in some cases such as the environmental assessment and licensing process it is very dependent on the extent and duration.

- The cost of the design, and construction of the HVDC line.
- The costs associated with environmental approvals and consultation with stakeholders.
- Interest and escalation.
- The costs associated with the construction camp in the North.

6. Information and data required from Manitoba Hydro

We have established that the following is the preliminary list of information and data required from Manitoba Hydro. Obviously as we progress with the review, it may be necessary to ask Manitoba Hydro to provide more specific information or clarification regarding a particular budget or cost item.

- The 2010 cost estimates prepared by Manitoba Hydro for the Bipole III converter stations, the synchronous condensers, the electrodes, and any other items that are part of the budget of the converter stations.
- The basis for establishing the cost for each item, meaning what is included in the specific budget item.

- Any assumptions or any specific technical requirements other than our assumptions stated in section 2 "review basis".
- There may be a need for face to face discussions with Manitoba Hydro to understand the reasons behind establishing a specific cost item.

7. Limits of the review

The review does not include any technical review of the requirements of Manitoba Hydro, or the rating and the voltage selection. It will also limit the discussion on any staging alternatives to the presentation of these alternatives but not giving a detailed analysis of each alternative, because it requires more studies to establish whether a particular staging alternative meets Manitoba Hydro's target use of the project.

8. Schedule

We can start the review on Monday January 17th, 2011, provided we receive the required information. A draft report can be ready by Friday February 4th, 2011.

9. Price

We have estimated that the number of man-days for the review process is a maximum 30 man-days (240 man-hours); however, we will invoice Manitoba Hydro only for the number of hours that are used for the review with the limit of 240 hours. The hourly rates for the team members are:

- Mohamed Rashwan 150 $ Canadian
- Dan Lorden 200 $ US
- Brad Railing 200 $ US
-

A fixed US$ exchange rate of 1.05 will be used for billing Manitoba Hydro in Canadian dollars.

If there is any need for Dan Lorden or Brad Railing to travel to Winnipeg, we will seek Manitoba Hydro's approval and all travel costs will be invoiced at cost against the receipts.

10. Terms of payment

The first invoice will be sent to Manitoba Hydro after completion and submission of a draft report for the hours consumed until that moment in time. Any hours

Rashwan Consultant
December 22, 2010

Consumed until the final report is issued will be invoiced by a second invoice. The payments are due in 30 days.

Invoices related to travel will be done separately with the appropriate receipts.

Section:	Tab 4; Appendix 11.35 & 11.36	**Page No.:**	PUB/MH I-17 c
Topic:	Capital Expenditures		
Subtopic:	Construction Work in Progress		
Issue:	Detail of Capital Costs		

PREAMBLE TO IR (IF ANY):

MH commissioned Rashwan Consultant to review Manitoba Hydro's cost estimates of the Bipole III Converter Stations. The Costs of Bipole III have changed since the study was undertaken in 2011.

QUESTION:

Please file a copy of the Rashwan Consultant report.

RATIONALE FOR QUESTION:

To understand the reasons for the increase in capital costs for Bipole III.

RESPONSE:

The information requested contains commercially sensitivity information and has been filed in confidence with the PUB.

Section:	Tab 4; Appendix 11.35 & 11.36	**Page No.:**	PUB/MH I-17 c
Topic:	Capital Expenditures		
Subtopic:	Construction Work in Progress		
Issue:	Detail of Capital Costs		

PREAMBLE TO IR (IF ANY):

MH commissioned Rashwan Consultant to review Manitoba Hydro's cost estimates of the Bipole III Converter Stations. The Costs of Bipole III have changed since the study was undertaken in 2011.

QUESTION:

File MH's response to the findings in the report.

RATIONALE FOR QUESTION:

To understand the reasons for the increase in capital costs for Bipole III.

RESPONSE:

The Key assumptions/findings in the Rashwan report that resulted in the recommended project cost were as follows:

1. The use of historical project costs to form the basis of the Converter Stations Estimate
2. Assumption of an appropriate project contingency at 7.9%

Since the report was filed in 2011, a complete re-estimate has been undertaken on the Bipole III project using Manitoba Hydro's major capital project cost estimating process that was outlined during the NFAT process. During this process the above key assumptions that formed the basis for the Rashwan report were addressed as follows:

1. **Historical Project Costs vs. Awarded Contract Amounts:**

The findings and recommended project cost in the Rashwan report were largely based on historical costs for similar HVDC installation across the world (i.e. not limited to North America). While the use of historical costs is an accepted estimating approach, since 2011 there has been a notable escalation in construction costs across Canada which has impacted the reasonableness of relying on previous historical costs.

The Converter Stations portion of the 2014 Bipole III estimate is largely based on awarded contract values rather than estimated contract amounts based on historical costs. Specifically, the awarded, fixed price contract amount for the HVDC Converter Equipment, the Keewatinohk Camp, Keewatinohk Site Development and the Keewatinohk 230kV AC Switchyard contracts have all been incorporated into the revised 2014 Control Budget. Additionally, the estimated values of any major contracts still to be awarded were updated based on these awarded contract amounts.

2. **The Amount of Project Contingency Included:**

The Rashwan report recommended a project contingency of 7.9% be applied on Bipole III.

Since the Rashwan report was submitted in 2011, Manitoba Hydro has established a detailed risk & contingency process as part of its major capital project cost estimating process. As outlined during the NFAT, and confirmed by Knight Piesold, this risk & contingency process follows industry recognized best practices and is facilitated by a 3rd party risk & contingency expert.

A complete risk and contingency review was conducted as part of establishing the revised 2014 Bipole III Control Budget. The same risk identification and contingency development process applied on the Keeyask project (as presented during the NFAT process) was applied to the Bipole III Project. From this exercise, a revised P50 contingency and Management Reserve fund for Bipole III were developed and included as part of the Control Budget.

Section:	Tab 4, Appendix 4.1	**Page No.:**	PUB/MH I-20
Topic:	Capital Expenditures		
Subtopic:	Bipole III Project Cost		
Issue:	Cost escalation		

PREAMBLE TO IR (IF ANY):

Additional contracts may have been finalized since the last Bipole III cost estimate was provided to the Board.

QUESTION:

a) Provide a breakdown and status of concluded and remaining Bipole III transmission line, collector and converter station procurement and installation contracts in a similar manner to PUB/MH-I-24(a). In addition to filing a redacted version on the public record, file an unredacted version in confidence that indicates the total dollar value of each of the contracts.

b) Provide the detailed cost estimate calculations that support the CEF12 budget estimate of $3.28B and the CEF14 budget estimate of $4.65B.

RATIONALE FOR QUESTION:

The Capital Project Justification (CPJ) sheets lack component cost details.

RESPONSE:

a) The following is a breakdown of the major contracts for Bipole III. Information on contract dollar values is being filed in confidence with the PUB.

Contract	**Status**	**Award Value** *(millions $)*	**Type**	**Escalation**
Riel & Keewatinohk HVDC Converters & Associated Equipment	Awarded. Work Started		Fixed Price	Escalation clause in contract
Riel Synchronous Condensers	Final Negotiations		Fixed Price	Escalation clause in contract
Bipole III - 500kV Transmission Line Construction (segments N2 & S2)	RFP to be Issued		Unit Price	Escalation clause in contract
Bipole III - 500kV Transmission Line Construction (segments N3 & S1)	RFP to be Issued		Unit Price	Escalation clause in contract
Bipole III - 500kV Transmission Line Construction (segments N1 & C2)	RFP to be issued		Unit Price	Escalation clause in contract
Bipole III - 500kV Transmission Line Construction (segments N4 & C1)	RFP to be issued		Unit Price	Escalation clause in contract
Keewatinohk 230kV AC Switchyard	Awarded. Work Started		Fixed Price	Escalation clause in contract
Keewatinohk Construction Camp	Awarded. Work Started		Fixed Price	No Escalation
Bipole III - 500kV Transmission Line Anchors & Foundations (segments N4, C1 & C2)	RFP to be issued		Unit Price	Escalation clause in contract
Keewatinohk Camp Catering, Maintenance, Janitorial & Security	Awarded. Work Started		Unit Price	Escalation clause in contract
Keewatinohk Converter Station Civil Site Development	Awarded. Work Started		Unit Price	Escalation clause in contract
Supply of Bipole III Conductor	Awarded. Work Started		Fixed Price	Escalation clause in contract
Construction of Keewatinohk AC Collector Lines	Awarded. Work Started		Fixed Price	No Escalation
Supply of Bipole III 500kV Transmission Line Steel Towers	Awarded. Work Started		Fixed Price	Escalation clause in contract

For each contract, specific escalation clauses apply which will cause either an increase or a decrease in the actual cost of the work depending on the commodity or labour indices that apply. These indices are driven by the marketplace or specified in the applicable labour agreement. In all cases, contingency has been allocated to address escalation.

b) The CEF 14 budget was developed following the major capital project cost estimating process, which was discussed and reviewed during the NFAT. The estimate development process is a structured approach that builds the estimate from the bottom-up. For the CEF 14 budget a detailed revision of estimate assumptions, incorporation of current market conditions and inclusion of actual bid prices received to-date on the project was conducted.

A more detailed breakdown of the cost items for Bipole III is commercially sensitive and is being filed in confidence with the PUB.

Section:	Tab 4, Appendix 4.1	Page No.:	PUB/MH I-20(e) Attachment 5
Topic:	Capital Expenditures		
Subtopic:	Bipole III Project Cost		
Issue:	Cost escalation		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro considered increasing Bipole III capacity. During the NFAT, Manitoba Hydro also indicated that it may want to split the northern HVDC corridor once Conawapa is in service.

QUESTION:

a) Please indicate whether there have been any changes to the planned integration, operation and configuration of Bipoles I, II and III in light of NFAT recommendations on generation assets.

b) Confirm the currently planned capacity of Bipole III compared to earlier designs.

c) Provide a detailed quantification of all added project components and project costs associated with any increase in planned capacity and configuration changes.

d) To the extent Manitoba Hydro made any decisions to upgrade Bipole III capacity or change the configuration of the northern HVDC system prior to the NFAT, please advise whether Manitoba Hydro has considered reversing that decision as a result of NFAT recommendations. Please summarize Manitoba Hydro's reasons.

RATIONALE FOR QUESTION:

This question explores the capital cost implications of capacity, configuration and operational changes.

RESPONSE:

a) There have been no changes to the planned integration, operation or configuration of Bipoles I, II and III as a result of recommendations from the NFAT process.

b) The Bipole III project includes both the installations of new HVDC converter equipment and associated ac system upgrades. The currently planned capacity of Bipole III remains at 2000MW. The HVDC converter equipment is being designed with a 15% overload capacity. To operate Bipole III as a 2300MW link, it would require further ac collector system upgrades as described in Section 2.3.1, Chapter 2 of the Manitoba Hydro NFAT filing.

c) The increased capacity of the HVDC converter equipment from 2000MW to 2300MW resulted in approximately a $50 million increase to the project's cost. This additional cost is not related to any additional components required, rather it represents the incremental cost to increase the capacity of the already planned (in-scope) HVDC converter equipment.

d) The capacity of Bipole III has not been reconsidered as a result of the NFAT recommendations and remains at 2000MW. The HVDC converter 2300MW rating will ensure sufficient capacity for future generation development, refurbishment of existing generation, and provide flexibility to take advantage of emerging export opportunities. The added cost to provide this HVDC converter capacity (from 2000MW to 2300MW) is marginal in comparison to the costs that would be incurred to add this capacity at a later date. Adding HVDC converter capacity at a later date would require the replacement of a substantial amount of equipment, control and protection modifications which would well exceed the cost of adding the HVDC converter capacity at this time.

Section:	Tab 4	Page No.:	PUB/MH I-22a, c
Topic:	Capital Expenditures		
Subtopic:	New Generation & Transmission Project Costs.		
Issue:	Increases in Capital Expenditures		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please refile the response to PUB/MH I-22(a) to include the years 2015 through 2024.

b) Please provide an update to PUB/MH I-22(c) to include the years 2015-2024.

c) Please indicate the number of EFTs per business unit attributable to the Internal MH Staff Costs.

RATIONALE FOR QUESTION:

To gain a better understanding of the composition of the Capital expenditures by major project.

RESPONSE:

a) Please see the response to PUB/MH-I-22b filed in confidence on March 20, 2015 for the forecast of Major New Generation and Transmission project costs for the years 2015-2024.

b) Please see the following table for the projection of the sustaining capital breakdown by asset type for each year from 2015-2024. As indicated in the response to PUB/MH-I-22c, the annual projections are based upon current asset condition and known requirements. The allocation of funds between asset types is continually reassessed taking into account changes in asset condition, capacity limitations, new customer requirements and other factors.

CEF14 Sustaining Capital by Asset Type

(in millions of dollars)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Generation Operations											
Turbines	$ 19.7	$ 13.4	$ 15.8	$ 28.8	$ 21.3	$ 20.8	$ 16.0	$ 12.6	$ 8.9	$ 9.3	$ 166.5
Generators	14.4	17.8	20.1	36.6	34.6	31.8	24.2	25.9	24.9	24.7	255.0
Auxiliary Systems (Sewer, Water, Fire, etc)	12.4	10.3	12.5	4.9	4.4	3.7	6.5	3.0	3.9	2.7	64.4
Transformers	12.4	7.4	7.9	11.3	10.5	12.2	14.7	16.1	28.4	27.7	148.4
Licensing	10.4	10.8	8.3	8.1	6.0	6.0	6.0	6.0	6.0	6.0	73.6
Instrumentation & Controls	9.0	15.1	11.8	4.3	4.1	6.1	6.2	3.8	4.3	4.2	68.8
Townsite Infrastructure	8.9	10.4	5.0	1.3	4.3	1.3	4.0	1.0	2.8	2.0	41.1
Breakers	8.9	4.3	1.3	3.0	7.1	7.1	11.1	12.1	10.1	7.2	72.3
Spillway & Water Controls	7.4	13.5	24.1	10.5	10.7	11.3	10.0	7.8	7.0	4.7	107.0
Powerhouse, Dams, Dykes	6.7	7.6	8.1	2.4	4.2	3.9	11.0	5.0	5.0	10.0	63.7
Physical Security & Public Safety	5.4	3.2	2.0	2.9	2.3	1.7	1.0	2.0	2.0	1.0	23.5
AC Supporting Electrical Systems	5.2	7.6	6.4	9.7	10.1	7.5	9.8	9.2	13.1	8.2	86.7
Governors	4.6	3.9	1.6	1.1	4.0	4.0	4.0	4.0	6.0	4.3	37.6
Exciters	2.9	3.5	3.7	5.1	6.4	6.5	5.0	6.4	4.9	7.3	51.6
Tools & Equipment	2.4	2.2	1.4	1.0	1.1	1.1	1.1	1.1	1.1	1.2	13.7
Communication Systems & Equipment	1.4	1.2	1.9	1.0	1.1	1.1	1.1	1.1	1.0	1.0	11.9
Combustion Turbines	-	-	-	-	-	6.0	0.4	17.5	7.8	18.7	50.4
	132.0	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**134.6**	**137.3**	**140.1**	**1,336.1**
Transmission											
Station Equipment	16.3	15.2	13.9	21.0	23.9	18.4	16.7	16.5	16.3	28.0	186.1
Station Civil Infrastructure	15.9	9.1	2.8	12.3	14.1	10.8	9.8	9.7	9.6	16.7	110.9
Transformers	15.2	12.5	12.6	15.2	4.5	7.5	3.1	7.9	1.5	9.8	89.9
Communication Systems & Equipment	14.5	7.2	8.6	10.0	9.6	10.2	10.8	10.1	10.3	10.6	101.9
Protection Relays & Control, Metering & SCADA	13.8	7.2	3.2	7.1	3.0	0.5	0.3	0.3	0.4	0.3	36.1
HVDC Synchronous Condensers	9.0	8.8	2.9	4.5	3.3	2.9	2.6	2.9	0.5	4.1	41.4
Steel Structures	7.3	12.4	34.0	26.5	18.7	16.9	15.7	14.7	17.7	16.0	179.6
Wood Poles	6.7	33.2	14.1	0.8	7.7	7.2	7.1	5.9	7.4	9.6	99.7
Breakers	6.7	5.3	3.7	8.5	7.4	7.4	4.9	0.7	1.0	5.0	50.6
Battery Banks	4.0	2.5	1.9	2.7	1.7	1.5	1.3	1.4	1.5	3.3	21.9
Conductor Attachments	3.6	4.4	5.1	0.1	0.9	0.7	0.5	0.5	0.7	1.8	18.4
HVDC Valve Group	2.8	0.7	0.1	2.4	13.2	23.1	60.1	60.8	65.3	21.8	250.2
Tools & Equipment	2.4	1.6	1.4	2.9	4.3	4.1	3.8	3.9	4.1	7.0	35.4
Land & Easements	2.3	1.1	10.2	2.1	2.2	2.8	3.7	0.9	1.1	3.7	30.2
Overhead Conductors	1.8	2.4	9.5	7.9	7.5	7.3	7.4	6.1	8.3	5.6	63.8
System Control Centre	0.4	0.3	0.3	0.5	0.8	0.7	0.7	0.7	0.7	1.2	6.3
Diesel Generation	0.4	-	-	0.4	1.9	2.9	1.8	7.0	3.6	5.5	23.5
HVDC Smoothing Reactors	0.1	0.4	0.5	-	-	-	-	-	-	-	1.0
Other	1.8	0.9	0.1	0.1	0.1	-	-	-	-	-	3.1
	125.0	**125.0**	**125.0**	**125.0**	**125.0**	**125.0**	**150.0**	**150.0**	**150.0**	**150.0**	**1,350.0**
Customer Services & Distribution											
Poles	43.3	38.5	48.3	42.5	42.5	42.5	42.5	43.4	44.3	45.1	433.0
Overhead Conductors	39.1	33.3	33.8	25.2	25.2	25.2	25.2	25.7	26.2	26.7	285.4
Underground Cables	31.3	37.3	45.5	36.6	36.6	36.6	36.6	37.4	38.1	38.9	375.1
Station Breakers and Other Station Equipment	23.8	29.6	28.7	20.5	20.5	20.5	20.5	20.9	21.4	21.8	228.3
Overhead Transformers	22.5	18.2	22.2	15.8	15.8	15.8	15.8	16.1	16.5	16.8	175.5
Station Transformers	21.0	23.1	24.7	16.9	16.9	16.9	16.9	17.3	17.6	18.0	189.5
Padmount Transformers	17.9	12.2	15.7	10.9	10.9	10.9	10.9	11.1	11.3	11.5	123.1
Street Lights	11.0	10.8	12.8	9.6	9.6	9.6	9.6	9.8	10.0	10.2	103.4
Ductlines & Manholes	7.9	16.0	13.2	12.0	12.0	12.0	12.0	12.2	12.4	12.7	122.4
Station Site Prep	6.0	9.2	9.3	6.3	6.3	6.3	6.3	6.4	6.6	6.7	69.4
Land & Easement	3.7	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.1
Buildings	4.4	10.1	12.7	8.6	8.6	8.6	8.6	8.8	9.0	9.1	88.5
Equipment	1.4	1.2	1.4	1.0	1.0	1.0	1.0	1.0	1.0	1.0	11.0
Steel Structures	0.8	0.7	-	-	-	-	-	-	-	-	1.6
Other	1.3	-	-	-	-	-	-	-	-	-	1.3
	235.5	**240.9**	**268.3**	**206.0**	**206.0**	**206.0**	**206.0**	**210.1**	**214.3**	**218.6**	**2,211.8**
Customer Care & Energy Conservation											
Meters & Meter Transformers	3.2	4.0	4.1	4.1	4.2	4.3	4.4	3.6	3.7	3.7	39.2
	3.2	**4.0**	**4.1**	**4.1**	**4.2**	**4.3**	**4.4**	**3.6**	**3.7**	**3.7**	**39.2**
Human Resources & Corporate Services											
Computers & IT Systems	29.0	29.1	29.6	27.6	27.2	28.4	28.5	29.1	29.8	30.5	288.9
Buildings	22.4	24.3	9.3	10.9	11.5	9.7	9.5	9.5	9.6	9.6	126.2
Fleet	21.0	18.9	13.3	13.6	13.4	13.9	14.0	14.3	14.6	15.0	152.0
Land & Easements	1.7	1.8	1.8	2.0	1.9	2.0	2.0	2.1	2.1	2.2	19.6
Tools & Equipment	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.1	1.1	1.1	10.0
	75.0	**75.0**	**55.0**	**55.0**	**55.0**	**55.0**	**55.0**	**56.1**	**57.2**	**58.4**	**596.7**
Finance Regulatory											
Tools & Equipment	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2
	0.2	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**2.2**
Target Adjustment	-	-	25.0	25.0	25.0	25.0	25.0	-	-	-	125.0
Sustaining Capital Total	**$570.9**	**$577.0**	**$609.6**	**$547.4**	**$547.4**	**$547.5**	**$572.6**	**$554.7**	**$562.8**	**$571.1**	**$5,660.9**

c) Please see Figures 5.5.8 and 5.5.10 in Appendix 5.5 for a breakdown of the capital construction EFTs by business unit (Straight Time and Overtime) for 2012/13 to 2016/17. As indicated in the response to PUB/MH-I-22c, detailed plans, including labor forecasts, are developed as individual projects are identified and approved while the forecast for sustaining capital is based upon the establishment of annual targets. As detailed projects have not been approved and allocated for the 10 year forecast, a breakdown of the capital EFT forecast outside of the test years, 2017/18 to 2023/24, is not available.

Section:	Tab 4: Figure 4.13 5: Schedule 5.1.6	**Page No.:**	PUB/MH I-23d
Topic:	Capital Expenditures		
Subtopic:	Electricity Capital In-Service Amounts		
Issue:	Conawapa Expenditures		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please describe the accounting treatment under IFRS for the accumulated Conawapa expenditures if those expenditures are not treated as a regulatory deferral account.

RATIONALE FOR QUESTION:

To understand alternatives to MH's proposed treatment of Conawapa costs and the impact on revenue requirement.

RESPONSE:

Based on the assumption that construction of the Conawapa Generating Station is suspended indefinitely, Manitoba Hydro would assess the nature of the sunk costs and determine whether those sunk costs continue to provide future benefit to the utility. The costs which continue to provide future benefit would continue to be deferred and remain in CWIP, whereas the costs no longer providing future benefit would result in an impairment loss and would be immediately charged to net income under IFRS, absent rate regulated accounting. Manitoba Hydro would continue to assess on an annual basis the remaining sunk costs to determine if they continue to provide future benefit to the utility.

Manitoba Hydro is mandated by the Province to supply adequate and reliable energy to meet the domestic energy needs of the Province; as such Manitoba Hydro needs to maintain a variety of plant options. This allows Manitoba Hydro to evaluate different sequences of plants as some may prove to be more optimal than others depending on conditions such as domestic load growth, export market conditions, and future Corporate strategy.

Given the time period between the initial studies for a new plant option and commencement of construction can be in the 20 - 30 year time frame, sunk costs associated with engineering studies and plant design would continue to hold their value into the future as these items are not likely to change over time for a new plant option. However, sunk costs associated with community agreements and environmental studies (e.g. fish and caribou studies) are not as likely to hold value long into the future as community agreements have termination provisions and the environmental conditions may change.

In IFF14, a simplifying assumption was made that the construction of the Conawapa Generating Station would not proceed following a review of the business case in 2016/17 and that all costs would be charged to a regulatory deferral account (per IFRS 14 *Regulatory Deferral Accounts*) and amortized over a 30 year period. However, the regulatory deferral account would initially include the costs no longer deemed as providing future benefit and this account would grow based on the periodic assessment of the remaining sunk costs to determine if the costs continue to provide future benefit to the utility.

Section:	Tab 4, Appendix 4.1	Page No.:	PUB/MH I-24(a)
Topic:	Capital Expenditures		
Subtopic:	Keeyask Project Costs		
Issue:	Revised cost estimate		

PREAMBLE TO IR (IF ANY):

MH has awarded contracts worth $2.74B with another $0.3B not yet awarded. This compares with a total project estimate of $6.496B.

QUESTION:

a) Provide the awarded contract item breakdowns requested in PUB/MH I-24(a).
b) File a redacted version on the public record and an unredacted version in confidence.

RATIONALE FOR QUESTION:

The Capital Project Justification (CPJ) sheets lack component cost details.

RESPONSE:

Contract	Status	Value	Type
General Civil Works	Awarded. Work Started	$1.4 B	Target Price
Turbines & Generators	Awarded. Work Started	[redacted]	Fixed Price
Main Camp Facility - Phase 1 & 2	Awarded. Work Started		Unit Price
Catering & Janitorial Services - Phase 1 & 2	Awarded. Work Started		Cost Reimbursable
Final Design Engineering	Awarded. Work Started		Unit Price
South Access Road	Not Awarded as of December 31, 2014	TBD	Unit Price
Staff Augmentation	Awarded for three year Term	TBD	Unit Price

Note 1: The above list includes contracts for which the awarded value or the estimated value exceeded $50M as of December 31, 2014.

Please note that escalation costs for the Keeyask total project estimate are based on standard corporate policy rates. An escalation reserve is also carried for the project which is intended to represent the potential additional costs to the project associated with cost escalation greater than Canadian CPI. The reserve is based on the additional costs associated with a standard year-over-year escalation rate of 2.5%, compared to escalation following Canadian CPI. This standard rate was obtained by taking the average escalation rate between the Canadian CPI and a composite escalation rate (or “basket” rate) of commodities typical of a hydroelectric generating station (e.g. steel, cement, construction labour, etc.). The composite escalation rate is developed by combining a number of individual market escalation indices (items such as construction labour, steel, cement, etc.), based on their estimated use in the construction of a generating station, to form a single composite rate. For each contract, specific escalation clauses apply which will cause a positive or negative change in the actual cost of the work depending on the indices which are driven by the marketplace. For example, the General Civil Contract has escalation clauses for craft labour, steel, fuel, cement, etc.

Section:	Tab 4	**Page No.:**	PUB/MH I-25(a)
Topic:	Capital Expenditures		
Subtopic:	Pointe du Bois Powerhouse Rebuild		
Issue:	Cost/Revenue Analysis		

PREAMBLE TO IR (IF ANY):

MH's CEF14 leaves some doubt as to whether the Pointe du Bois powerhouse rebuild has been cancelled completely.

QUESTION:

a) Please reconcile Manitoba Hydro’s comments set out at page 117 of its NFAT final written submissions indicating that the Pointe du Boise powerhouse rebuild was cancelled with the table on page 2 of CEF14.

b) Please explain what expenditures Manitoba Hydro intents to make with respect to the powerhouse replacement.

RATIONALE FOR QUESTION:

This question seeks clarification on Pointe du Bois expenditures.

RESPONSE:

a) The reference in the NFAT final written submission to cancellation of the Pointe du Bois powerhouse rebuild was made in the context of other examples where Manitoba Hydro has adjusted its long term planning decisions in the past. In the specific reference to Pointe du Bois, the decision was made in 2009 to cancel the powerhouse rebuild component of a larger overall plan, the Pointe du Bois Modernization Project. This project would have resulted in Manitoba Hydro rebuilding both the Pointe du Bois spillway and powerhouse as an integrated project, with a powerhouse in-service date of 2016/17. The decision at that time was made to proceed with the Spillway Replacement Project and defer the powerhouse rebuild, which for planning purposes was revised to 2030/31. For IFF14, based on ongoing review and experience at Pointe du Bois, the powerhouse rebuild was further deferred to the 2040's timeframe under the expectation that operation of the existing powerhouse can be extended.

b) There are no committed expenditures for the Pointe du Bois powerhouse rebuild. The overall need and timing of capital expenditures for replacement of the Pointe du Bois powerhouse are under review.

Section:	Tab 5: Appendix 5.5	**Page No.:**	PUB/MH I-32 b, d & e
Topic:	Financial Results & Forecasts		
Subtopic:	Wages and Labour		
Issue:	Staffing Levels		

PREAMBLE TO IR (IF ANY):

MH has not provided the capitalized labour and benefits for 2007/08 through 2011/12 even though such information was previously provided in PUB/MH I-38 (d) & (e) from the 2012 GRA. MH has indicated that the EFT data is only available in the new format beginning in the 2012/13 fiscal year.

QUESTION:

a) Please confirm or correct the following attached schedule derived from PUB/MH I-38 (e) from the 2012 GRA. Also include the percentage of labour and benefits capitalized and the EFT's (S/T & O/T) capitalized, and average salary capitalized for each of the years through 2016/17.

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	205/16 Forecast	2016/17 Forecast
Wages & Salaries (ST & OT Combineds)										
Wages & Salaries	359,249	380,031	407,988	425,158	451,925	466,165	480,511	502,692	524,552	533,997
Overtime	41,781	45,890	50,307	50,704	54,987	61,031	62,365	61,709	71,080	73,121
Benefits	76,807	83,671	82,674	95,376	104,444	130,886	157,095	160,592	155,892	158,992
Labour and Benefits	$477,837	$509,592	$540,969	$571,238	$611,356	$658,082	$699,971	$724,993	$751,524	$766,110
Labour & Benefits Capitalized (Note 1)	$185,900	$193,500	$207,600	$221,200	$246,800	$215,491	$234,510	$256,588	$282,335	$287,969
Labour & Benefits Charged to Operations	$291,937	$316,092	$333,369	$350,038	$364,556	$442,591	$465,461	$468,405	$469,189	$478,141
as a percentage of total Labour and Benefits	39%	38%	38%	39%	40%	33%	34%	35%	38%	38%
EFTs (S/T & O/T) capitalized (Notes 1,2)	2,369	2,397	2,479	2,566	2,678	2,825*	2,204	2,362	2,568	2,580
Average Salary Capitalized	78.47	80.73	83.74	86.20	92.16	?	106.40	108.63	109.94	111.62

* Forecast based on PUB/MH I-38e (2012/13 & 2013/14 GRA)

Sources

1. Labour and benefits capitalized and Capital EFT's for 2007/08 through 2012/13 based on PUB/MH-I-38e (2012/13 & 2013/14 GRA)
2. EFTs assigned to capital construction for 2013/14 to 2016/17 based on PUB/MH-I-32e
3. The EFT's for 2012/13 are based on forecast provided in PUB/MH I-38e (2012/13 & 2013/14 GRA)

b) Please explain why historically reported financial results are no longer available as a result of system changes in 2012/13.

c) Please explain the trend of increasing Average Salary capitalized per EFT.

d) Please indicate how the Corporation has determined EFTs assigned to Capital Construction, Operations and Maintenance and Governance, Support & Services and explain whether and how EFTs assigned to Capital have changed from what was previously provided for 2007/08 through 2011/12.

e) Provide a comparison of the EFTs assigned to Capital Construction for 2012/13 at the 2012 GRA with actual.

f) Please provide a breakdown of the number of staff by business unit which has been assigned to Capital Construction, Operations & Maintenance, and Governance Support & Services for each of the years 2013/14 through 2016/17.

RATIONALE FOR QUESTION:

RESPONSE:

a) In the 2012/13 and 2013/14 Electric General Rate Application (GRA 2012 PUB/MH I-38d), Manitoba Hydro was requested to provide an estimate of the amount of labour and benefits capitalized which included an approximation of the amount of support and governance staff capitalized through overhead. The response stated that the "*direct quantification of the labour and benefit component of both activity charges and overhead is not available as the approach taken by Manitoba Hydro is one of cost allocation*."

Labour & benefits and EFTs capitalized as shown in the response to PUB/MH-I-32 d) & e) of the current filing do not include an estimate for support and governance staff capitalized through overhead. As such the labour and benefits capitalized in the schedule provided in the question above for the years 2007/08 through 2011/12 are not comparable to the figures provided for the years 2012/13 through 2016/17 as shown in PUB/MH-I-32d.

b) In 2012/13 changes were made to activity rates to support the transition to IFRS by excluding costs embedded in activity rates that would no longer be eligible for capitalization. In addition, modifications were made to overhead rates and Manitoba Hydro's internal cost allocation methodology. These changes were made on a go-forward basis and as a result both labour and expense capitalized and EFTs capitalized provided in the current filing cannot be restated in the new format prior to 2012/13.

c) The calculation in the schedule provided in the question above does not represent the average salary per EFT. Appendix 11.25 Operating Expenses MFR 5 provides the average salary per EFT by business unit and division for 2009/10 to 2016/17. The average salary per EFT is the same regardless of whether the employee charges to a capital project or operating program. The increase in the average salary per EFT reflects the impacts of contract settlements and higher benefit costs.

d &e)

As outlined in Appendix 5.5, Operating, Maintenance & Administrative Expense, Section 4.0, Staffing Requirements to Manage Operations & Capital Investment:

1. Capital Construction EFTs – staff who charge their time to capital projects approved within the Capital Expenditure Forecast (CEF). The hours charged must be incremental, non-discretionary and directly attributable in order to be eligible for capitalization.
2. Operations and Maintenance EFTs – staff who charge time to operating and maintaining the electric, gas and various infrastructure assets of the corporation.
3. Governance, Support & Services EFTs:

   i. Governance – staff that provide direction and oversight regarding the actions, policies and decisions of the Corporation. This category includes functions such as internal audit, legal and executive.
   ii. Support & Services - staff that provide corporate and divisional support services such as human resources, information systems, division and department managers, as well as departmental support activities not directly allocated to the capital construction or operations and maintenance functions of the corporation.

Capitalized EFTs in PUB/MH I-38 (d) & (e) from the 2012 GRA includes staff that charge their time directly to capital projects as well as an estimate of support and governance staff capitalized through overhead. Actual capitalized EFTs for 2012/13 provided in the current filing are not comparable as they do not include an estimate of support and governance staff capitalized through overhead.

f) Please refer to Appendix 5.5, Figures 5.5.8 and 5.5.10 for a breakdown of Capital Construction, Operations & Maintenance and Governance Support & Services EFTs by Business Unit (Straight Time and Overtime) for each of the years 2012/13 through 2016/17.

Section:	Tab 5: 5.4 Cost Savings Initiatives	**Page No.:**	PUB/MH I-33(f)
Topic:	Financial Results & Forecasts		
Subtopic:	Cost Savings Initiatives		
Issue:	Impact of Policy Changes Since 2008		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update the table to add a column indicating number of MH employees eligible to retire in each year from 2010 through 2017. Also include the forecast retirements.

RATIONALE FOR QUESTION:

To explore staffing reductions through retirements.

RESPONSE:

Calendar year	Permanent active workforce at start of year	Actual retirements	Retirement rate	Number eligible in current year	Number becoming eligible in forecast year	Predicted number of retirements
2010	5783	146	2.5%			
2011	5909	182	3.1%			
2012	5891	132	2.2%			
2013	5978	144	2.4%			
2014	6039	161	2.7%			
2015				903		181
2016					195	183
2017					211	189
2018					205	192
2019					248	203
2020					216	206
2021					215	208
2022					198	206
2023					163	197
2024					161	190

Definition:

Permanent active workforce -- the count of all non-terminated employees whose employment type is not “Term” or “Student”. Include individuals on leaves of absence. Forecasts for the future size of this workforce are not available.

Actual retirements -- does not include disability retirements.

Retirement rate -- Actual retirements divided by the permanent active workforce.

Number eligible in current year -- those becoming eligible for a full, undiscounted pension in 2015 (based on age and years of service.) Includes individuals who were eligible in previous years but who have not taken up the retirement opportunity.

Number becoming eligible in forecast year -- those becoming eligible in each of the years in the forecast window.

Predicted number of retirements -- Based on a historical retirement take-up rate of 20%. That rate is applied to the number eligible in the current year to arrive at the retirement prediction for the current year. The remainder is carried forward to the next year and is added to the number becoming eligible in that forecast year. The take-up rate is applied to that sum to arrive at the forecast prediction for that year. The process carries forward to the end of the forecast window.

Section:	Tab 5: Appendix 5.5	Page No.:	PUB/MH I- 35 (a) & (b) PUB/MH I-22(a)
Topic:	Financial Results & Forecasts		
Subtopic:	OM&A Expense		
Issue:	Cost Savings Initiatives		

PREAMBLE TO IR (IF ANY):

PUB/MH I-22(a) indicates that internal staff costs for Conawapa were $6.9 million in 2012/13 and $10.6 million in 2013/14. PUB/MH I-35 (a) indicates payroll costs of $4.9 million in 2012/13 and $8.1 million in 2013/14.

QUESTION:

a) Please reconcile the internal staff costs charged to Conawapa in PUB/MH I-22 (a) with PUB/MH I-35 (a) for 2012/13 and 2013/14.

b) Please provide an update to the table of Conawapa EFTs, payroll costs and reconcile with forecast internal staff costs for each of the years 2012/13 through 2016/17.

c) Please provide the response to PUB/MH I-35 (b) based on IFF12.

RATIONALE FOR QUESTION:

RESPONSE:

a) The internal staff costs charged to Conawapa from 2012/13 to 2013/14 in PUB/MH-I-22(a) includes both activity charges and capitalized overhead, whereas PUB/MH-I-35(a) provides an estimate of the payroll cost component embedded in the activity rate charge. The payroll cost component is on average 88% of the total activity rate.

b) Please see the response to PUB/MH-I-22b filed in confidence, which provides the forecasted internal staff costs charged to Conawapa for the years 2014/15 through 2016/17. The response to PUB/MH-I-35bR provides the estimated EFTs and payroll costs over the same period. As noted in part a, the payroll cost component is embedded in the activity rate charge and is on average 88% of the total activity rate charge.

c) The CEF12 forecast for the Conawapa project prepared in 2012/13 had included a high level estimate of labour costs for the years 2014/15 and beyond. As a result, the breakdown of internal staff costs, payroll costs and EFTs by business unit is not available.

Section:	Tab 5: Appendix 5.6	**Page No.:**	PUB/MH I-37 (b)
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

The Board could prescribe a different method of depreciation for rate-setting purposes than used for Manitoba Hydro's financial reporting.

QUESTION:

a) Please refile the schedule eliminating the change to ELG, assuming the continuation of ASL.

b) Please indicate the equal annual percentage rate increase MH would request based on (a).

c) Please discuss the implication on financial reporting if a regulatory accounting approach to depreciation expense were to be established, discretely using ASL for rate setting purposes.

RATIONALE FOR QUESTION:

This question explores the rate impact of continuing to use ASL for rate-setting purposes.

RESPONSE:

a) Please see the attached chart for the net impact on depreciation expense for the 20 year period in IFF14 assuming the continuation of CGAAP ASL and the removal of net salvage. Consistent with the requirements of the IFRS standard, *IFRS 14 Regulatory Deferral Accounts*, the chart reflects the amortization of a new regulatory deferral account established to capture the annual and cumulative difference between depreciation expense compliant with IFRS and the CGAAP ASL depreciation expense. The deferral account is assumed to be amortized into net income over a period of 10 years. For more information on the deferral account, please see the response to part (c) of this question below.

	Depreciation Expense ($ millions)																				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**Total**
Change in service life - PP&E (net of contributions)	(25)	(29)	(30)	(30)	(34)	(38)	(43)	(41)	(43)	(42)	(42)	(40)	(36)	(39)	(40)	(40)	(40)	(39)	(38)	(37)	(746)
Overhead ineligible for Capitalization	-	-	(2)	(4)	(6)	(7)	(9)	(11)	(13)	(14)	(16)	(18)	(20)	(22)	(23)	(25)	(27)	(29)	(31)	(33)	(310)
Meter Compliance, Exchange and Sampling	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	13
Elimination of Provision for Asset Removal	-	(60)	(63)	(67)	(86)	(96)	(107)	(117)	(117)	(119)	(120)	(122)	(125)	(127)	(130)	(132)	(134)	(136)	(140)	(143)	(2 141)
Change in Methodology (ELG)	-	36	38	41	49	55	63	67	68	69	69	70	72	73	75	76	77	79	80	81	1 238
Net Impact on Depreciation Expense Increase (Decrease)	**(25)**	**(53)**	**(57)**	**(60)**	**(77)**	**(86)**	**(96)**	**(101)**	**(104)**	**(105)**	**(108)**	**(109)**	**(108)**	**(114)**	**(117)**	**(120)**	**(123)**	**(124)**	**(128)**	**(131)**	**(1 946)**

Adjustments to Response to PUB/MH I-37b

Remove: impact of changing to ELG	-	(36)	(38)	(41)	(49)	(55)	(63)	(67)	(68)	(69)	(69)	(70)	(72)	(73)	(75)	(76)	(77)	(79)	(80)	(81)	(1 238)
Add: Amortization of regulatory deferral account	-	7	11	15	20	25	31	38	45	52	59	59	62	66	68	70	72	73	74	75	921
Net Impact on Depreciation Expense Increase (Decrease)	**(25)**	**(82)**	**(84)**	**(86)**	**(106)**	**(116)**	**(127)**	**(130)**	**(127)**	**(122)**	**(118)**	**(120)**	**(118)**	**(121)**	**(124)**	**(126)**	**(128)**	**(130)**	**(134)**	**(137)**	**(2 262)**

b) Based on the assumption of the continuation of the CGAAP ASL procedure without net salvage as posed in the question, Manitoba Hydro would continue to request a rate increase of 3.95% so as to ensure the utility's financial position is strong enough to absorb future financial risks and avoid volatility in customer rates in the future.

Under this scenario, customer rate increases are projected at 3.90% annually from 2018 through to 2031 and 2.0% thereafter are required in order to achieve a 25% equity ratio by 2034, assuming a reduction in depreciation from the continued use of CGAAP ASL in conjunction with the amortization required for the new regulatory deferral account. Please see attachment 1 to this response for the projected financial statements associated with this scenario. A summary of the results is as follows:

Account	March 31, 2034
Retained Earnings (MH14)	**5 557**
Depreciation expense reduction – continue with CGAAP ASL (no net salvage)	1 238
Depreciation expense increase – amortization of Deferral Account (10 year amortization period)	(921)
Reduction in customer rate revenue via 3.90% increases	(184)
Increase in Finance expense for higher debt levels	(81)
Increase in Capital taxes for higher debt levels	(23)
Reversal of the 2015 Retained Earnings adjustment for the change to ELG depreciation	33
Ending Retained Earnings	**5 619**
Net change in Retained Earnings	**62**

As Manitoba Hydro indicated at the 2012/13 & 2013/14 GRA, the decision to remove net salvage from depreciation rates was taken in order to manage the overall impacts of the transition to IFRS, including the impacts of moving to the ELG depreciation methodology. As such, Manitoba Hydro's proposal to move to ELG and discontinue net salvage was an overall approach in order to ensure that there were no negative impacts to customers as a result of accounting policy selection by Manitoba Hydro. Manitoba Hydro's position is that, from an overall fairness perspective, the PUB should consider the impacts of the proposed depreciation changes for rate-setting purposes as a whole, rather than focusing only on the change to ELG.

In order to understand the overall implications of proposed depreciation changes for rate-setting purposes, Manitoba Hydro has developed an additional financial statement scenario that assumes the continuation of CGAAP ASL and the continuation of the inclusion of asset removal costs (i.e. net salvage) in depreciation rates for rate-setting purposes. Under this scenario, customer rate increases are projected at 3.98% annually from 2018 through to 2031 and 2.0% thereafter are required in order to achieve a 25% equity ratio by 2034. Please see attachment 2 to this response for the projected financial statements associated with this scenario. As part of this scenario, Manitoba Hydro has assumed the creation of a regulated asset deferral account to record the differences between CGAAP ASL and IFRS ELG as in the scenario above, as well as the creation of a regulated liability deferral account to record net salvage, which is not IFRS compliant. Manitoba Hydro has assumed that both the asset and liability deferral accounts would be amortized into net income over a period of 10 years. A summary of the results of this scenario are as follows:

Account	March 31, 2034
Retained Earnings (MH14)	**5 557**
Depreciation Expense increase - Provision for net salvage	(2 141)
Depreciation expense reduction – continue with CGAAP ASL (no net salvage)	1 238
Depreciation expense decrease – amortization of Deferral Liability Account (10 year amortization period)	1 588
Depreciation expense increase – amortization of Deferral Asset Account (10 year amortization period)	(921)
Increase in customer rate revenue via 3.98% increases	99
Decrease in Finance expense for lower debt levels	43
Decrease in Capital taxes for lower debt levels	17
Reversal of the 2015 Retained Earnings adjustment for the change to ELG depreciation and Net Salvage	(24)
Ending Retained Earnings	**5 456**
Net change in Retained Earnings	**(101)**

Overall, the results of the two scenarios above reinforce that Manitoba Hydro's proposed and indicative rate increases of 3.95% are not driven by the accounting changes as identified in Schedule A of Appendix 5.7 of the Application. The accounting changes only alter the timing between CGAAP and IFRS as to when such expenses are recognized into net income.

Furthermore, the PUB explicitly rejected the recommendations by intervenors at the 2012/13 & 2013/14 GRA to reduce rate increases by assuming different accounting policies for rate-setting purposes, finding at page 10 of Order 43/13:

> *"Interveners recommended various accounting changes to lessen rate increases over the test years. The Board rejects this approach as it would have the effect of reducing Manitoba Hydro's revenues, weakening its financial situation, and increasing borrowing costs. It is important that Manitoba Hydro remain a financially strong and viable organization."*

c) Manitoba Hydro has interpreted the term "*discretely using ASL for rate setting purposes*" to imply having two separate sets of financial statements, one for financial reporting purposes and one for rate-setting purposes, or preparing alternate set of depreciation calculations to assess rate requirements.

Under the scenario specified in the question, a new regulatory deferral account would have to be created consistent with the requirements of IFRS 14, to capture the annual and cumulative differences between depreciation expense compliant with IFRS and depreciation expense used for rate-setting purposes (CGAAP ASL). Net income before the impact of Regulatory Deferral Accounts would include depreciation expense compliant with IFRS (ELG) and net income after the impact of regulatory deferral accounts would include depreciation expense based on a CGAAP ASL method. This accounting treatment would be necessary to be in compliance with the financial reporting requirements of IFRS interim standard *IFRS 14 - Regulatory Deferral Accounts* which requires an all or nothing approach to recognizing rate regulated accounts. As per paragraph 8 of IFRS 14,

8 An entity that is within the scope of, and that elects to apply, this Standard shall apply all of its requirements to <u>all regulatory deferral account balances</u> that arise from <u>all of the entity's rate-regulated activities</u>.

However, the establishment of a regulatory deferral account would require Manitoba Hydro to maintain two sets of PP&E sub ledger records to support the before and after regulatory impact balances presented in the financial statements. This would require the recognition of all transactions associated with depreciation expense and gains and losses on asset retirements to be recognized in separate sub-ledgers. Going forward, cost and accumulated depreciation balances in the two sub-ledger accounts would be very different. The process for maintaining two PP&E sub-ledgers will be extremely onerous, time consuming and costly given the thousands of transactions that are recorded each year for Manitoba Hydro's $16 billion of assets. Manitoba Hydro currently has 93,000 assets with values in its subledger books and its asset balance is projected to almost double in the next 20 years. It is also anticipated that the PUB would require an audit to be performed on the PP&E related balances used for rate-setting purposes. In addition, as compared to performing a single depreciation study for financial reporting purposes, Manitoba Hydro would be required to perform two studies, one based on ELG rates and one based on ASL rates.

In addition, in order to maintain a separate set of financial statements or alternate set of depreciation calculations for rate-setting purposes, the following administrative efforts may be required:

- Monthly and quarterly financial reports;
- Annual forecasting requirements (i.e. 2 different Integrated Financial Forecasts, one for rate setting purposes and one for other users such management, financial institutions, government);
- Quarterly/annual reconciliation of PP&E related accounts;
- Annual audit of depreciation rates / expense, asset retirement gains and losses, and PP&E net book value balances; and
- Depreciation Studies

Manitoba Hydro's position is that the transition to IFRS should not trigger the requirement for a separate set of financial statements or alternate set of depreciation calculations for rate-setting purposes. These steps are not necessary under the cost of service rate-setting methodology that is used to set electric rates in Manitoba. Unlike the rate base/rate of return methodology that is used to set rates in other jurisdictions, the cost of service approach used in Manitoba does not determine rates based strictly on changes in costs and an established capital structure and return on equity. Rather the cost of service methodology coupled with Manitoba Hydro's approach of implementing regular and reasonable rate increases has the flexibility to recognize changes in costs and levels of retained earnings and transition these changes into rates gradually over time, while at the same time ensuring the maintenance of an adequate financial structure over the long-term. This approach serves to protect customers from sudden or large rate increases and makes a separate set of regulatory financial statements unnecessary.

One of the benefits of the cost of service rate setting methodology employed in Manitoba is that the PUB uses the same set of general purpose financial statements and information to set rates as Manitoba Hydro, the Manitoba Hydro-Electric Board and other external users of the statements (such as credit rating agencies) for their purposes. This reduces the potential confusion associated with different users looking at multiple sets of financial information to make decisions, evaluate financial performance and assess rate requirements and improves the transparency of the rate-setting process by aligning the basis used to set rates and report results. The use of audited financial information in the rate-setting process also improves the reliability of the information.

In addition, as noted above, there are significant administrative costs associated with reconciling between the different sets of financial information and maintaining duplicate transactional accounting that would be necessary to produce reliable and complete regulatory reporting. This would simply add to the regulatory compliance costs that customers ultimately must bear without any additional benefit to them.

Maintaining two sets of financial statements conflicts with the lobbying that North American utilities and regulators have done with the International Accounting Standards Board (IASB) to develop an accounting standard that recognizes the impacts of regulatory decisions for financial reporting. The August 30, 2013 letter from Canadian Association of Members of Public Utility Tribunals ("CAMPUT") to the IASB regarding the IASB Exposure Draft on Regulatory Deferral Accounts describes the views and concerns of regulators with respect to maintaining two separate sets of financial statements. Please see Attachment 3 to this response for a complete copy of the CAMPUT letter to the IASB. Manitoba Hydro notes the following relevant excerpts, with emphasis added by underlining.

page 2. *The Canadian rate regulators endorse the IASB's initiative to enable rate-regulated utilities to continue to recognize regulatory balances in their financial statements. The chairs of these regulatory commissions and boards have approved the contents of this comment letter and considered it very important that the interim Standard be put in place.*

page 3*. "The interim Standard resolves one major problem for entities with rate-regulated operations. Our observation is that, without the interim Standard, these rate-regulated entities will be required to provide two sets of financial statements, as has happened in some other jurisdictions and as was acknowledged by the IASB9: one to meet general purpose financial reporting requirements under IFRS; and, the other to present to the rate regulator for purpose of (i) requesting rate adjustments, (ii) regulatory accounting and rate-making, and (iii) regulatory reporting. As regulators, we find it unsatisfactory and not serving the public interest if there are two views of economic reality of entities with rate-regulated operations. Rate regulators are aware that their actions have significant economic impact, including investment, lending and consumer prices. The IASB has acknowledged that many of rate-regulated entities argue that recognizing such balances as assets and liabilities would provide more relevant information and would be a more representationally faithful way of reporting their rate-regulated activities. Some of these utilities had to eliminate regulatory deferral account balances from the statement of financial position when they adopted IFRS and do not recognize such balances in IFRS financial statements. It behooves the accounting profession to find the appropriate ways to ensure all economic events are reflected in the base numbers reported in general purpose financial statements. Requiring rate-regulated entities to leave certain economic events outside the purview of the financial statements, or at best relegated to note disclosure, is not good enough for regulatory actions that affect prices. Furthermore, exclusion of certain economic events would not serve the needs of users of the financial statements.*

Finally on this point, the results of having two views will add confusion and unnecessary complexity and higher cost to the rate-regulated entities and their customers such as maintaining two sets of books. Furthermore, the investors or the lenders of the rate-regulated entities will find it confusing to decide which set of financial statements to use when monitoring financial performance to judge the financial soundness of the enterprises. The IASB's proposed interim Standard addresses the above concerns. Therefore, we support the IASB's development and application of the interim Standard.

page 4. *Our position is that IASB's proposed changes to recognize valuing and reporting regulatory deferral account balances not only enhance the comparability of* *information within the general financial statements, but also, they offer transparency of financial information to the users. Thus, the proposed changes by the IASB are vital to the credibility and usefulness of any financial statements that are prepared for the users.*

Overall, Manitoba Hydro supports the comments made in the CAMPUT letter that maintaining two sets of books will only add confusion and unnecessary complexity and will not serve the needs of the various users of the financial statements.

ELECTRIC OPERATIONS (PUB_MH_II_21b_CGAAP ASL with No Salvage)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	57	118	182	248	318	391	467	548	634
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	2 008	2 100	2 221	2 349	2 728	2 939	3 048	3 175
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	548	581	752	887	1 194	1 326	1 335	1 351
Depreciation and Amortization	405	372	395	419	492	494	581	638	713	735
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	135	144	145	145	152	152	162
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 795	1 929	2 018	2 289	2 442	2 890	3 123	3 219	3 289
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	144	86	89	(63)	(90)	(152)	(183)	(172)	(117)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.27%	16.65%	21.21%	25.93%	30.85%	35.95%	41.26%
Financial Ratios										
Equity	22%	18%	17%	16%	15%	14%	13%	11%	11%	10%
Interest Coverage	1.16	1.20	1.10	1.09	0.94	0.93	0.88	0.86	0.87	0.91
Capital Coverage	0.98	1.02	0.94	1.09	0.88	0.80	0.81	0.93	1.08	1.21

ELECTRIC OPERATIONS (PUB_MH_II_21b_CGAAP ASL with No Salvage)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	1 551	1 565	1 580	1 593	1 607	1 624	1 641	1 659	1 677	1 696
additional*	726	822	923	1 030	1 142	1 262	1 390	1 466	1 545	1 627
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3 289	3 333	3 464	3 562	3 687	3 832	3 960	4 045	4 125	4 227
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 354	1 352	1 341	1 342	1 327	1 308	1 274	1 208	1 174	1 130
Depreciation and Amortization	757	768	782	796	805	815	826	836	850	867
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	163	164	165	166	168	169	170	171	174	176
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3 339	3 359	3 384	3 414	3 431	3 442	3 438	3 410	3 411	3 413
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(55)	(28)	77	142	249	380	510	620	696	794
* Additional General Consumers Revenue										
Percent Increase	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	2.00%	2.00%	2.00%
Cumulative Percent Increase	46.77%	52.50%	58.45%	64.63%	71.06%	77.73%	84.67%	88.36%	92.13%	95.97%
Financial Ratios										
Equity	10%	10%	11%	12%	13%	14%	17%	19%	22%	25%
Interest Coverage	0.96	0.98	1.06	1.10	1.18	1.29	1.39	1.50	1.58	1.68
Capital Coverage	1.25	1.29	1.45	1.55	1.66	1.90	1.99	2.15	2.24	2.36

ELECTRIC OPERATIONS (PUB_MH_II_21b_CGAAP ASL with No Salvage)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 295	2 598	2 728	2 167	2 238	2 442
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	340	403	468	541	595	640	666	673	673
	16 993	18 928	21 890	25 077	26 730	27 843	28 505	27 962	28 046	28 240
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 906	22 792	22 955	23 250	23 441
Current and Other Liabilities	2 016	2 151	2 097	3 071	2 218	2 662	2 618	2 124	2 056	2 139
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 840	2 926	3 015	2 952	2 862	2 711	2 527	2 356	2 238
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 928	21 890	25 077	26 730	27 843	28 505	27 962	28 046	28 240

ELECTRIC OPERATIONS (PUB_MH_II_21b_CGAAP ASL with No Salvage)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823	42 952
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 384)	(17 200)	(18 031)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 710	24 666	24 623	24 921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 387	2 537	2 788	3 095	3 301	3 831	3 655	4 281	4 920	5 623
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	659	650	639	627	621	621	624	634	648	661
	28 200	28 360	28 609	28 893	29 084	29 575	29 388	30 005	30 668	31 460
LIABILITIES AND EQUITY										
Long-Term Debt	23 595	24 198	24 401	24 543	24 476	23 949	23 939	23 943	23 937	23 581
Current and Other Liabilities	1 962	1 509	1 442	1 404	1 377	1 977	1 252	1 208	1 141	1 455
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2 184	2 155	2 231	2 373	2 622	3 001	3 510	4 129	4 825	5 619
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	28 200	28 360	28 609	28 893	29 084	29 575	29 388	30 005	30 668	31 460

ELECTRIC OPERATIONS (PUB_MH_II_21b_CGAAP ASL with No Salvage)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	2 039	2 133	2 229	2 346	2 726	2 937	3 046	3 173
Cash Paid to Suppliers and Employees	(803)	(871)	(943)	(974)	(1 000)	(1 016)	(1 070)	(1 100)	(1 125)	(1 157)
Interest Paid	(511)	(514)	(547)	(593)	(784)	(928)	(1 222)	(1 350)	(1 330)	(1 342)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	587	571	597	480	438	464	515	605	689
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 600	1 590	600	560	580
Sinking Fund Withdrawals	110	21	-	7	448	204	294	716	165	27
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 470	933	573	243	285
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(245)	(262)	(358)	(252)	(259)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 516)	(1 830)	(1 302)	(1 144)	(981)	(986)
Net Increase (Decrease) in Cash	(270)	(78)	84	(54)	(23)	77	95	(56)	(132)	(12)
Cash at Beginning of Year	133	(137)	(215)	(131)	(185)	(209)	(131)	(36)	(92)	(225)
Cash at End of Year	(137)	(215)	(131)	(185)	(209)	(131)	(36)	(92)	(225)	(237)

ELECTRIC OPERATIONS (PUB_MH_II_21b_CGAAP ASL with No Salvage)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 287	3 330	3 461	3 559	3 684	3 828	3 957	4 041	4 121	4 223
Cash Paid to Suppliers and Employees	(1 181)	(1 191)	(1 213)	(1 227)	(1 249)	(1 270)	(1 290)	(1 315)	(1 336)	(1 364)
Interest Paid	(1 349)	(1 355)	(1 357)	(1 373)	(1 378)	(1 363)	(1 351)	(1 262)	(1 243)	(1 214)
Interest Received	20	22	35	49	62	71	84	63	78	93
	776	805	926	1 008	1 120	1 266	1 400	1 528	1 620	1 738
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	590	580	190	190	(20)	170	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	297	104	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	454	203	161	163	(45)	178	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(271)	(270)	(279)	(292)	(305)	(313)	(323)	(300)	(312)	(323)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 045)	(1 052)	(1 057)	(1 063)	(1 093)	(1 087)	(1 136)	(1 127)	(1 184)	(1 277)
Net Increase (Decrease) in Cash	185	(43)	31	108	(18)	357	223	343	389	415
Cash at Beginning of Year	(237)	(51)	(95)	(64)	44	26	383	606	949	1 338
Cash at End of Year	(51)	(95)	(64)	44	26	383	606	949	1 338	1 753

ELECTRIC OPERATIONS (PUB_MH_II_21b_CGAAP ASL with Salvage)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	57	118	183	251	322	396	474	557	645
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	2 008	2 101	2 223	2 353	2 734	2 946	3 057	3 186
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	548	581	752	887	1 193	1 325	1 333	1 348
Depreciation and Amortization	405	420	440	462	545	548	635	689	753	765
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	120	134	143	143	144	150	150	160
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 843	1 974	2 060	2 340	2 493	2 941	3 172	3 255	3 314
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	97	42	48	(111)	(137)	(197)	(225)	(199)	(131)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.35%	16.82%	21.46%	26.29%	31.31%	36.53%	41.96%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	13%	12%	10%	9%	9%
Interest Coverage	1.16	1.13	1.05	1.05	0.90	0.89	0.85	0.83	0.85	0.90
Capital Coverage	0.98	1.02	0.94	1.09	0.88	0.81	0.82	0.95	1.10	1.23

ELECTRIC OPERATIONS (PUB_MH_II_21b_CGAAP ASL with Salvage)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	1 551	1 565	1 580	1 593	1 607	1 624	1 641	1 659	1 677	1 696
additional*	739	837	941	1 050	1 165	1 289	1 420	1 497	1 577	1 661
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3 302	3 348	3 482	3 582	3 710	3 858	3 991	4 076	4 157	4 260
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 350	1 346	1 334	1 333	1 316	1 295	1 260	1 192	1 156	1 111
Depreciation and Amortization	776	789	799	810	817	825	835	847	862	879
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	161	162	163	164	165	166	167	169	171	173
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3 352	3 371	3 391	3 417	3 429	3 437	3 431	3 402	3 402	3 403
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(54)	(25)	87	161	275	411	548	659	738	838
* Additional General Consumers Revenue										
Percent Increase	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.61%	53.47%	59.58%	65.92%	72.52%	79.38%	86.51%	90.24%	94.04%	97.92%
Financial Ratios										
Equity	9%	9%	10%	10%	12%	13%	16%	19%	22%	25%
Interest Coverage	0.96	0.98	1.06	1.12	1.21	1.31	1.43	1.54	1.62	1.73
Capital Coverage	1.27	1.33	1.50	1.60	1.71	1.97	2.06	2.22	2.31	2.44

ELECTRIC OPERATIONS (PUB_MH_II_21b_CGAAP ASL with Salvage)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 295	2 598	2 727	2 167	2 237	2 441
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	235	252	275	296	296	288	262	230	200
	16 993	18 823	21 740	24 884	26 485	27 544	28 153	27 558	27 602	27 767
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 906	22 792	22 955	23 250	23 441
Current and Other Liabilities	2 016	2 151	2 096	3 068	2 211	2 649	2 596	2 093	2 011	2 079
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 735	2 777	2 825	2 714	2 577	2 380	2 155	1 956	1 825
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 823	21 740	24 884	26 485	27 544	28 153	27 558	27 602	27 767

ELECTRIC OPERATIONS (PUB_MH_II_21b_CGAAP ASL with Salvage)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823	42 952
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 384)	(17 200)	(18 031)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 710	24 666	24 623	24 921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 387	2 536	2 786	3 051	3 295	3 866	3 738	4 414	5 106	5 864
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	167	137	109	83	65	55	49	48	51	51
	27 707	27 847	28 077	28 305	28 522	29 044	28 895	29 552	30 256	31 091
LIABILITIES AND EQUITY										
Long-Term Debt	23 395	23 998	24 201	24 343	24 276	23 749	23 739	23 743	23 737	23 381
Current and Other Liabilities	2 082	1 605	1 509	1 398	1 370	1 970	1 245	1 201	1 135	1 448
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	1 771	1 746	1 832	1 992	2 266	2 677	3 224	3 883	4 619	5 457
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 707	27 847	28 077	28 305	28 522	29 044	28 895	29 552	30 256	31 091

ELECTRIC OPERATIONS (PUB_MH_II_21b_CGAAP ASL with Salvage)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	2 039	2 135	2 232	2 350	2 731	2 944	3 054	3 183
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(999)	(1 014)	(1 068)	(1 098)	(1 123)	(1 154)
Interest Paid	(511)	(514)	(547)	(593)	(785)	(928)	(1 222)	(1 349)	(1 329)	(1 340)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	587	571	599	483	443	471	525	618	705
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 600	1 590	600	560	580
Sinking Fund Withdrawals	110	21	-	7	448	204	294	716	165	26
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 470	933	573	243	284
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(245)	(262)	(358)	(252)	(258)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 516)	(1 830)	(1 302)	(1 144)	(980)	(985)
Net Increase (Decrease) in Cash	(270)	(77)	84	(52)	(20)	82	102	(46)	(120)	4
Cash at Beginning of Year	133	(137)	(214)	(130)	(182)	(202)	(119)	(17)	(63)	(183)
Cash at End of Year	(137)	(214)	(130)	(182)	(202)	(119)	(17)	(63)	(183)	(179)

ELECTRIC OPERATIONS (PUB_MH_II_21b_CGAAP ASL with Salvage)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 300	3 345	3 479	3 579	3 707	3 855	3 987	4 072	4 153	4 256
Cash Paid to Suppliers and Employees	(1 178)	(1 188)	(1 210)	(1 224)	(1 246)	(1 268)	(1 287)	(1 312)	(1 333)	(1 361)
Interest Paid	(1 349)	(1 349)	(1 350)	(1 364)	(1 367)	(1 351)	(1 337)	(1 246)	(1 225)	(1 194)
Interest Received	19	21	35	49	62	71	83	63	77	92
	792	829	954	1 040	1 157	1 308	1 447	1 578	1 673	1 793
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	390	580	190	190	(20)	170	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	296	103	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	254	203	161	163	(45)	178	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(270)	(269)	(278)	(290)	(302)	(311)	(320)	(298)	(309)	(320)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 045)	(1 051)	(1 056)	(1 061)	(1 091)	(1 085)	(1 133)	(1 124)	(1 182)	(1 274)
Net Increase (Decrease) in Cash	1	(19)	60	141	21	401	273	395	444	473
Cash at Beginning of Year	(179)	(178)	(197)	(138)	4	25	426	698	1 093	1 538
Cash at End of Year	(178)	(197)	(138)	4	25	426	698	1 093	1 538	2 011

CAMPUT

30 August 2013

Attention: Mr. Hans Hoogervorst
Chair, International Accounting Standards Board
30 Cannon Street
London EC4M6XH
United Kingdom

Dear Mr. Hoogervorst:

Re: Exposure Draft ED/2013/5 Regulatory Deferral Accounts

CAMPUT, Canada's Energy and Utility Regulators, appreciates this opportunity to respond to the International Accounting Standards Board's (the IASB's) Exposure Draft Regulatory Deferral Accounts (the "Exposure Draft" or "interim Standard").

CAMPUT consists of the following fourteen federal, provincial, territorial rate regulators of electricity and natural gas in Canada[1]:

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Manitoba Public Utilities Board
- National Energy Board
- New Brunswick Energy and Utilities Board
- Newfoundland & Labrador Board of Commissioners of Public Utilities
- Northwest Territories Public Utilities Board
- Nova Scotia Utility and Review Board
- Nunavut Utility Rates Review Council
- Ontario Energy Board
- Prince Edward Island - Island Regulatory and Appeals Commission
- Régie de l'énergie du Québec
- Saskatchewan Rate Review Panel
- Yukon Utilities Board

The objectives for the above regulatory bodies of electricity and gas sectors, among others, include protecting the interests of consumers with respect to prices and the adequacy, reliability and quality of services and promoting economic efficiency and cost effectiveness in the generation, transmission, and distribution of electricity, gas and oil. To serve the public interest and to maintain financial viability of the regulated companies are the key common, high-level objectives of the Canadian rate regulators. The Canadian rate regulators' comments in this document, unless otherwise specified, relate to rate-

[1] Some of the Canadian regulatory agencies also regulate oil pipelines, water and sewer utilities and other non-utility mandates.

regulated companies that are first time adopters of IFRS, since the scope of the Exposure Draft has been limited to these entities. Overall, all the Canadian rate regulators strongly support the interim Standard and the IASB's proposals contained in the Exposure Draft for regulatory deferral accounts. The Canadian rate regulators endorse the IASB's initiative to enable rate-regulated utilities to continue to recognize regulatory balances in their financial statements. The chairs of these regulatory commissions and boards have approved the contents of this comment letter and considered it very important that the interim Standard be put in place.

We are encouraged to observe that the IASB will permit rate-regulated utilities to apply financial accounting policies for financial reporting that are similar to those determined by rate regulators for the purposes of rate-making. We applaud the IASB's effort in developing the draft interim Standard to reduce uncertainty until the IASB completes its Comprehensive Rate-regulated accounting project**. It is our position that it would be a significant detriment to rate-regulated utilities in Canada, their rate-setting authorities, and their investors and financers if the interim Standard was not to be adopted in substantially the form proposed.** The reasons for our position to fully support the interim Standard are explained in the following paragraphs using the IASB's Effects Analysis, as outlined in the Exposure Draft. We have also provided additional comments in the Appendix to this letter in response to the ten questions from the IASB.

In evaluating the likely effects of permitting rate-regulated entities that are first-time adopters of IFRS to continue to recognize regulatory deferral account balances, IASB has considered the following factors in its Effects Analysis:[2]

a) How the proposed changes to the presentation of regulatory deferral account balances affect the financial statements of a rate-regulated entity.

We strongly endorse the IASB's statement "A number of rate-regulatory methodologies exist and, for each, application can vary by rate regulator, the entity that is being regulated and the particular circumstances. The objective of many methodologies is **to set 'just and reasonable' rates**, in other words, rates that balance both customer and investor interests. Rate regulators that use such methodologies establish rates that charge customers a fair price and are reasonably stable from year to year. At the same time, these rate regulators wish to ensure that the entity that is providing the regulated goods or services **remains financially viable**. Consequently, they may set rates to not only recover the costs of providing the goods or services, but also to provide a fair return to the entity's owners [emphasis added in bold]."[3]

We agree with the IASB that "regardless of the regulatory methodology that is used, the economic reality of an entity with operations that are subject to rate regulation is shaped in part by the actions of its rate regulator. By restricting prices, rate regulation can affect the amount and timing of the entity's revenues and cash flows, thereby affecting its financial position and performance."[4] We support the IASB's observation that "the nature and extent of rate regulation can have **a significant impact on the amount and timing of revenue and cash flows of a rate-regulated entity** [emphasis added in bold]".[5] We endorse the IASB's position that "discontinuing the recognition of regulatory deferral account

[2] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, paragraph BC70, page 45.
[3] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, paragraph BC23, page 33.
[4] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, paragraph BC27, page 34.
[5] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, paragraph BC66, page 44.

balances in advance of the comprehensive Rate-regulated Activities project could be a significant barrier to the adoption of IFRS for those entities for which **regulatory deferral account balances represent a significant proportion of net assets** [emphasis added in bold]".[6] As noted by the IASB, because of significant impact on the amount and timing of revenue and cash flows of a rate-regulated entity and because of significance of deferral account balances, rate regulators need to ensure the entity that is providing the regulated goods or services remains financially viable. This is part of the objective of setting just and reasonable rates for rate-regulated utilities. We note that IASB has acknowledged these considerations throughout the Exposure Draft as benefit drivers for developing the proposed interim Standard in order to remove a major barrier to the adoption of IFRS for many rate-regulated entities.[7,8]

The interim Standard resolves one major problem for entities with rate-regulated operations. Our observation is that, without the interim Standard, these rate-regulated entities will be required to provide two sets of financial statements, as has happened in some other jurisdictions and as was acknowledged by the IASB[9]: one to meet general purpose financial reporting requirements under IFRS; and, the other to present to the rate regulator for purpose of (i) requesting rate adjustments, (ii) regulatory accounting and rate-making, and (iii) regulatory reporting. As regulators, we find it unsatisfactory and not serving the public interest if there are two views of economic reality of entities with rate-regulated operations. Rate regulators are aware that their actions have significant economic impact, including investment, lending and consumer prices. The IASB has acknowledged that many of rate-regulated entities argue that recognizing such balances as assets and liabilities would provide more relevant information and would be a more representationally faithful way of reporting their rate-regulated activities.[10] Some of these utilities had to eliminate regulatory deferral account balances from the statement of financial position when they adopted IFRS and do not recognize such balances in IFRS financial statements. It behooves the accounting profession to find the appropriate ways to ensure all economic events are reflected in the base numbers reported in general purpose financial statements. Requiring rate-regulated entities to leave certain economic events outside the purview of the financial statements, or at best relegated to note disclosure, is not good enough for regulatory actions that affect prices. Furthermore, exclusion of certain economic events would not serve the needs of users of the financial statements.

Finally on this point, the results of having two views will add confusion and unnecessary complexity and higher cost to the rate-regulated entities and their customers such as maintaining two sets of books. Furthermore, the investors or the lenders of the rate-regulated entities will find it confusing to decide which set of financial statements to use when monitoring financial performance to judge the financial soundness of the enterprises. The IASB's proposed interim Standard addresses the above concerns. Therefore, we support the IASB's development and application of the interim Standard.

b) Whether those changes improve the comparability of financial information between different reporting periods for a rate-regulated entity and between different rate-regulated entities in a particular reporting period.

On this point, we fully support the IASB's views and reasons that the interim Standard will help achieve the following two stated IASB's objectives:

[6] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, paragraph BC15, page 31.
[7] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, paragraph BC20, page 32.
[8] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, paragraph BC70, page 45.
[9] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, paragraph BC84, page 48.
[10] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, paragraph BC10, page 30.

(a) "enhance the comparability of financial reporting by reducing barriers to the adoption of IFRS by entities with rate-regulated activities until guidance is developed through the IASB's comprehensive Rate-regulated Activities project; and

(b) ensure that users of financial statements will be able to identify clearly the amounts of regulatory deferral account balances, and movements in those balances, in order to be able to compare the financial statements of entities that recognize such balances in accordance with this [draft] interim Standard against the financial statements of entities that do not recognize such balances." [11]

Contrary to the views of Messrs. Gomes and Zhang, we believe that the objectives of general purpose financial reporting and regulatory reporting are not competing with each other; rather they are complementary, and therefore must be integrated to better serve the public interest and all users of the financial statements of entities with rate-regulated operations. The interim Standard will help bring the financial statements closer to the economic reality of the rate-regulated entities. We agree with the IASB that the interim Standard will improve the comparability between different reporting periods for a rate-regulated entity and between different rate-regulated entities in a particular reporting period. Our position is that IASB's proposed changes to recognize valuing and reporting regulatory deferral account balances not only enhance the comparability of information within the general financial statements, but also, they offer transparency of financial information to the users. Thus, the proposed changes by the IASB are vital to the credibility and usefulness of any financial statements that are prepared for the users.

c) Whether the changes will improve the quality of the financial information that is available to investors and its usefulness in assessing the future cash flows of a rate-regulated entity.

As one of the key users of financial statements, the lending and investment communities of the rate-regulated utilities will be most negatively impacted if regulatory deferral account balances are not recognized and reported in the rate-regulated utilities' financial statements.

Our position is that the IASB's interim Standard will improve the quality of the financial information that is available to investors and its usefulness in assessing the future cash flows of a rate-regulated entity. This is due to the fact that recognition of regulatory deferral accounts in the financial statements will increase transparency related to:

- "the amounts that the rate regulator decides are included as allowable costs when determining the customer rates and the amounts that eventually are recognized through the entity's statement of profit or loss and other comprehensive income for financial reporting purposes;"[12] and

- "all of the entity's expenditures that could have a significant effect on rates are usually subject to a prudency review by the rate regulator. This includes expenditures for the construction of property, plant and equipment and some intangible assets." [13]

[11] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, page 5.
[12] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, paragraph BC27, page 34.
[13] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, paragraph BC27(b), page 34.

We note that interim Standard states that "If a single cause has a significant effect on a regulatory deferral account balance, the entity shall disclose it separately"[14] and "when an entity concludes that a regulatory deferral account balance is no longer fully recoverable, it shall disclose that fact, the reason why it is not recoverable and the amount by which the regulatory deferral account balance has been reduced."[15] First, such transparency and availability of the financial information to lenders and investors will permit them to clearly note the facts, assess possible risks, and determine if the amounts reported in the financial statements are fairly and appropriately represented. Furthermore, having the financial information disclosed in financial statements is useful to investors and lenders because it provides them with a higher level of relevancy, reliability, and accuracy of information related to the recoverability of the amounts. Finally, transparency regarding financial information arising from rate-regulated activities will allow these users to make consistent apples to apples comparisons among these entities and make informed decisions.

We believe that the public interest is impaired by the fact that the transparency that exists today under current Generally Accepted Accounting Principles for these key users of the financial statements could be diminished in absence of the recognition of regulatory deferral accounts. Rate-regulated entities are capital intensive and require substantial financing. It is quite possible that a lack of transparency in how regulatory deferral account balances are reported and disclosed could lead to a higher risk assessment (lower credit rating) and therefore increased financing costs. This may further lead to higher costs to rate-regulated utilities, the lending and investing communities, and rate payers because of a false perception of increased risks.

d) Whether users will benefit from better economic decision-making as a result of improved financial reporting.

Rate regulation can significantly affect the economic environment of rate-regulated entities and their operations. The IASB has also noted this by stating "the nature and extent of rate regulation can have a significant impact on the amount and timing of revenue and cash flows of a rate-regulated entity. Hence, the IASB concluded that such disclosures should be part of the financial statements and that they could be given either in the financial statements or incorporated by cross-reference from the financial statements to some other statement that is available to users of the financial statements on the same terms as the financial statements and at the same time. IASB has also stated that this approach is consistent with certain risk disclosures required by IFRS 7 *Financial Instruments: Disclosures.*"[16]

We agree with the IASB that proposed changes and especially the improvements in comparability noted in paragraphs BC76–BC77, compared to the current IFRS standards will provide all users of financial statements including rate-regulated enterprises, the preparers of statements, the lenders and investors, the regulator, and the rate payers with relevant and reliable information to help them better understand the impact of rate regulation on rate-regulated entities and make informed decisions. The interim Standard can help improve the communication of relevant information for users of financial statements, rather than leaving it to the users to identify the nature and extent that rate-regulation can have on the amount and timing of revenue and cash flows arising from rate-regulated entities' activities. As the economic rate regulators who use and rely on the audited financial statements, we recognize the

[14] Draft International Financial Reporting Standard - Regulatory Deferral Accounts, paragraph 28, page 16.
[15] Draft International Financial Reporting Standard - Regulatory Deferral Accounts, paragraph 33, page 17.
[16] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, paragraph BC66, page 44.

significance of the interim Standard to our rate making decision process. In the absence of regulatory deferral accounts under IFRS, the interim Standard will provide temporary relief to enable the public to discern that the Regulators have set just and reasonable rates for rate-regulated entities, and monitor their financial performance.

e) The likely effect on compliance costs for preparers, both on initial application and on an ongoing basis; and whether the likely costs of analysis for users are affected.

IASB has rightfully determined that the likely effect of these proposals on the costs of analysis for users of financial statements is expected to be outweighed by the benefits of improved reporting. It stated that the proposals should have little or no impact on the net assets or on the net profit reported in the financial statements of those entities within the scope of the draft interim Standard.[17]

In summary, we support the IASB's decision to prioritize the issues related to rate-regulated activities through the interim Standard. We believe that the IASB's proposed interim Standard begins to address our concerns and resolves the uncertainty and apparent exclusion of rate-regulated activities from IFRS compliant financial statements that would otherwise occur. We view the IASB's interim Standard as a means to align financial reporting with the regulatory rate-making and regulatory accounting and reporting.

Attached are our responses to the questions in the invitation to comment. If you require any further information, please contact me at the telephone number below or at rochefort@camput.org.

Yours very truly,

Terry Rochefort
Executive Director, CAMPUT
Telephone: +1 905 827-5139

[17] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, paragraph BC72, page 46.

Appendix: Response to Questions in the Exposure Draft

Question 1
The Exposure Draft proposes to restrict the scope to those first-time adopters of IFRS that recognised regulatory deferral account balances in their financial statements in accordance with their previous GAAP.

Is the scope restriction appropriate? Why or why not?

We support the IASB's approach. However, we encourage the IASB to extend the scope of the interim Standard to all rate-regulated entities to recognize regulatory deferral account balances in IFRS financial statements for increased transparency, comparability, consistency, and relevancy of the information to the users of the financial statements. We note that this is especially important when the comprehensive Rate-regulated Activities project is completed.

Question 2
The Exposure Draft proposes two criteria that must be met for regulatory deferral accounts to be within the scope of the proposed interim Standard. These criteria require that:

(a) an authorised body (the rate regulator) restricts the price that the entity can charge its customers for the goods or services that the entity provides, and that price binds the customers; and
(b) the price established by regulation (the rate) is designed to recover the entity's allowable costs of providing the regulated goods or services (see paragraphs 7 -8 and BC33-BC34).

Are the scope criteria for regulatory deferral accounts appropriate? Why or why not?

We agree with the scope criteria for regulatory deferral accounts.

Question 3
The Exposure Draft proposes that if an entity is eligible to adopt the [draft] interim Standard it is permitted, but not required, to apply it. If an eligible entity chooses to apply it, the entity must apply the requirements to all of the rate-regulated activities and resulting regulatory deferral account balances within the scope. If an eligible entity chooses not to adopt the [draft] interim Standard, it would derecognise any regulatory deferral account balances that would not be permitted to be recognised in accordance with other Standards and the Conceptual Framework (see paragraphs 6, BC11 and BC49).

Do you agree that adoption of the [draft] interim Standard should be optional for entities within its scope? If not, why not?

We support the IASB's approach. However, we encourage the IASB to require all rate-regulated entities to apply the requirements to all of the rate-regulated activities and resulting regulatory deferral account balances within the scope for increased consistency, transparency, and comparability. This is an important consideration as our assessment is it is more likely than not that rate-regulated utilities in

Canada will choose to adopt the proposed interim Standard and continue to recognize regulated assets and liabilities.

Question 4
The Exposure Draft proposes to permit an entity within its scope to continue to apply its previous GAAP accounting policies for the recognition, measurement and impairment of regulatory deferral account balances. An entity that has rate-regulated activities but does not, immediately prior to the application of this [draft] interim Standard, recognise regulatory deferral account balances shall not start to do so (see paragraphs 14–15 and BC47–BC48).

Do you agree that entities that currently do not recognise regulatory deferral account balances should not be permitted to start to do so? If not, why not?

We agree that entities that have not adopted IFRS and currently do not recognize regulatory deferral balances should not be permitted to start to do so. This is important given the proposed Standard is intended to be applicable only as a short-term interim solution until the comprehensive Rate-regulated Activities project is completed.

Question 5
The Exposure Draft proposes that, in the absence of any specific exemption or exception contained within the [draft] interim Standard, other Standards shall apply to regulatory deferral account balances in the same way as they apply to assets and liabilities that are recognised in accordance with other Standards (see paragraphs 16–17, Appendix B and paragraph BC51).

Is the approach to the general application of other Standards to the regulatory deferral account balances appropriate? Why or why not?

Yes, we agree with the IASB's approach.

Question 6
***The Exposure Draft proposes that an entity should apply the requirements of all other Standards before applying the requirements of this [draft] interim Standard. In addition, the Exposure Draft proposes that the incremental amounts that are recognised as regulatory deferral account balances and movements in those balances should then be isolated by presenting them separately from the assets, liabilities, income and expenses that are recognised in accordance with other Standards (see paragraphs 6,
18–21 and BC55–BC62).***

Is this separate presentation approach appropriate? Why or why not?

Yes, we agree with the IASB's approach.

Question 7
The Exposure Draft proposes disclosure requirements to enable users of financial statements to understand the nature and financial effects of rate regulation on the entity's activities and to identify

and explain the amounts of the regulatory deferral account balances that are recognised in the financial statements (see paragraphs 22–33 and BC65).

Do the proposed disclosure requirements provide decision-useful information? Why or why not? Please identify any disclosure requirements that you think should be removed from, or added to, the [draft] interim Standard.

Yes, we agree with the IASB's approach.

Question 8

The Exposure Draft explicitly refers to materiality and other factors that an entity should consider when deciding how to meet the proposed disclosure requirements (see paragraphs 22–24 and BC63–BC64).

Is this approach appropriate? Why or why not?

Yes, we agree with the IASB's approach.

Question 9

The Exposure Draft does not propose any specific transition requirements because it will initially be applied at the same time as IFRS 1, which sets out the transition requirements and relief available.

Is the transition approach appropriate? Why or why not?

Yes, we agree with the IASB's approach.

Question 10

Do you have any other comments on the proposals in the Exposure Draft?

Canada's adoption of IFRS for publicly accountable enterprises has led to a wide diversity and inconsistency of practices in terms of the financial accounting and regulatory accounting frameworks among Canadian rate-regulated entities. The non-recognition of regulatory assets and liabilities under IFRS has been a significant barrier to the adoption of IFRS by the majority of Canadian utilities. The effective date for adoption of IFRS in Canada was January 1, 2011. However, four extensions to the mandatory IFRS adoption have been granted by the Canadian Accounting Standards Board (AcSB) to rate-regulated entities. The current extension date granted for mandatory changeover to the IFRS is as at January 1, 2015. To date, less than 10% of rate-regulated utilities in Canada have adopted IFRS. Most rate-regulated utilities have remained under current Canadian GAAP. There are certain rate-regulated entities that have been granted approval by their rate regulators to use US GAAP for regulatory rate-making and reporting purposes. These entities have received permission to use US GAAP for financial reporting purposes effective January 1, 2012 through to December 31, 2014. It is likely that most these utilities would seek to remain under US GAAP if regulatory assets and liabilities are not approved by the IASB. Furthermore, there are a number of large Canadian electricity utilities that are owned by provincial governments and are required to use US GAAP effective January 1, 2012 through regulations that were issued by these governments.

IFRS may not be required by the AcSB or the Canadian Public Sector Accounting Board (PSAB) for rate-regulated enterprises for whom some other standard may apply. For example, private enterprises that are not owned by the government and not listed on a public exchange may choose to use Accounting Standards for Private Enterprises (ASPE), which is similar to the old Canadian GAAP, for financial reporting purposes. An Ontario utility has received approval by the OEB to use ASPE for regulatory rate-making and reporting purposes. Its parent company operating in another province has received approval from its regulator to use US GAAP. This has led to reduced comparability among rate-regulated utilities for users of financial statements. The transition to IFRS in Canada has led to divergence in practices with respect to rate-making, regulatory accounting, and financial reporting among Canadian rate-regulated entities. We believe that the interim Standard will help reduce this divergence and facilitate future convergence and comparability among rate-regulated entities, including benchmarking, consistent reporting, etc. This will ultimately help rate regulators better serve the public interest and benefit all users of the general financial statements.

In its Exposure Draft, IASB has acknowledged that "in recent years there has been a trend among rate regulators towards applying incentive-based regulatory methodologies, such as so-called 'price-cap' regulation"[18] or "hybrid methodologies that are combinations of price-cap and cost-of-service approaches".[19] We would like to emphasize that the operation as well as regulatory accounting treatment and reporting of the regulatory deferral accounts are not affected by the methods used by rate regulators for establishing rates. This is due to the fact that it is still highly likely that the governments' policies and rate regulators' actions and initiatives may cause differences between the accounting treatment of a transaction or event for rate-setting purposes and its accounting treatment under IFRS (e.g., regulatory deferral accounts established for investment in renewable generation, smart grids, asset management, storm costs, etc.). The revenues and costs associated with these initiatives are subject to prudency review and approval of the rate regulators. Therefore, an interim Standard will still be required under all rate-regulatory regimes that regulators will use for setting just and reasonable rates. Furthermore, the application of interim Standard during any rate regulation regimen will help the transparency, comparability, and the relevancy of the information to the users of the financial statements.

[18] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, paragraph BC25, page 33.
[19] Exposure Draft – ED/2013/5, Regulatory Deferral Accounts, paragraph BC25, page 33.

Section:	Tab 5: Appendix 5.6 Appendix 11.49	Page No.:	PUB/MH I-37 (d)
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please indicate the source of Appendix 11.49 and who determined the sample asset group breakdowns.

b) Please indicate whether MH's auditors have reviewed the current ASL account groupings and the proposed accounting groupings set out in Appendix 11.49 and concluded they are compliant for financial reporting purposes?

c) Please describe what would be required to expand the account groupings under an IFRS-compliant ASL methodology, as well as the projected cost to do so.

RATIONALE FOR QUESTION:

This question explores the requirements to continue to use the ASL method of depreciation.

RESPONSE:

a) Appendix 11.49, Response to Public Utilities Board Order 43/13, Directives 8 & 9, was prepared by Manitoba Hydro with depreciation impact analysis prepared by Gannett Fleming. The sample asset breakdown was determined by Manitoba Hydro based on a review of the detailed information available in the current component group accounts in terms of materiality and different service lives, a review of utilities with a greater level of componentization than Manitoba Hydro (e.g. BC Hydro), as well as discussions with Gannett Fleming.

b) Manitoba Hydro's auditors Ernst & Young have reviewed the current ASL account groupings for financial reporting under CGAAP only. Given that Manitoba Hydro is moving to the ELG depreciation methodology for financial reporting purposes upon transition to IFRS, Manitoba Hydro has not requested its external auditors assess and conclude on whether the ASL asset component groupings as set out in Appendix 11.49 would be compliant with the requirements of IFRS.

c) Please see section 5.0, *Additional Componentization Requirements for Manitoba Hydro Using an IFRS Compliant ASL Method*, of Appendix 11.49 for a description of what would be required to expand the account groupings under an IFRS compliant ASL methodology, as well as examples of how some account groupings may be further componentized and the projected cost to do so. Please note that the $2 million cost as identified in Appendix 11.49 excludes the ongoing administrative costs associated with having to maintain asset records at a lower level of componentization. Such ongoing costs include, an increased number of cost allocation transactions, additional asset retirement processing, additional components for review when conducting depreciation studies, among others.

Section:	Tab 5	**Page No.:**	PUB/MH I-38 i-xii
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

Several of the accounts' only adjustment from the 2014 ASL depreciation rate to an IFRS compliant ELG rate is the removal of the net salvage provision.

QUESTION:

a) Please provide the same analysis provided in PUB/MH-I-38 i-xii for the 20 account groupings that have the largest impact on increasing depreciation expense arising from the proposed transition from ASL to ELG.

b) Please indicate the number of account groupings where the only difference between ASL and proposed ELG is the removal of net salvage from the rate. In these cases please explain whether the rate would be considered an IFRS compliant ASL methodology rate.

RATIONALE FOR QUESTION:

To understand the implications of changing from ASL to ELG for rate setting purposes.

RESPONSE:

a) Please see the following pages for the 20 account groupings that have the largest impact on increasing depreciation expense arising from the proposed transition from CGAAP ASL to ELG. The account groupings are arranged starting with the largest impact (ASL to ELG) through to the smallest.

b) The "amortization" accounts as listed in the 2014 Depreciation Study on page III-5 of Attachment 2 of Appendix 5.6 will have the same depreciation expense under both the CGAAP ASL and ELG methods when the net salvage impact is removed from the

ASL rates. Manitoba Hydro considers these rates to be IFRS compliant. Ernst & Young will not be in a position to opine on this assertion until they perform the necessary audit procedures.

1.

Distribution - Overhead Conductor and Devices (000's)	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**1.98%**			
Adjustment to annual true-up	0.26%	$ 1,850	$ 1,915	$ 1,984
2014-15 Approved ASL Rate	**2.24%**			
Removal of net salvage on transition to IFRS	(0.84%)		(6,129)	(6,314)
Change from ASL to ELG	0.40%		2,957	3,072
2015-16 Approved ELG Rate	**1.80%**			
Net Impact of Changes		**$ 1,850**	**$ (1,258)**	**$ (1,258)**

For the 2014 Depreciation Study, the true-up position was adjusted from ($2.0) million to ($0.5) million due to the change from simulated vintaging to new vintage estimates for this account. The new estimated vintaging was based on recently gathered operational data for aged distribution poles which indicated the population was older than expected and as such, the true-up position was adjusted accordingly. There was a slight change in the IOWA curve from 60-R2 to 60-R1.5. The impact of the removal of negative salvage is significant given the 38% negative salvage factor on this account.

2.

Distribution - Poles and Fixtures (000's)	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**2.10%**			
Change in average service life	(0.38%)	$ (2,611)	$ (2,748)	$ (2,902)
Adjustment to annual true-up	0.24%	1,652	1,743	1,846
2014-15 Approved ASL Rate	**1.96%**			
Removal of net salvage on transition to IFRS	(0.76%)		(5,526)	(5,807)
Change from ASL to ELG	0.38%		2,837	3,007
2015-16 Approved ELG Rate	**1.58%**			
Net Impact of Changes		**$ (959)**	**$ (3,693)**	**$ (3,857)**

For the 2014 Depreciation Study, vintages were revised from those used in the 2010 study. The updated service lives and true-up position take into consideration recently gathered operational data which indicates that, as a result of Manitoba Hydro’s various pole maintenance programs, wood poles are lasting longer than previously expected and as such, the average service life of wood poles was increased from 55 to 65 years. The IOWA curve changed from a 55-R3 to a 65-S0.5 curve. The impact of the removal of negative salvage is significant given the 38% negative salvage factor on this account.

3.

Hydro Generation - Turbines and Generators (000's)	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**1.72%**			
Change in average service life	0.21%	$ 2,341	$ 2,353	$ 2,423
2014-15 Approved ASL Rate	**1.93%**			
Removal of net salvage on transition to IFRS	(0.27%)		(3,175)	(3,249)
Change from ASL to ELG	0.14%		1,688	1,685
2015-16 Approved ELG Rate	**1.80%**			
Net Impact of Changes		**$ 2,341**	**$ 865**	**$ 858**

For the 2014 Depreciation Study, the service life of turbines and generators was decreased from 65 to 60 years resulting in an overall increase in the depreciation rate. The reduction in the service life is consistent with historical retirement patterns for this account and remains in the range of average service life estimates of the Canadian peer group. The IOWA curve changed from a 65-S3 to a 60-S3 curve.

4.

Substation - Power Transformers (000's)	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**2.21%**			
Adjustment to annual true-up	0.21%	$ 771	$ 772	$ 773
2014-15 Approved ASL Rate	**2.44%**			
Removal of net salvage on transition to IFRS	(0.44%)		(1,459)	(1,449)
Change from ASL to ELG	0.43%		1,449	1,455
2015-16 Approved ELG Rate	**2.43%**			
Net Impact of Changes		**$ 771**	**$ 763**	**$ 779**

For the 2014 Depreciation Study, the true-up position was adjusted from ($0.2) million to $0.5 million due to the change from statistically simulated vintaging to actual vintaging for this account. Actual vintages were based on a detailed review of information available in various operational systems. The changes to actual vintages resulted in a slight change in the IOWA curve from a 50-R2 to a 50-R1.5 curve for the 2014 study.

5.

Substation - Electronic Equipment and Batteries (000's)	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**4.76%**			
Change in average service life	(0.95%)	$ (2,096)	$ (2,075)	$ (2,055)
2014-15 Approved ASL Rate	**3.81%**			
Removal of net salvage on transition to IFRS	(0.53%)		(1,173)	(1,173)
Change from ASL to ELG	0.62%		1,361	1,352
2015-16 Approved ELG Rate	**3.90%**			
Net Impact of Changes		**$ (2,096)**	**$ (1,887)**	**$ (1,876)**

Based on the retirement pattern for this account, the average service life was increased from 20 to 25 years for the 2014 Depreciation study. The IOWA curve was changed from a 20-R2 to a 25-R2 for the 2014 study.

6.

Substation - Other Station Equipment (000's)	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**2.54%**			
Change in average service life	(0.07%)	$ (387)	$ (386)	$ (385)
2014-15 Approved ASL Rate	**2.47%**			
Removal of net salvage on transition to IFRS	(0.49%)		(2,695)	(2,682)
Change from ASL to ELG	0.22%		1,216	1,213
2015-16 Approved ELG Rate	**2.20%**			
Net Impact of Changes		**$ (387)**	**$ (1,866)**	**$ (1,854)**

The average service life for this account was increased from 43 to 45 years based on the retirement pattern analyzed in the 2014 Depreciation Study. The IOWA curve was changed from a 43-R2 to a 45-R3 for the 2014 study.

7.

Distribution Underground Cable and Devices - Primary (000's)	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**1.69%**			
Adjustment to annual true-up	0.01%	$ 38	$ 39	$ 40
2014-15 Approved ASL Rate	**1.70%**			
Removal of net salvage on transition to IFRS	(0.10%)		(364)	(353)
Change from ASL to ELG	0.23%		909	936
2015-16 Approved ELG Rate	**1.83%**			
Net Impact of Changes		**$ 38**	**$ 585**	**$ 623**

For the 2014 Depreciation Study, the IOWA curve was changed slightly from a 60-R4 to a 60-R3 curve to better align with the results of the study. The change in the IOWA curve resulted in a small change to the true-up position.

8.

Communication - Carrier Equipment (000's)	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**7.68%**			
Change in average service life	(2.94%)	$ (3,723)	$ (3,679)	$ (3,658)
2014-15 Approved ASL Rate	**4.74%**			
Removal of net salvage on transition to IFRS	(0.40%)		(503)	(504)
Change from ASL to ELG	0.56%		702	698
2015-16 Approved ELG Rate	**4.90%**			
Net Impact of Changes		**$ (3,723)**	**$ (3,480)**	**$ (3,464)**

The Carrier equipment account was a new account for the 2010 Depreciation Study identified during the componentization process. As a result of the retirement pattern for this account in addition to discussions with operations personnel, the average service life was increased from 15 to 20 years for the 2014 Depreciation Study resulting in a significant decrease in the true up position from $0.8 million to ($0.6) million and in the annual depreciation rate.

9.

Brandon Units 6 and 7 Combustion Turbine (000's)	Depreciation Rate	Depreciation Expense Impact 2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**4.05%**			
Adjustment to annual true-up	(0.18%)	$ (258)	$ (258)	$ (258)
2014-15 Approved ASL Rate	**3.87%**			
Removal of net salvage on transition to IFRS	(0.69%)		(989)	(989)
Change from ASL to ELG	0.48%		688	688
2015-16 Approved ELG Rate	**3.66%**			
Net Impact of Changes		**$ (258)**	**$ (559)**	**$ (559)**

The small change from the 2010 Depreciation Study resulted from regular additions and retirement activity for this account. No changes were made to the estimated average service life or IOWA curve.

10.

Communication - Fibre Optic and Metallic Cable (000's)	Depreciation Rate	Depreciation Expense Impact 2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**3.06%**			
Adjustment to annual true-up	0.06%	$ 79	$ 80	$ 81
2014-15 Approved ASL Rate	**3.12%**			
Removal of net salvage on transition to IFRS	(0.15%)		(199)	(201)
Change from ASL to ELG	0.48%		640	646
2015-16 Approved ELG Rate	**3.45%**			
Net Impact of Changes		**$ 79**	**$ 520**	**$ 525**

The adjustment to the annual true-up position for this account is the result of a slight change to the IOWA curve from a 35-R1.5 to a 35-R2.5 curve to better align with the results of the 2014 study.

11.

Substation - Converter Equipment HVDC (000's)	Depreciation Rate	Depreciation Expense Impact 2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**4.13%**			
Change in average service life	(0.91%)	$ (4,135)	$ (4,144)	$ (4,154)
2014-15 Approved ASL Rate	**3.22%**			
Removal of net salvage on transition to IFRS	(0.75%)		(3,416)	(3,424)
Change from ASL to ELG	0.14%		638	639
2015-16 Approved ELG Rate	**2.61%**			
Net Impact of Changes		**$ (4,135)**	**$ (6,923)**	**$ (6,938)**

The reduction in the depreciation rate from the 2010 Depreciation Study reflects both the change in the average service life from 25 to 30 years, as based on the retirement pattern for this account, and the change to the IOWA curve from a 25-R3 to a 30-S4 curve to better align with the statistical study. The impact of the removal of negative salvage is significant given the 15% negative salvage factor on this account.

12.

Distribution - Serialized Equipment Overhead (000's)	Depreciation Rate	Depreciation Expense Impact 2014-15	2015-16	2016-17
2014-15 Previous ASL Rate	**2.86%**			
Change in average service life	(0.58%)	$ (1,248)	$ (1,333)	$ (1,420)
2014-15 Approved ASL Rate	**2.28%**			
Removal of net salvage on transition to IFRS	(0.44%)		(1,002)	(1,062)
Change from ASL to ELG	0.26%		603	645
2015-16 Approved ELG Rate	**2.10%**			
Net Impact of Changes		**$ (1,248)**	**$ (1,733)**	**$ (1,837)**

The reduction in the annual depreciation rate reflects an increase in the estimated service life for this account from 35 to 45 years which is consistent with the historical experience for this asset and reflective of discussions with operational staff. The IOWA curve was changed for this account from a 35-R3 to a 45-R3 curve to better align with the results of the study.

13.

Hydro Generation - Spillway (000's) *excludes Pointe du Bois depreciation results*	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**1.44%**			
Change in average service life	(0.06%)	$ (252)	$ (252)	$ (252)
2014-15 Approved ASL Rate	**1.38%**			
Removal of net salvage on transition to IFRS	(0.19%)		(695)	(660)
Change from ASL to ELG	0.15%		584	590
2015-16 Approved ELG Rate	**1.34%**			
Net Impact of Changes		**$ (252)**	**$ (362)**	**$ (322)**

The reduction in the depreciation rate reflects the change in the average service life from 75 to 80 years based on the continued trend of limited retirement experience for this account, as well as affirmation by operational staff that the spillway lives are expected to last longer than the previous 75 year average life estimate. The IOWA curve was changed for this account from a 75-R2 curve to an 80-R3 curve to better align with the results of the study. This analysis excludes the original Pointe du Bois spillway which is subject to end of life accounting as it is expected to be decommissioned in October 2015, consistent with the advancement of the final in-service date for the Pointe du Bois spillway replacement project. Please refer to PUB/MH I-38 (ii) for an analysis of the changes to the depreciation rate for the original Point du Bois spillway.

14.

Distribution - Serialized Equipment Underground (000's)	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**2.62%**			
Change in average service life	(0.02%)	$ (41)	$ (43)	$ (44)
2014-15 Approved ASL Rate	**2.60%**			
Removal of net salvage on transition to IFRS	(0.47%)		(988)	(1,006)
Change from ASL to ELG	0.27%		583	603
2015-16 Approved ELG Rate	**2.40%**			
Net Impact of Changes		**$ (41)**	**$ (447)**	**$ (446)**

The reduction in the annual depreciation rate reflects a small increase in the estimated service life for this account from 40 to 42 years consistent with the historical experience for this asset. The IOWA curve was changed slightly for this account from a 40-R3 to a 42-R3 curve to better align with the results of the statistical study.

15.

Substation - Interrupting Equipment (000's)	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**2.41%**			
Change in average service life	0.11%	$ 230	$ 232	$ 234
2014-15 Approved ASL Rate	**2.52%**			
Removal of net salvage on transition to IFRS	(0.47%)		(982)	(985)
Change from ASL to ELG	0.26%		551	557
2015-16 Approved ELG Rate	**2.31%**			
Net Impact of Changes		**$ 230**	**$ (199)**	**$ (194)**

For the 2014 Depreciation Study, the estimated average service life for this account increased from 45 to 50 years and the true-up position was adjusted from ($0.2) million to $0.5 million due to the change from statistically simulated vintaging to new vintage estimates developed as part of Manitoba Hydro's preparation for asset conversion to IFRS whereby a detailed review of information available in various operational systems was performed. The IOWA curve was changed for this account from a 45-R2 curve to a 50-R2.5 curve to better align with the results of the study.

16.

Hydro Generation Auxiliary Station Processes (000's)	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**2.63%**			
Change in average service life	(0.67%)	$ (1,007)	$ (1,019)	$ (1,023)
2014-15 Approved ASL Rate	**1.96%**			
Removal of net salvage on transition to IFRS	(0.28%)		(421)	(432)
Change from ASL to ELG	0.36%		538	545
2015-16 Approved ELG Rate	**2.04%**			
Net Impact of Changes		**$ (1,007)**	**$ (903)**	**$ (910)**

The annual depreciation rate for this account is reduced due to an increase in the estimated service life for this account from 40 to 50 years consistent with the historical experience for this asset. The IOWA curve was changed for this account from a 40-R2.5 curve to a 50-R2 curve to better align with the results of the study.

17.

Distribution U/G Cable & Devices - Secondary (000's)	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**2.21%**			
Change in average service life	0.06%	$ 143	$ 148	$ 153
2014-15 Approved ASL Rate	**2.27%**			
Removal of net salvage on transition to IFRS	(0.15%)		(364)	(373)
Change from ASL to ELG	0.19%		469	486
2015-16 Approved ELG Rate	**2.31%**			
Net Impact of Changes		**$ 143**	**$ 253**	**$ 266**

The annual depreciation rate for this account has increased slightly due to a decrease in the estimated service life for this account from 45 to 44 years consistent with the historical experience for this asset. The IOWA curve was changed for this account from a 45-R4 curve to a 44-S3 curve to better align with the results of the study.

18.

Substation Accessory Stn Equipment HVDC System (000's)	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**2.85%**			
Change in average service life	0.13%	$ 215	$ 217	$ 219
2014-15 Approved ASL Rate	**2.98%**			
Removal of net salvage on transition to IFRS	(0.58%)		(969)	(978)
Change from ASL to ELG	0.27%		451	455
2015-16 Approved ELG Rate	**2.67%**			
Net Impact of Changes		**$ 215**	**$ (301)**	**$ (303)**

The annual depreciation rate for this account has increased due to a decrease in the estimated service life for this account from 37 to 36 years consistent with the historical experience for this asset. The IOWA curve was changed for this account from a 37-R4 to a 36-R3 curve to better align with the results of the study.

19.

Substation Other Transformers - AC (000's)	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**3.09%**			
Change in average service life	(0.80%)	$ (852)	$ (872)	$ (891)
2014-15 Approved ASL Rate	**2.29%**			
Removal of net salvage on transition to IFRS	(0.43%)		(464)	(473)
Change from ASL to ELG	0.40%		437	447
2015-16 Approved ELG Rate	**2.26%**			
Net Impact of Changes		**$ (852)**	**$ (899)**	**$ (917)**

For the 2014 Depreciation Study, the estimated average service life for this account increased from 35 to 50 years and the true-up position was adjusted from ($0.2) million to $0.5 million due to the change from statistically simulated vintaging to actual vintaging for this account. Actual vintaging was determined from a detailed review of information available in various operational systems. The IOWA curve was changed for this account from a 35-R2 curve to a 50-S1 curve to better align with the results of the study.

20.

Hydro Generation A/C Eletrcial Power Systems (000's)	**Depreciation Rate**	**Depreciation Expense Impact 2014-15**	**2015-16**	**2016-17**
2014-15 Previous ASL Rate	**2.19%**			
Change in average service life	(0.24%)	$ (768)	$ (768)	$ (767)
2014-15 Approved ASL Rate	**1.95%**			
Removal of net salvage on transition to IFRS	(0.29%)		(1,000)	(999)
Change from ASL to ELG	0.13%		422	422
2015-16 Approved ELG Rate	**1.79%**			
Net Impact of Changes		**$ (768)**	**$ (1,345)**	**$ (1,344)**

For the 2014 Depreciation Study, the depreciation rate was reduced as the estimated average service life for this account increased from 50 to 55 years based on the retirement experience to date. The IOWA curve for this account was changed from a 50-R3 to a 55-R4 curve to better align with the results of the study.

Section:	Tab 5 Appendix 5.6	**Page No.:**	PUB/MH I-39a & b
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	ASL vs ELG		

PREAMBLE TO IR (IF ANY):

MH has indicated that the 2014 ASL depreciation schedules were not supported by a stand-alone depreciation study and that the excerpt schedules were provided for illustrative purposes.

QUESTION:

a) Please file any supporting memos or presentations made by Gannett Fleming related to the 2014 ASL study results to support the changes made in ASL 2014 depreciation rates.

b) Please revise the table in response to PUB/MH I-39 (b) to include columns for the 2014 ASL rate without net salvage and also the annual accrual amount determined on that basis.

RATIONALE FOR QUESTION:

To determine the impact of retaining the ASL methodology for rate-setting purposes.

RESPONSE:

a) The underlying reasons supporting the change in service life estimates in the ASL study are those documented in the 2014 ELG Depreciation study provided in Attachment 2 of Appendix 5.6 of the Application. Gannett Fleming did not provide any other supporting memos or presentations related to the 2014 ASL study.

b) The following chart provides an updated table from response PUB/MH-I-39b including columns for the 2014 ASL rate without net salvage and the annual accrual amount determined on that basis.

MANITOBA HYDRO - ELECTRIC OPERATIONS
SUMMARY OF COST BASE, ACCRUAL PERCENTAGES AND AMOUNTS
ASL BALANCES

Plant Group	2010 Study Original Cost Base	2010 Study ASL Rate*	Annual Accrual $'s	2014 Study Original Cost Base	2014 Study ASL Rate*	Annual Accrual $'s	2014 Study ASL No Salvage Rate*	Annual Accrual $'s
Generation								
Hydro	**4,716,467,183**	1.48%	69,582,773	**5,445,593,386**	1.65%	89,705,854	1.45%	79,039,763
Thermal	**430,613,460**	3.44%	14,792,480	**439,575,329**	3.47%	15,270,747	3.23%	14,192,748
Diesel	**44,622,878**	2.42%	1,078,029	**48,030,666**	3.84%	1,845,608	3.64%	1,749,073
Transmission	**756,206,167**	1.71%	12,937,797	**980,402,254**	1.58%	15,467,630	1.19%	11,669,992
Substations	**2,446,844,172**	3.16%	77,232,743	**2,975,185,020**	2.71%	80,566,444	2.19%	65,120,918
Distribution	**2,378,666,825**	2.41%	57,294,240	**2,875,373,143**	2.24%	64,290,076	1.67%	48,130,519
General	**1,294,317,255**	6.18%	79,938,315	**1,466,265,753**	5.13%	75,266,372	5.03%	73,771,276
Total Plant In Service	**12,067,737,940**	**2.59%**	**312,856,377**	**14,230,425,551**	**2.41%**	**342,412,731**	**2.06%**	**293,674,289**

* Please note these rates are not IFRS compliant

Section:	Tab 5: Appendix 5.6 Attachment 2	Page No.:	PUB/MH I-40a, b
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	Impact on Revenue Requirement of use of ASL vs ELG		

PREAMBLE TO IR (IF ANY):

The analysis in PUB/MH I-40 b appears to show that depreciation expense would be higher under ASL in 2021/22 than using ELG.

QUESTION:

Please refile the analysis by removing net salvage from the calculated depreciation costs and providing a comparison between ELG and the adjusted ASL rates.

RATIONALE FOR QUESTION:

To understand the implications for rate-setting purposes of using ASL rates rather than ELG as proposed by MH.

RESPONSE:

The following table provides a summary of the forecast average Property, Plant and Equipment in service, and a comparison of the associated depreciation expense for the 2021/22 fiscal year calculated using ELG no Salvage (IFRS) and CGAAP ASL no Salvage depreciation rates. Please note that the depreciation associated with the WPLP is not included in either Appendix 5.6, Attachment 2, page vii, or this response. Please also note that the CGAAP ASL no Salvage depreciation figures provided in this response are not IFRS compliant. In addition, please see the response to PUB/MH-II-21b and PUB/MH II-21c for a discussion regarding the impacts associated with using the CGAAP ASL method of depreciation for rate-setting purposes.

PLANT GROUP	FORECAST AVERAGE PLANT IN SERVICE 2021/22 $ 000's	FORECAST DEPRECIATION EXPENSE ELG NO SALVAGE (IFRS) 2021/22 %'s	$ 000's	FORECAST DEPRECIATION EXPENSE CGAAP ASL NO SALVAGE 2021/22 %'s	$ 000's	DIFFERENCE IN FORECAST DEPRECIATION EXPENSE ELG VS. CGAAP ASL (NO SALVAGE) 2021/22 %'s	$ 000's
MANITOBA HYDRO							
Generation							
Hydro	$ 7 950 831	1.59	$ 126 084	1.49	$ 118 796	0.09	$ 7 288
Thermal	452 862	3.40	15 414	3.19	14 467	0.21	947
Diesel	52 650	3.34	1 756	2.93	1 544	0.40	212
Transmission	3 516 821	1.28	45 093	1.11	39 087	0.17	6 006
Substations	7 122 683	2.37	168 690	2.16	153 510	0.21	15 180
Distribution	4 266 096	2.01	85 614	1.72	73 394	0.29	12 220
General	1 991 241	5.06	100 726	4.82	95 954	0.24	4 772
Manitoba Hydro - Total Plant in Service	**$ 25 353 184**	**2.14**	**$ 543 377**	**1.96**	**$ 496 752**	**0.18**	**$ 46 625**
KEEYASK HYDROPOWER LIMITED PARTNERSHIP							
Generation							
Hydro	6 048 540	1.33	80 628	1.22	73 566	0.12	7 062
Transmission	19 839	1.36	270	1.24	246	0.12	24
Substations	21 294	1.36	290	1.24	264	0.12	26
Distribution	2 467	1.38	34	1.26	31	0.12	3
KHLP - Total Plant in Service	**$ 6 092 140**	**1.33**	**$ 81 222**	**1.22**	**$ 74 107**	**0.12**	**$ 7 115**
Total Plant in Service	**$ 31 445 324**	**1.99**	**$ 624 599**	**1.82**	**$ 570 859**	**0.17**	**$ 53 740**

* The CGAAP ASL no Salvage depreciation figures provided in this schedule are not IFRS compliant.

Section:	Tab 5: Appendix 5.7	**Page No.:**	PUB/MH I-41c
Topic:	Finance Results & Forecasts		
Subtopic:	Depreciation Expense		
Issue:	Changes in 2014 Depreciation Study		

PREAMBLE TO IR (IF ANY):

MH will be restating 2014/15 for comparative accounting purposes when it transitions to IFRS. This would include removal of the impact of net salvage from depreciation rates in that year which appears to increase retained earnings on transition by $57 million. This $57 million in additional depreciation expense is included in MH's requested 2014/15 revenue requirement. The adjustment is reflected in 2016 on Schedule B Appendix 5.7 page 5 but appears to relate to the prior year.

QUESTION:

a) Please indicate the implications on retained earnings if MH were to retroactively restate the removal of net salvage as part of an accounting policy change.

b) Please confirm there would be a $57 million impact of such a retroactive restatement.

c) Please discuss the implications for financial reporting purposes if, for rate-setting purposes, the net salvage were removed for 2014/15. How would this adjustment impact future financial reporting?

RATIONALE FOR QUESTION:

To assess the impact of an alternate approach to net salvage costs.

RESPONSE:

a) As outlined in the response to PUB/MH-I-41c, the removal of net salvage from depreciation rates in fiscal 2014/15 under CGAAP would be considered a change in accounting policy and would require retrospective treatment (i.e. an adjustment to the April 1, 2014 retained earnings for prior years' net salvage amounts) going back as far as Manitoba Hydro's records would permit. Manitoba Hydro understands that such an adjustment would be inconsistent with past decisions of the PUB. The PUB found on page 18 of Order 43/13, "*The Board also accepts Manitoba Hydro's position that net salvage should be removed from depreciation rates when International Financial Reporting Standards are implemented rather than during the test years*".

Removing net salvage from depreciation rates upon Manitoba Hydro's transition to IFRS April 1, 2015 is allowed prospective accounting treatment as IFRS permits a rate regulated entity to carry forward the net book value of its property, plant & equipment upon transition to IFRS. MH14 assumes a $57 million increase to the April 1, 2015 retained earnings balance of Manitoba Hydro upon its transition to IFRS in recognition of the of the 2014/15 IFRS adjustments.

b) Not confirmed. Depreciation expense would decrease by $57 million in fiscal 2014/15 if Manitoba Hydro were to make an accounting policy change in 2014/15, however, as noted in the response to part (a) above, a retrospective adjustment to retained earnings would be required for the hundreds of millions of dollars of net salvage recorded in the years prior to 2014/15.

c) If, the PUB determined that net salvage was to be removed from depreciation expense for rate-setting purposes for 2014/15, Manitoba Hydro would need to assess the financial reporting implications under CGAAP as Manitoba Hydro's 2014/15 financial statements will have been finalized and approved by the MHEB.

In addition, as Manitoba Hydro is required to restate its 2014/15 financial statements, the impacts under IFRS of such an order would also have to be determined. The financial reporting implications under both CGAAP and IFRS would need to be confirmed with Manitoba Hydro's external auditors. Manitoba Hydro is also concerned that any retrospective accounting changes related to PP&E prior to the transition to IFRS may jeopardize Manitoba Hydro's ability to carry forward asset net book values on transition to IFRS.

Section:	Appendix 5.6	Page No.:	PUB/MH I-37(b)
Topic:	Finance Results & Forecasts		
Subtopic:	Depreciation Expense		
Issue:	Crossover Point for ALS or ELG		

PREAMBLE TO IR (IF ANY):

Until 2034, depreciation under ELG is consistently higher than under ALS, and the difference appears to be growing. The total difference appears to be $1.2 billion.

QUESTION:

Advise if and when there would be a "crossover" point at which time depreciation expense under ALS would be lower than under ELG, assuming net salvage is treated the same under both methodologies. Please explain.

RATIONALE FOR QUESTION:

To assess the impact of an alternate approach to net salvage costs.

RESPONSE:

Assuming net salvage is treated the same under both ELG and CGAAP ASL, the crossover point at which time depreciation expense under CGAAP ASL will be higher than depreciation expense under ELG will vary on an account by account basis as a result of changes to the demographics of the assets due to the timing and amount of actual asset additions and retirements. Such changes will be incorporated into future depreciation studies and will contribute to changes in depreciation rates.

In MH 14, the difference in depreciation expense between ELG and CGAAP ASL grows over the forecast period due to the continued level of capital investment. Although Manitoba Hydro expects to adjust depreciation rates approximately every five years, based on comprehensive depreciation studies, MH 14 does not attempt to predict future depreciation rate changes. As such, Manitoba Hydro is not certain as to the time period in which depreciation expense under CGAAP ASL will be higher than depreciation expense under ELG.

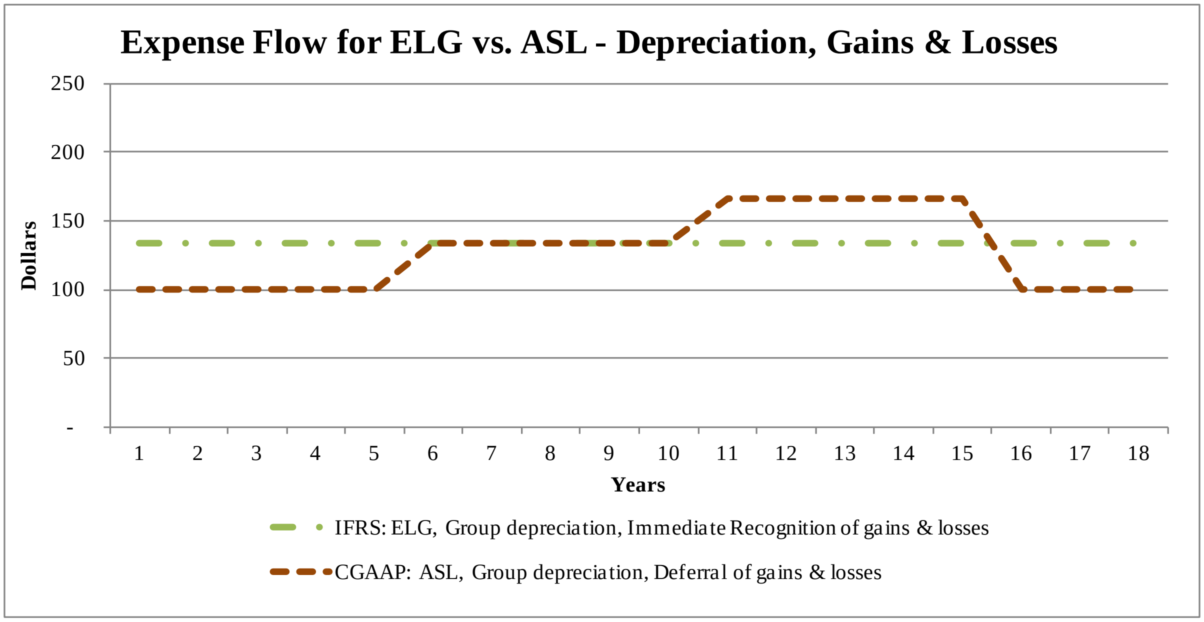
Manitoba Hydro can, however, provide an illustrative example, which demonstrates that the IFRS compliant ELG method is superior for rate making purposes, when compared with Manitoba Hydro's existing CGAAP ASL approach, where gains and losses on asset retirement are deferred and amortized over the remaining life of the assets within the pool.

ILLUSTRATIVE EXAMPLE:

Asset Cost and Retirement Assumptions

A constant level of asset investment is assumed. For simplicity, negative salvage and the effects of inflation are ignored. The asset pool consists of:

- Five units each costing $100, which have an expected service life of five years, and which will be replaced immediately on retirement.
- Five units each costing $100, which have an expected service life of fifteen years, and which will be replaced immediately on retirement.
- All asset retirements and additions occur at the end of the year expected.
- At any point in time:
    - The assets have a combined cost of $1,000;
    - One half of the asset base is expected to last five years and one half of the asset base is expected to last fifteen years; and,
    - The weighted average expected service life of the combined asset group is ten years.



When losses on disposition are deferred and amortized, depreciation expense under the CGAAP ASL method increases over time, even when the asset base does not change. By contrast, the ELG method delivers an equal amount of expense in each year, consistent with the unchanging level of investment in assets. The CGAAP ASL approach does not satisfy the rate making principle of intergenerational equity, as rate payers are undercharged early in the asset pool's life cycle, and are overcharged in the later years of the asset pool's cycle.

In addition, the CGAAP ASL method is not sufficiently componentized to be IFRS compliant. Please see the response to PUB/MH-II-21a-c for a discussion regarding the impacts associated with using the CGAAP ASL method for rate setting purposes.

Section:	Tab 5; Appendix 5.6 pg.11 of 14	Page No.:	PUB/MH I-43 c
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	Changes in Depreciation Rates		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a comparison of Wuskwatim depreciation expense for 2015/16 (by WPLP depreciable group) based on 2014 ASL (without net salvage) and ELG.

b) Please extrapolate the difference in depreciation expense over the entire IFF14.

c) Please indicate to what extent the new account groupings under ELG would have to be expanded for an IFRS compliant ASL-based methodology.

RATIONALE FOR QUESTION:

To assess the impact on revenue requirement related to Wuskwatim G.S of implementing ELG versus ASL.

RESPONSE:

a) Please see the table below for a comparison of Wuskwatim depreciation expense for 2015/16 based on CGAAP ASL (without net salvage) and ELG.

Wuskwatim Power Limited Partnership (WPLP)
Depreciation Expense

Property, Plant & Equipment	ELG No Salvage 2015/16	CGAAP ASL* No Salvage 2015/16	Difference
Hydraulic Generation			
Dams, Dykes and Weirs	1 302 728	1 246 022	56 706
Powerhouse	4 995 399	4 777 574	217 825
Spillway	1 334 124	1 137 412	196 712
Water Control Systems	1 610 947	1 515 825	95 122
Roads and Site Improvements	1 871 146	1 611 033	260 113
Turbines and Generators	2 704 034	2 529 593	174 441
Governors and Excitation System	109 541	102 824	6 717
A/C Electrical Power Systems	953 256	898 356	54 900
Instrumentation, Control and D/C Systems	1 696 646	1 483 700	212 946
Auxiliary Station Processes	1 844 110	1 329 275	514 835
Support Buildings	1 475 256	1 439 850	35 406
Operational Employment Fund	350 688	350 688	-
Total Generation	20 247 875	18 422 152	1 825 723
Substations			
Buildings	5 351	5 025	326
Roads, Steel Structures and Civil Site Work	37 529	35 062	2 467
Power Transformers	139 392	88 745	50 647
Interrupting Equipment	21 336	16 632	4 704
Other Station Equipment	41 505	35 668	5 837
Electronic Equipment and Batteries	55 711	41 544	14 167
Total Substations	300 824	222 676	78 148
Communication			
Fibre Optic and Metallic Cable	5 355	4 245	1 110
Carrier Equipment	2 940	2 355	585
Total Communication	8 295	6 600	1 695
Motor Vehicles			
Heavy Trucks	1 274	1 126	148
Construction Equipment	1 865	1 517	348
Trailers	2 565	2 014	551
Miscellaneous Vehicles	5 124	3 471	1 653
Total Motor Vehicles	10 828	8 128	2 700
General Equipment			
Computer Equipment	3 324	3 324	-
Total General Equipment	3 324	3 324	-
Total WPLP Property, Plant & Equipment	20 571 146	18 662 880	1 908 266
WPLP Intangible Assets	6 412 799	5 473 605	939 194
Total Wuskwatim Power Limited Partnership	26 983 945	24 136 485	2 847 460

* Not IFRS compliant

b) Please see the following table for the difference in depreciation expense over IFF14.

Wuskwatim Power Limited Partnership (WPLP)
Depreciation Expense Difference ASL (no salvage) and ELG

	2017	2018	2019	2020	2021	2022	2023	2024	2025
Difference	2 858 336	2 912 714	2 912 714	2 912 714	2 912 714	2 912 714	2 914 686	2 920 643	2 920 643

	2026	2027	2028	2029	2030	2031	2032	2033	2034
Difference	2 920 643	2 920 643	2 920 643	2 920 643	2 920 643	2 920 643	2 920 643	2 923 049	2 930 313

Please see the responses to PUB/MH-II-21b and PUB/MH II-21c for a discussion regarding the impacts associated with using the CGAAP ASL method of depreciation for rate setting purposes.

c) As indicated on pages 12-14 of Appendix 11.49 Response to the Public Utilities Board Order 43/13, Manitoba Hydro has yet to perform the detailed analysis required to identify the additional components required to apply an IFRS compliant ASL procedure. Examples where additional component groups could be developed for the different asset types (e.g. Hydraulic Generation, Substations, etc) are provided on pages 12-13 of Appendix 11.49.

Section:	Tab 5; Appendix 5.6 Schedule 1	**Page No.:**	PUB/MH I-45a
Topic:	Financial Result & Forecasts		
Subtopic:	Depreciation Expense		
Issue:	Sustaining Capital Spending		

PREAMBLE TO IR (IF ANY):

The asset retirement information filed in the depreciation study is illustrative only and does not reflect Manitoba Hydro's experience. Asset retirement information was filed as Manitoba Hydro Exhibit #54 from the 2012 GRA.

QUESTION:

Please file an update to MH Exhibit #54 reflecting Manitoba Hydro's asset retirements and indicate to which extent each of the asset retired was over- or under-depreciated.

RATIONALE FOR QUESTION:

To understand the implications of asset retirements in assessing the depreciation study.

RESPONSE:

The following table provides the accumulated depreciation balance and loss experienced on disposition of the Dams, Dykes and Weirs assets retired at age intervals 54.5 through 66.5.

As these retirements occurred prior to reaching the average service life of the account, the assets were not fully depreciated at the time of retirement, resulting in losses on disposition equal to approximately 30% of the retirement value of the assets. Under ELG, such losses are expected to be significantly smaller as assets are depreciated over their individual service lives.

Age At Beginning of Interval	Retirements During Age Interval	Hydraulic Generating Facility	Year Retired	Year Installed	Book Accumulated Depreciation at Time of Retirement	Loss on Disposition	Note
54.5	$ 192,434	Seven Sisters	1987	1932	$ 125,811	$ 66,623	(1)
60.5	175,771	Great Falls	1990	1929	117,656	58,115	(2)
61.5	44,894	Great Falls	1989	1927	32,733	12,161	(3)
62.5	19,841	Great Falls	1990	1927	13,735	6,106	(2)
65.5	155,106	Great Falls	1989	1923	114,960	40,146	(3)
66.5	283,771	Great Falls	1990	1923	209,429	74,342	(2)
	$ 871,817				$ 614,324	$ 257,493	

Nature of work triggering asset retirement:

(1) Rehabilitation of concrete for overflow and non-overflow dams

(2) Rehabilitation of concrete and structural steel for overflow and non-overflow dams

(3) Bridge removal

Section:	Appendix 11.15 Appendix 11.37	Page No.:	MFR 9
Topic:	Financial Information		
Subtopic:	Revenue Requirements		
Issue:	Sustaining Capital		

PREAMBLE TO IR (IF ANY):

MH's sustaining capital is wholly funded from internally generated funds, which include Domestic Load Growth revenues and Net Export revenues.

QUESTION:

a) Quantify the Domestic Load Growth revenue impacts on internally generated funding over the IFF period.

b) Indicate the annual dollar and percentage of Sustaining Capital funding derived over the next ten years from:
   - Domestic Load Growth
   - Recent rate increases
   - Non-Wuskwatim/non-Keeyask export revenues

c) Compare the percentages in (b) to the historical post-2008 revenue sources set out in Appendix 11.37.

RATIONALE FOR QUESTION:

To determine MH’s ongoing ability to fund sustaining capital from internally generated funds.

RESPONSE:

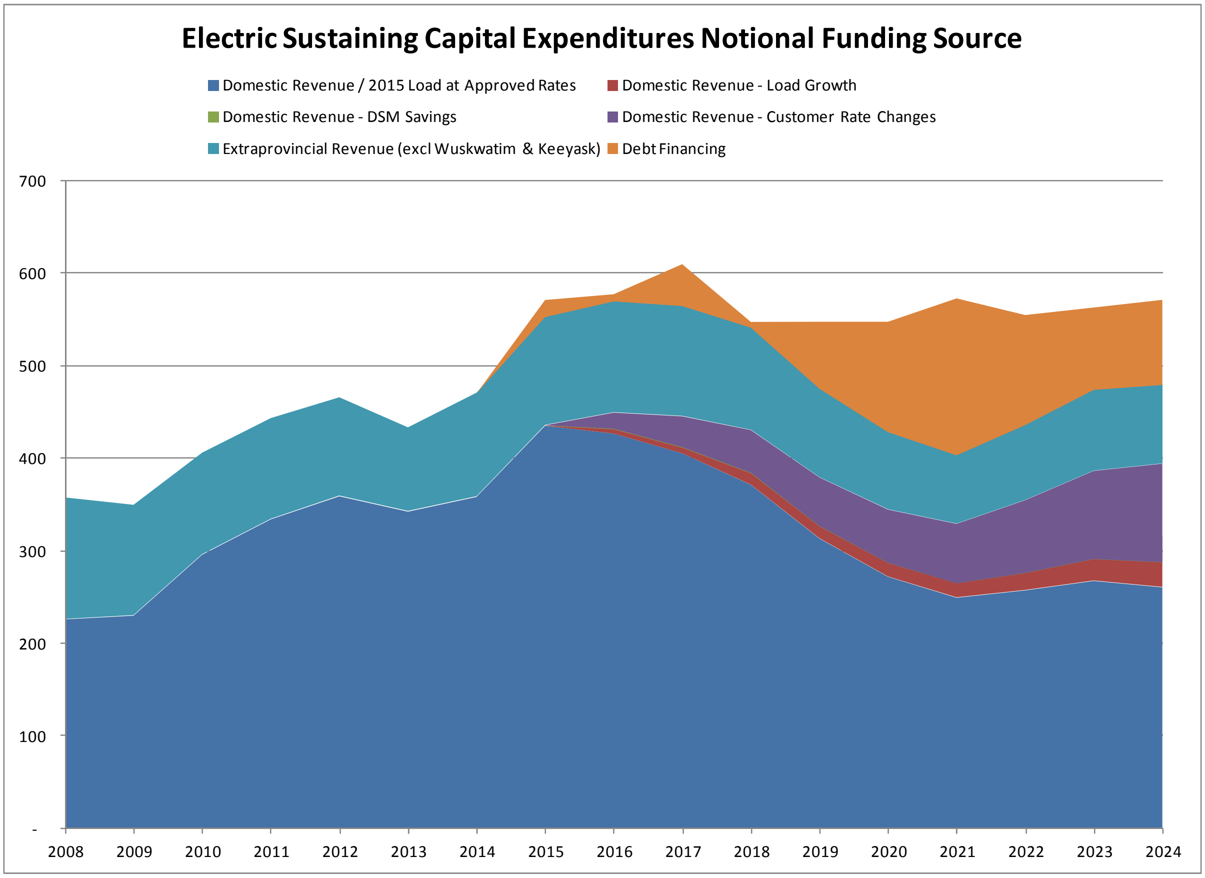
In practice, Manitoba Hydro pools cash at a consolidated level and does not identify specific sources of operational cash for specific uses of cash (for example capital projects or operations).

However, for the purpose of responding to this question, it is assumed that cash flow from operations may be notionally allocated in proportion to the components comprising the cash received from customers (including domestic and export), to Manitoba Hydro's electric operations sustaining capital expenditures. Projected cash flows from domestic customers have been approximately broken down by cash flows from 2015 load at approved rates, load growth, DSM savings and customer rate changes. Historical domestic revenues have not been broken down.

Cash flows from extraprovincial customers are generally not broken down by specific asset due to the integrated nature of the hydro-electric system. However, for the purposes of this response, the extraprovincial revenues associated with Wuskwatim and Keeyask have been excluded based on the estimated revenue requirement provided in the response to PUB/MH-II-5a.

The proportionate allocation based on cash flows received by customers does not directly translate to internally generated funds from domestic customers or internally generated funds from extraprovincial customers due to cash flow cost components not being classified and applied to the associated customer categories.

The following figure and schedule depicts the cash flow from operations, based on a breakdown of cash flow from customers (including domestic and export), to Manitoba Hydro's electric operations sustaining capital expenditures. Except for 2008 and 2009, which were favourable water flow years, extraprovincial revenue is tracking at approximately 20% to 25% of total revenue until the in-service of Keeyask and the new 500kV transmission line. Additional projected debt is required in all forecast years to finance the shortfall in internally generated funds resulting mainly from interest payments and capital taxes increasing more rapidly than revenues, as well as the exclusion of extraprovincial revenues associated with Wuskwatim and Keeyask. Exclusion of Wuskwatim and Keeyask extraprovincial revenues reduces the proportion of extraprovincial to total revenues to around 15% and increases the proportion of debt financing to around 20% to 30%.


Electric Sustaining Capital Expenditures Notional Funding Source
Domestic Revenue / 2015 Load at Approved Rates
Domestic Revenue - Load Growth
Domestic Revenue - DSM Savings
Domestic Revenue - Customer Rate Changes
Extraprovincial Revenue (excl Wuskwatim & Keeyask)
Debt Financing
700
600
500
400
300
200
100
-
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024

(In Millions of Dollars)

				ACTUAL								FORECAST					
For the year ended March 31	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
CASH FROM OPERATING ACTIVITIES																	
Cash Receipts from Customers:																	
Domestic Revenue / 2015 Load at Approved Rates	1 075	1 127	1 145	1 200	1 193	1 341	1 405	1 437	1 437	1 437	1 437	1 437	1 437	1 437	1 437	1 437	1 437
Domestic Revenue - Load Growth								-	27	50	93	128	170	202	237	272	310
Domestic Revenue - DSM Savings								-	(12)	(28)	(45)	(69)	(93)	(114)	(133)	(147)	(161)
Domestic Revenue - Customer Rate Changes								-	60	119	180	244	308	375	445	518	594
Extraprovincial Revenue	625	623	427	398	363	353	439	409	434	450	457	479	514	817	943	959	987
Other	(0)	73	6	23	34	(4)	1	13	12	12	12	12	12	13	13	13	13
Cash Receipts from Customers	1 699	1 823	1 578	1 622	1 590	1 689	1 845	1 859	1 958	2 039	2 134	2 231	2 349	2 729	2 941	3 051	3 180
Cash Paid to Suppliers and Employees	(609)	(713)	(645)	(690)	(721)	(723)	(777)	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 069)	(1 099)	(1 124)	(1 155)
Interest Paid	(525)	(492)	(414)	(406)	(385)	(456)	(480)	(511)	(514)	(547)	(593)	(784)	(928)	(1 222)	(1 349)	(1 329)	(1 341)
Interest Received	33	35	6	24	35	44	72	13	15	21	30	35	34	31	28	15	16
	599	653	524	550	518	554	661	558	587	571	598	482	441	469	522	613	699
% OF TOTAL CASH RECEIPTS FROM CUSTOMERS																	
Cash Receipts from Customers:																	
Domestic Revenue / 2015 Load at Approved Rates	63%	62%	73%	74%	75%	79%	76%	77%	73%	70%	67%	64%	61%	53%	49%	47%	45%
Domestic Revenue - Load Growth	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	6%	7%	7%	8%	9%	10%
Domestic Revenue - DSM Savings	0%	0%	0%	0%	0%	0%	0%	0%	-1%	-1%	-2%	-3%	-4%	-4%	-5%	-5%	-5%
Domestic Revenue - Customer Rate Changes	0%	0%	0%	0%	0%	0%	0%	0%	3%	6%	8%	11%	13%	14%	15%	17%	19%
Extraprovincial Revenue	37%	34%	27%	25%	23%	21%	24%	22%	22%	22%	21%	21%	22%	30%	32%	31%	31%
Other	0%	4%	0%	1%	2%	0%	0%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%
Cash Receipts from Customers	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SUSTAINING CAPITAL EXPENDITURES NOTIONAL FUNDING SOURCE:																	
Domestic Revenue / 2015 Load at Approved Rates	226	230	296	334	359	342	358	435	427	406	372	313	272	249	257	267	260
Domestic Revenue - Load Growth	-	-	-	-	-	-	-	-	8	14	24	28	32	35	42	50	56
Domestic Revenue - DSM Savings	-	-	-	-	-	-	-	-	(3)	(8)	(12)	(15)	(17)	(20)	(24)	(27)	(29)
Domestic Revenue - Customer Rate Changes	-	-	-	-	-	-	-	-	18	33	46	53	58	64	79	95	107
Extraprovincial Revenue	131	119	110	109	106	90	112	123	128	126	117	103	96	140	167	177	177
Keeyask Net Extraprovincial Revenue (PUB/MH-II-5a)	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(47)	(64)	(66)	(68)
Wuskwatim Net Extraprovincial Revenue (PUB/MH-II-5a)	-	-	-	-	-	-	-	(6)	(8)	(7)	(6)	(7)	(9)	(19)	(22)	(23)	(23)
Debt Financing	-	-	-	-	-	-	-	18	8	45	6	72	119	169	119	89	92
Total Sustaining Capital Expenditures	357	349	405	443	465	433	470	571	577	610	547	547	548	573	555	563	571
% OF TOTAL SUSTAINING CAPITAL EXPENDITURES																	
Domestic Revenue / 2015 Load at Approved Rates	63%	66%	73%	75%	77%	79%	76%	76%	74%	67%	68%	57%	50%	44%	46%	48%	46%
Domestic Revenue - Load Growth	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	5%	6%	6%	8%	9%	10%
Domestic Revenue - DSM Savings	0%	0%	0%	0%	0%	0%	0%	0%	-1%	-1%	-2%	-3%	-3%	-3%	-4%	-5%	-5%
Domestic Revenue - Customer Rate Changes	0%	0%	0%	0%	0%	0%	0%	0%	3%	5%	8%	10%	11%	11%	14%	17%	19%
Extraprovincial Revenue	37%	34%	27%	25%	23%	21%	24%	22%	22%	21%	21%	19%	18%	25%	30%	31%	31%
Keeyask Net Extraprovincial Revenue (PUB/MH-II-5a)	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%	-8%	-11%	-12%	-12%
Wuskwatim Net Extraprovincial Revenue (PUB/MH-II-5a)	0%	0%	0%	0%	0%	0%	0%	-1%	-1%	-1%	-1%	-1%	-2%	-3%	-4%	-4%	-4%
Debt Financing	0%	0%	0%	0%	0%	0%	0%	3%	1%	7%	1%	13%	22%	30%	21%	16%	16%
	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Section:	Appendix 11.15 Appendix 11.19	**Page No.:**	MFR 1 MFR 9
Topic:	Financial Information		
Subtopic:	Revenue Requirements		
Issue:	Net Export Revenue Forecasts		

PREAMBLE TO IR (IF ANY):

In Appendix 11.19, MH's net export revenue forecast assumes that MH's MISO sales will achieve unit prices of $65/MWh by 2019/20 compared to $31-34/MWh as experienced from 2009/10 to 2013/14.

QUESTION:

Please indicate Manitoba Hydro's CO2 pricing assumptions, including year of implementation and unit cost in $/MWh.

RATIONALE FOR QUESTION:

To test the impact of a deferral of carbon pricing in the MISO market.

RESPONSE:

Manitoba Hydro uses a consensus forecasting approach for its electricity export price forecast. Inputs to the models used by the price forecast consultants may include CO2 pricing in $/ton or $/tonne. CO2 unit costs in $/MWh are not an input into the price forecast models.

The specific details of Manitoba Hydro's electricity export price forecast, including details on specific pricing factors such as CO2 pricing assumptions, are commercially sensitive information, and therefore are confidential since public release could harm the Corporation in negotiation of contracts for export sales. However, Manitoba Hydro can confirm that the reference case consensus export pricing assumptions used for IFF 14 do not contain any value for CO2 through 2019/20.

The Preamble to the question indicates that average unit export revenues are projected to increase from $31-34/MWh in the 2013/14 timeframe to $65/MWh by 2019/20. As noted in Manitoba Hydro's response to PUB/MH-I-15c, the increase in the average unit revenue is due to a number of factors, including current high water conditions, new export contracts taking effect during the period, inflation and real increase in the market price of electricity.

Section:	Appendix 11.15 Appendix 11.19	**Page No.:**	MFR 1 MFR 9
Topic:	Financial Information		
Subtopic:	Revenue Requirements		
Issue:	Net Export Revenue Forecasts		

PREAMBLE TO IR (IF ANY):

In Appendix 11.19, MH's net export revenue forecast assumes that MH's MISO sales will achieve unit prices of $65/MWh by 2019/20 compared to $31-34/MWh as experienced from 2009/10 to 2013/14.

QUESTION:

Provide an IFF14 that assumes no carbon price until 2019/20.

RATIONALE FOR QUESTION:

To test the impact of a deferral of carbon pricing in the MISO market.

RESPONSE:

A separate MH14 scenario assuming no carbon price until 2019/20 is not available. However, the Low Export Price Scenario included in IFF14 (Appendix 3.3, pages 22-24) assumes no carbon prices over the full 20-year forecast period.

Please note that the Low Export Price Scenario provides the financial impacts of a plausible lower bound for the forecast of long term export prices and includes factors such as low economic growth, aggressive energy conservation policies, low growth in energy demand, lower natural gas and coal prices and a US move to self-sufficiency in energy supply, in addition to no carbon prices.

The projected financial statements for the Low Export Price Scenario are provided in Appendix 3.5 (pages 20-25).

Section:	Appendix 11.15	Page No.:	
Topic:	Financial Information		
Subtopic:	In-service Costs of Major G&T projects		
Issue:	Net revenue requirement for each major G&T project		

PREAMBLE TO IR (IF ANY):

In Appendix 11.5, Manitoba Hydro is providing revenue requirements for a number of capital projects.

QUESTION:

a) Refile Appendix 11.15 to include the Wuskwatim and Keeyask project revenue stream by adding a project revenue line (as per WPLP (appendix 11.5) and KHLP (Appendix 11.6) agreements). Using this data, indicate the annual net in-service revenue requirement and the annual percentage rate increase to offset this net revenue requirement.

b) Create a new table in the refiled Appendix 11.15 that, for each of the IFF years, sets out, in consecutive rows:
i. Manitoba Hydro’s annual net export revenue;
ii. The net in-service revenue requirement for Keeyask;
iii. The net in-service revenue requirement for Wuskwatim;
iv. The revenue requirement for Bipole III;
v. The revenue requirement for the Great Northern Transmission Line;
vi. The total of columns (ii)-(v); and
vii. The difference between rows (i) and (vi).

c) Provide a graphical illustration, by year, of Appendix 11.5 that progressively stacks the in-service revenue requirements of each major G&T project and compares the separately depicted net extra-provincial and proposed rate increase revenue streams.

d) Illustrate how Appendix 11.15 in-service costs for Sustaining Capital projects, and DSM were calculated.

RATIONALE FOR QUESTION:

To test the extent to which key G&T projects can be funded by exports in the IFF years.

RESPONSE:

a) Please see the response to PUB/MH-II-5 Attachment A for an update to Appendix 11.15, including the attributed extraprovincial revenues and fuel and power purchased to the Keeyask, Wuskwatim and Bipole III projects.

As noted in the response to PUB/MH-II-5, projected extraprovincial revenues, net of fuel and power purchased have been allocated to Keeyask, Wuskwatim and Bipole III based on the percentage of average energy output of the project (or the loss reduction in the case of Bipole III) relative to total system supply. The WPLP and KHLP revenues are not assumed in this response as they reflect the negotiated power purchase arrangements between Manitoba Hydro and the First Nations.

b) Manitoba Hydro does not accept the supposition that extraprovincial revenues fund major new generation and transmission projects in priority over other cash outflows. Manitoba Hydro pools its cash at the consolidated level and does not specify sources of cash for uses of cash. Cash outflows are funded through the combination of internally generated funds (comprised partly of extraprovincial revenues) and debt.

However, for the purposes of responding to this question, the data points for the figure in part c) below are included in the following table.

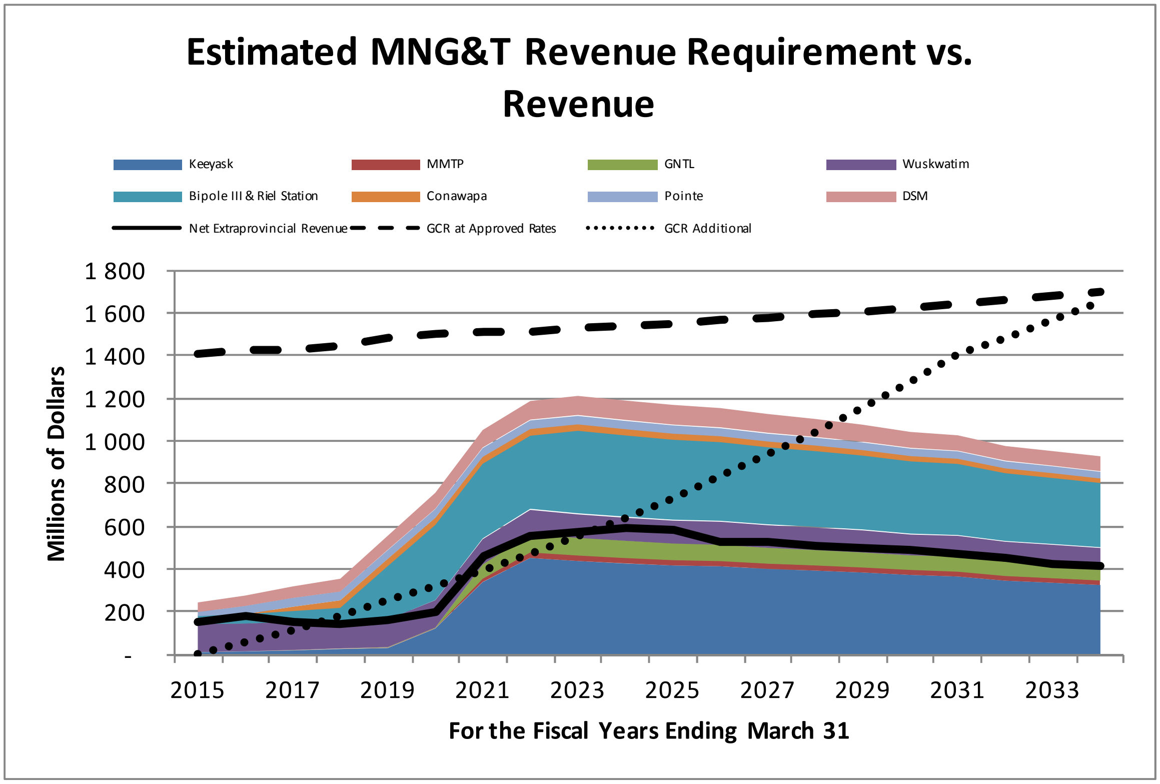
($Millions)

	For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
i.	Net Extraprovincial Revenue	150	181	147	142	160	195	459	554	569	588
ii.	Keeyask	8	12	17	23	28	119	337	449	435	424
iii.	Wuskwatim	133	131	134	134	132	130	120	115	111	109
iv.	Bipole III & Riel Station	40	47	53	60	251	353	351	344	388	382
v.	MMTP	0	0	1	1	2	2	17	28	27	27
v.	GNTL	0	0	0	1	2	3	68	87	84	82
	Conawapa	-	-	20	36	35	34	34	33	32	31
	Pointe	20	39	42	42	41	41	41	40	40	39
	DSM	44	49	53	60	66	75	81	86	89	90
vi.	Estimated MNG&T Revenue Requirement	245	278	320	356	556	756	1 048	1 183	1 207	1 185
vii.	Net Extraprovincial Revenue less Estimated MNG&T Revenue Requirement	(95)	(97)	(173)	(214)	(397)	(561)	(589)	(629)	(637)	(597)

($Millions)

	For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
i.	Net Extraprovincial Revenue	586	521	528	505	496	491	469	449	427	414
ii.	Keeyask	414	410	398	390	381	370	362	343	333	323
iii.	Wuskwatim	108	108	106	106	104	99	98	94	92	91
iv.	Bipole III & Riel Station	376	370	363	356	348	340	335	319	311	303
v.	MMTP	27	26	26	26	25	25	24	23	23	22
v.	GNTL	80	78	76	74	72	69	72	69	66	64
	Conawapa	30	30	29	28	27	26	26	24	23	23
	Pointe	39	38	37	37	36	35	35	33	33	32
	DSM	91	90	87	83	79	74	71	68	68	69
vi.	Estimated MNG&T Revenue Requirement	1 165	1 150	1 122	1 099	1 073	1 039	1 023	974	950	926
vii.	Net Extraprovincial Revenue less Estimated MNG&T Revenue Requirement	(579)	(629)	(595)	(595)	(577)	(548)	(554)	(525)	(523)	(511)

c) The following figure provides the Major New Generation & Transmission estimated revenue requirement from PUB/MH-II-5a compared to net extraprovincial revenue, general consumers revenue at approved rates and general consumers revenue.



d) The estimated revenue requirement for DSM and sustaining capital expenditures in PUB/MH-II-5a are calculated on the same basis as the Major New Generation and Transmission:

- Finance expense is calculated by applying the average interest rate to the average regulatory asset balance or net capital requirement.
- OM&A for DSM is based on the projected operating costs from the PowerSmart Plan. Manitoba Hydro does not track projected OM&A separately between existing assets and projected sustaining capital expenditures. As such, an estimate for sustaining capital expenditure projected OM&A is not provided.
- Amortization of DSM is calculated based on a 10-year amortization and depreciation for sustaining capital expenditures is the aggregate depreciation expense for Major and Base Capital from CEF14.
- Capital taxes are estimated based on 0.5% of the average regulatory asset balance or net capital requirement.

Section:	Tab 5: Schedule 5.1.6 Appendix 5.6 pg.7	**Page No.:**	PUB/MH I-46 (a) & (b)
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	Depreciation Rate Changes		

PREAMBLE TO IR (IF ANY):

Please refile PUB/MH I-46(b) excluding net salvage from the ASL based rates.

QUESTION:

To test the impact of an ASL-based approach to depreciation.

RATIONALE FOR QUESTION:

RESPONSE:

The following schedule provides a comparison, for the 2015/16 and 2016/17 fiscal years, of the applied for ELG depreciation with the depreciation expense which would result from the continuation of CGAAP ASL based depreciation rates and the removal of any provision for net salvage. Please note that the CGAAP ASL without salvage depreciation figures presented in this schedule are not IFRS compliant.

Please see the response to PUB/MH-II-21b and PUB/MH-II-21c for a discussion regarding the impacts associated with using the CGAAP ASL method of depreciation for rate setting purposes.

MANITOBA HYDRO
DEPRECIATION AND AMORTIZATION EXPENSE
COMPARISON OF ELG AND ASL WITHOUT SALVAGE **(000's)**

	Schedule 5.1.6		CGAAP ASL without Net Salvage *		Difference	
	2015/16 Forecast ELG	2016/17 Forecast ELG	2015/16 Forecast ASL	2016/17 Forecast ASL	2015/16 Forecast	2016/17 Forecast
Generation						
Hydraulic Generating Stations	92,265	96,041	84,781	87,713	7,484	8,328
Thermal Generating Stations	15,755	15,856	14,138	14,195	1,617	1,661
Demand Side Management	34,957	37,501	34,957	37,501	0	0
Diesel Generating Stations	2,557	2,111	2,320	1,874	237	237
Wuskwatim	26,984	27,082	24,136	24,351	2,848	2,731
Amortization of Contributions	(1,146)	(1,146)	(1,146)	(1,146)	(0)	(0)
	$ 171,373	$ 177,446	$ 159,186	$ 164,488	$ 12,187	$ 12,958
Transmission						
Transmission	13,369	14,367	12,684	13,596	685	771
Amortization of Contributions	(3,054)	(3,059)	(3,297)	(3,302)	243	243
	$ 10,315	$ 11,308	$ 9,387	$ 10,294	$ 928	$ 1,014
Stations						
Substations	85,735	90,177	77,584	81,468	8,151	8,709
Transformers	1,597	1,828	1,514	1,768	83	60
Amortization of Contributions	(4,402)	(4,402)	(4,433)	(4,547)	31	145
	$ 82,930	$ 87,603	$ 74,665	$ 78,689	$ 8,265	$ 8,914
Distribution						
Subtransmission Lines	6,948	7,401	5,390	5,763	1,558	1,638
Distribution Lines	56,989	60,951	47,601	50,919	9,388	10,032
Meters & Transformers	3,281	3,404	2,952	3,062	329	342
Amortization of Contributions	(6,409)	(7,009)	(6,408)	(7,008)	(1)	(1)
	$ 60,809	$ 64,747	$ 49,535	$ 52,736	$ 11,274	$ 12,011
Other						
Communications	17,765	18,206	16,141	16,505	1,624	1,701
Motor Vehicles	11,819	12,226	10,730	11,089	1,089	1,137
Structures & Improvements	8,800	9,557	8,112	8,809	688	748
General Equipment	16,780	16,797	16,780	16,796	0	1
Computer Development	18,487	20,816	18,248	20,540	239	276
Conawapa	-	7,711	-	7,711	-	0
Affordable Energy Fund	4,290	1,509	4,290	1,509	0	(0)
Miscellaneous	2,652	3,269	2,385	3,003	266	266
Corporate Allocation	(1,850)	(1,853)	(1,583)	(1,586)	(267)	(267)
Target Adjustment	(3,305)	(6,938)	(3,030)	(6,324)	(275)	(614)
	$ 75,439	$ 81,300	$ 72,074	$ 78,053	$ 3,365	$ 3,248
Total D & A Expense	$ 400,866	$ 422,404	$ 364,847	$ 384,260	$ 36,019	$ 38,145

* The ASL no Salvage figures presented for 2015/16 & 2016/17 are not IFRS compliant

Section:	Tab 7, Appendix 7.1	Page No.:	PUB/MH I-54(b)
Topic:	Electric Load Forecast		
Subtopic:	Industry Sector Load Growth		
Issue:	Forecast growth surge		

PREAMBLE TO IR (IF ANY):

MH's Top Consumers are expected to increase energy consumption from 5,461 GWh in 2013/14 to 7,177 GWh in 23/24, following a decline in the previous six years.

QUESTION:

a) Provide a companion table to PUB/MHI-54(b) showing the peak annual industry sector demand in MW.

b) Indicate the current contracted demand for each industry sector.

RATIONALE FOR QUESTION:

To test Manitoba Hydro's assumptions regarding industrial load growth.

RESPONSE:

The following table presents the peak annual hourly megawatt usage (MW) by the Top Consumers within each sector (i.e. the non-coincident peak) in each of the historical fiscal years from 2007/08 to 2013/14.

Non-Coincident Peak Demand for Top Consumers by Industry Sector (MW)

Fiscal Year	Primary Metals & Mining	Chemical / Treatment	Petro / Oil / Natural Gas	Pulp / Paper	Food / Beverage	College
2007/08	351	255	179	120	36.9	17.6
2008/09	341	253	184	117	37.6	14.5
2009/10	368	253	188	114	37.0	14.9
2010/11	370	253	226	35	37.8	15.3
2011/12	371	254	202	39	36.9	16.9
2012/13	371	265	188	43	39.1	16.8
2013/14	367	263	165	40	38.2	17.0
Average Annual Growth	0.7%	0.5%	-1.3%	-16.7%	0.6%	-0.6%

The following table provides the present aggregated contract demand for each industry sector.

Aggregated Contract Demand for Top Consumers by Industry Sector (MW)

Primary Metals & Mining	Chemical / Treatment	Petro / Oil / Natural Gas	Pulp / Paper	Food / Beverage	College
429	234	310	50	48	22

Please note that Manitoba Hydro does not forecast demand for individual customers or sector peaks.

Section:	9 Figure 9.3, P.7	**Page No.:**	PUB/MH I-55
Topic:	Energy Supply		
Subtopic:	DSM Impacts		
Issue:	Changes to DSM Load Reductions		

PREAMBLE TO IR (IF ANY):

In PUB/MH I-55, Manitoba Hydro provides a comparison between DSM savings included in the Level 2 DSM option discussed during the NFAT and projections in the 2014 Power Resource Plan.

QUESTION:

Please file the 2014 Power Resource Plan.

RATIONALE FOR QUESTION:

To explore the reasons for the difference between DSM impacts presented at the NFAT with that included in the current rate application

RESPONSE:

Please see the attachment to PUB/MH-I-58 for the 2014 Power Resource Plan.

Section:	9 Figure 9.3, P.7	Page No.:	PUB/MH I-55
Topic:	Energy Supply		
Subtopic:	DSM Impacts		
Issue:	Changes to DSM Load Reductions		

PREAMBLE TO IR (IF ANY):

In PUB/MH I-55, Manitoba Hydro provides a comparison between DSM savings included in the Level 2 DSM option discussed during the NFAT and projections in the 2014 Power Resource Plan.

QUESTION:

b) Please explain the factors behind delaying the launch of the of fuel choice programs to 2017/18?

c) Please explain the factors behind delaying the introduction of conservation rates to 2017/18

RATIONALE FOR QUESTION:

RESPONSE:

As outlined in Manitoba Hydro's response to PUB/MH-I-55, the NFAT Update Level 2 DSM savings were created as part of a sensitivity run for the NFAT hearing. At that point, none of the DSM options were formally approved as the Corporation's DSM plan.

Subsequently, the Corporation developed its 2014 Power Smart Plan in consultation with the Minister responsible for Manitoba Hydro in accordance with the Energy Savings Act. The timing and level of DSM energy savings included in the Plan were based upon more detailed and refined program designs and upon the outcome of consultations with the provincial government.

Discussions on the merits and issues associated with contemplated Conservation Rate initiatives were not held with the Provincial Government at that time as Manitoba Hydro needed to undertake further study and analysis. To allow for this work to be undertaken, the timing of the Conservation Rate initiatives was deferred to 2017/18.

Discussions with the Provincial Government on the merits and issues associated with pursuing a Fuel Choice Program concluded with Manitoba Hydro taking an educational campaign approach in pursuing the opportunities associated with fuel choice.

Section:	Tab 3, Appendix 3.3 Appendix 11.48	Page No.:	PUB/MH I-64(a)
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Export Contracts		
Issue:	Sales from 2015 to 2030		

PREAMBLE TO IR (IF ANY):

In PUB/MH I-64(a), MH indicated the potential total revenue related to signed contracts, but did not provide capacity and energy commitments by contract.

QUESTION:

a) On Figures 1 and 2 of Appendix 11.48, please provide a row for each export contract listed in Tables 1, 2, and 3 of PUB/MH I-46(a) that shows the capacity and energy commitments under that contract by year.

b) For each of the contracts in Tables 1, 2, and 3, please indicate which contracts have fixed prices for energy and/or capacity, and which ones are subject to market pricing.

RATIONALE FOR QUESTION:

To understand Manitoba Hydro's capacity and energy commitments.

RESPONSE:

The information requested is subject to confidentiality provisions requiring the consent of the counterparties and as such, Manitoba Hydro is not in a position to file the information requested. Manitoba Hydro can however, confirm that nothing has changed in the agreements since the review conducted during the 2014 Needs For and Alternative To hearing.

Section:	Appendix 9.1 Appendix 11.22	**Page No.:**	PUB/MH I-66(a) PUB/MH I-83(b)
Topic:	Power Resources		
Subtopic:	Hydraulic Generation		
Issue:	Actual 2013/14 power resources		

PREAMBLE TO IR (IF ANY):

MH's peak winter domestic load in 2013/14 was 4,743 MW when compared to 5,133 MW of hydraulic generation capacity was not quite sufficient to satisfy the Permit No. 224 export requirement of 500 MW (plus 50 MW transmission losses).

QUESTION:

a) Explain how MH dealt with the 160 MW shortfall in peak capacity.

b) Did MH utilize the existing diversity agreements to satisfy the on-peak need? If not, explain.

c) Provide the monthly cost data on the on-peak purchases ($M/GWh/¢/kWh).

d) Did MH employ the CRP resource?

RATIONALE FOR QUESTION:

MH's winter supply demand criteria appear to involve significant peak capacity imports in high demand years as well as low flow years.

RESPONSE:

a) Manitoba Hydro did not have a shortfall in capacity during the 2013/14 peak load hour, nor was it a net importer in that hour.

Table 9.1 of Tab 9 of the Application lists available thermal and import capacity resources in addition to its existing hydraulic generation. The 2013/14 winter capacity resources were similar to what was provided in Table 9.1 for 2014/15 (6,123 MW total base supply power resources); totaled together, these resources exceeded the actual 2013/14 peak domestic load plus Manitoba Hydro's coincident capacity obligations in its long term export contracts.

In anticipation of the peak load hour of 2013/14, Manitoba Hydro chose to purchase energy from MISO in the Day Ahead market rather than schedule the operation of more expensive thermal generation in Manitoba. A portion of these purchases was used to meet firm export obligations with the balance required to meet projected Manitoba load requirements. Manitoba Hydro planned to utilize the firm transmission associated with its seasonal diversity agreements to ensure delivery of the MISO market energy into Manitoba.

In the operating day, as the hour approached, it was apparent Manitoba Hydro had a net surplus so Manitoba Hydro ended up selling back 100 MW into the MISO Real Time market in the peak hour, at a profit over its Day Ahead purchase.

Accounting for all exports, imports and financial settlements, Manitoba Hydro's net transaction was 90 MW export in the peak hour. This net export position was possible through the use of Manitoba Hydro's portfolio of resources including hydraulic generation, thermal generation, wind PPAs, Day Ahead purchases and exports, Real Time exports and firm transmission assets.

b) No, Seasonal Diversity energy was not purchased over the peak hour. However, Manitoba Hydro used the firm north-bound transmission reservation associated with its diversity agreements to schedule imports from the MISO Day Ahead market.

c) For January 2014, Manitoba Hydro purchased 71 GWh at a cost of $5 million during on peak hours. The average cost was 7.9 cents/kWh.

d) No, use of curtailable load was not required during this peak load hour.

Section:	Tab 4, App 4.1	**Page No.:**	PUB/MH I-66a
Topic:	Power Resource Plan		
Subtopic:	HVDC System Capabilities		
Issue:	Bipole I, II & III utilization		

PREAMBLE TO IR (IF ANY):

PUB/MH I-66(a) does not fully address the percent on-line time of MH's Lower Nelson River hydraulic generation.

QUESTION:

Please calculate MH's maximum annual hydraulic generation output from the Lower Nelson River generating stations and indicate the percentage of total nameplate capacity that this constitutes.

RATIONALE FOR QUESTION:

This question seeks information that was expected to be filed as part of PUB/MH I-66(a).

RESPONSE:

It is unclear if this question is seeking information on power (MW) or energy (GWh) output as a percentage of nameplate capacity.

There have been instances where the total hourly output from the Lower Nelson River stations has been over 100% of nameplate capacity. For example, on December 2, 2000 hourly total Lower Nelson River output was recorded to be 3,596 MW or 101.2% of station capacity values provided in PUB/MH-I-66a.

Maximum actual fiscal year total output from the Lower Nelson River stations occurred in 2005/06 when the gross output was 27,323 GWh. Using the Lower Nelson River station capacity values provided in PUB/MH-I-66a, this translates to a capacity factor of 87%.

Section:	Tab 4, App 4.1	**Page No.:**	PUB/MH I-66(a)
Topic:	Power Resource Plan		
Subtopic:	HVDC System Capabilities		
Issue:	Bipole I, II & III utilization		

PREAMBLE TO IR (IF ANY):

PUB/MH I-66(a) does not fully address the percent on-line time of MH's Lower Nelson River hydraulic generation.

QUESTION:

Please indicate expected annual HVDC losses (GWh) under maximum hydraulic generation conditions for the three Lower Nelson plants.

RATIONALE FOR QUESTION:

This question seeks information that was expected to be filed as part of PUB/MH I-66(a).

RESPONSE:

The expected annual HVDC losses are not available for the three plants as the losses are dependent on the total load transmitted by the HVDC system and are independent of where the generation occurs.

The year with the maximum hydraulic generating conditions for the lower Nelson plants was 2005/06 in which 27,323 GW.h (average load of 3119 MW) was generated. The estimated HVDC losses for the 2005/06 year totaled 2215 GW.h (average estimated loss of 253 MW). The HVDC losses during the maximum experienced hourly loading of 3598.6 MW (in 2000/01) was 315.6 MW.

Section:	Tab 4, App 4.1	Page No.:	PUB/MH I-66(a)
Topic:	Power Resource Plan		
Subtopic:	HVDC System Capabilities		
Issue:	Bipole I, II & III utilization		

PREAMBLE TO IR (IF ANY):

PUB/MH I-66(a) does not fully address the percent on-line time of MH's Lower Nelson River hydraulic generation.

QUESTION:

For 2013/14, Q3 & Q4, indicate the 5x16 Lower Nelson River generating stations' monthly energy output (GWh) that was achieved.

RATIONALE FOR QUESTION:

This question seeks information that was expected to be filed as part of PUB/MH I-66(a).

RESPONSE:

2013/14 Q3 and Q4 monthly total 5x16 Lower Nelson River generation is provided below.

Month	Lower Nelson River 5x16 Generation (GWh)
Oct-13	1141
Nov-13	1045
Dec-13	1115
Jan-14	1156
Feb-14	974
Mar-14	1008

Section:	Tab 4, App 4.1	Page No.:	PUB/MH I-66(a)
Topic:	Power Resource Plan		
Subtopic:	HVDC System Capabilities		
Issue:	Bipole I, II & III utilization		

PREAMBLE TO IR (IF ANY):

PUB/MH I-66(a) does not fully address the percent on-line time of MH's Lower Nelson River hydraulic generation.

QUESTION:

In 2013/14, what was the capacity factor of the Bipole I & II HVDC systems?

RATIONALE FOR QUESTION:

This question seeks information that was expected to be filed as part of PUB/MH I-66(a).

RESPONSE:

The total annual lower Nelson generation during 2013/14 was 24453 GWh or 2791 MW averaged over 8760 hours of the year. The maximum capacity of the Bipoles without reserve is 3854 MW, and as such the capacity factor based on this rating would be 72.4%.

Section:	Tab 4: App. 4.1 App. 11.37	**Page No.:**	PUB/MH I-67 c
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining [Base] Capital Expenditures		
Issue:	Projected Spending Levels		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update the analysis provided including the years covered by CEF08, CEF09, CEF10 and CEF11-2 , as well as actuals for each year, and comment on any changes in trends.

RATIONALE FOR QUESTION:

To explore changes in sustaining capital expenditure over time.

RESPONSE:

Please find the updated graph and table of corresponding data points below.

Comments on forecast trends are as follows:

As demonstrated in the graph, each CEF generally reflects higher spending plans in the early years resulting from detailed project planning and reallocation of cash flow. Following the early years, each CEF generally returns to a gradually increasing level of forecast spending at or below rates of inflation over the long term. Actual spending has been increasing over time to maintain reliable service and address capacity requirements for customers.

The CEF08 and CEF09 forecasts are essentially the same with some variation mainly due to the reallocation of cash flows.

In CEF10 over CEF09, spending increased over the long term to include provisions for future unidentified capital needs as a result of extending the CEF to a 20 year forecast period.

The CEF11-2 sustaining capital forecast remains the same as CEF10-2 through to 2020 followed by an increase to the provisions for future unidentified capital to account for additional capital requirements related to growth, renewal and replacement. Overall, CEF11-2 is lower than CEF10-2 due to the reduction of ineligible overhead capitalized.

The CEF12 sustaining capital forecast is higher in the first few years, as compared to CEF11-2, primarily due to:

- Transmission station requirements to address capacity constraints
- Supporting new customer service requests;
- The addition of the Gillam Townsite infrastructure refurbishment.

The changes between CEF12 and CEF11-2 in the later years are mainly due to a reallocation of cash flow, including the advancement and approval of the Bipole 2 Thyristor Valve Replacement project from the long term provisions for future unidentified capital.

The CEF13 sustaining capital forecast is higher in the first few years, as compared to CEF12, primarily due to:

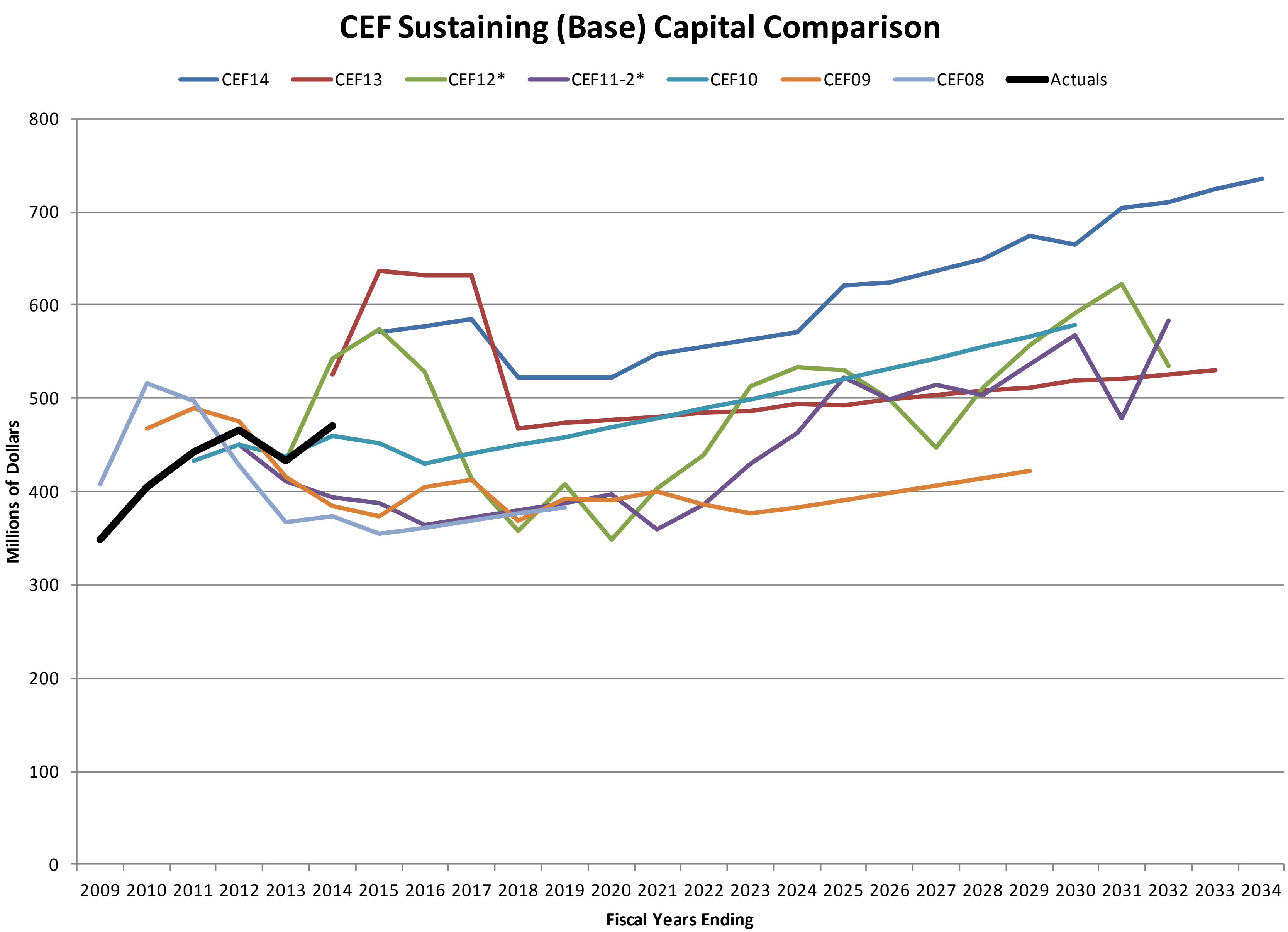
- Distribution substation development both within and outside the city of Winnipeg to address operational load conditions beyond maximum load ratings;
- Transmission line upgrades required to comply with NERC;
- Expenditures required to rehabilitate and replace aging assets based upon condition assessment data;
- Increased work required for the Great Falls Unit 4 Overhaul.

Beginning in 2017/18, base target values were reduced to more recent historic spending levels to 2021/22 and incorporates inflationary growth at 1% thereafter.

In CEF14, sustaining capital was decreased compared to CEF13 in the earlier years and spread out over the next four years to 2021/22 and incorporates inflationary growth at 2% thereafter. The overall increase in CEF14 over CEF13 reflects the findings of the Asset

Condition Assessment report as well as the impacts of capacity constraints and load growth. High priority areas of capital investment include:

- Distribution substation development both within and outside the city of Winnipeg to address operational load conditions beyond maximum load ratings;
- Supporting new customer service requests;
- Higher than average load growth exceeding firm capacity in certain geographic areas of the province;
- System capacity increases associated with Bipole III and new generation.


CEF Sustaining (Base) Capital Comparison
CEF14
CEF13
CEF12*
CEF11-2*
CEF10
CEF09
CEF08
Actuals
800
700
600
500
400
300
200
100
0
Millions of Dollars
2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034
Fiscal Years Ending

Sustaining Capital (in millions of $)

	CEF14	CEF13	CEF12*	CEF11-2*	CEF10	CEF09	CEF08	Actuals
2009							407	349
2010						467	517	405
2011					433	489	497	443
2012				451	451	475	428	465
2013			434	412	439	416	368	433
2014		526	543	394	460	384	374	470
2015	571	637	574	387	452	374	354	
2016	577	631	529	364	430	404	361	
2017	585	632	414	372	440	412	369	
2018	522	468	358	380	450	369	376	
2019	522	474	408	388	458	392	384	
2020	523	477	348	396	469	390		
2021	548	481	403	360	479	400		
2022	555	484	440	386	489	386		
2023	563	487	512	430	499	376		
2024	571	493	533	462	510	384		
2025	621	493	530	523	521	391		
2026	624	499	499	499	532	399		
2027	637	503	447	515	543	407		
2028	649	508	512	503	555	415		
2029	675	512	557	536	567	423		
2030	665	520	591	568	579			
2031	703	521	623	479				
2032	711	526	535	584				
2033	724	531						
2034	735							

**** Includes IFRS OH Adjustment made outside CEF in IFF***

Section:	Appendix 4.1 Appendix 11.7	Page No.:	PUB/MH I-67(b) & (c)
Topic:	Capital Expenditures Forecast		
Subtopic:	Sustaining (Base) Capital Expenditure		
Issue:	Increased Spending Levels		

PREAMBLE TO IR (IF ANY):

MH's billing inserts contained a new capital expenditure for Limestone Generating Station (generators & turbines) already underway. This project did not appear in prior CEF(s).

QUESTION:

Please provide the capital estimate for this project and the rationale for its recent occurrence.

RATIONALE FOR QUESTION:

To explore the reasons for increases in base capital spending.

RESPONSE:

Of the work mentioned in the bill insert, only the governor digital control system replacements for Limestone Units 4 and 5 were completed as a capital project. The cost of this capital project was included in both CEF13 and CEF14 as a base capital item in the amount of $4.6 million. This project includes the replacement of the controls on all 10 units at Limestone (3 in 2014 and 7 more units over the next few years). The remainder of the work discussed in the bill insert was routine maintenance (performed every 12 years) and charged to the station's operating budget.

The original equipment manufacturer is no longer supporting these controls or manufacturing the spare proprietary parts. Manitoba Hydro's inventory of replacement control cards is at a critical level and there has been a high rate of card failure in recent years. This project was undertaken as failure of the control system would cause a unit to be forced offline for several months, or more.

Section:	Tabs 5/9/11	Page No.:	PUB/MH I-69(a)
Topic:	Export Revenue Forecasts		
Subtopic:	Firm and Opportunity Sales into MISO		
Issue:	EPA impact on unit export revenues		

PREAMBLE TO IR (IF ANY):

In IFF14, MH anticipates EPA CO2 pricing impacts as early as 2016/17. PUB/MH I-69(a) suggests an EPA timeline that could be as late as 2019/20.

QUESTION:

Explain how CCCT generation costs will be affected by the EPA regulations. Please quantify the impact in ¢/kWh.

RATIONALE FOR QUESTION:

To explore the impact of the proposed new EPA regulations on export revenues to Manitoba Hydro.

RESPONSE:

Manitoba Hydro clarifies that the statement in the Preamble "In IFF14, MH anticipates EPA CO2 pricing impacts as early as 2016/17" is incorrect. Manitoba Hydro's export price forecast assumptions for IFF14 are based on a consensus view of electricity price forecast consultant work completed subsequent to the price forecast analysis utilized for NFAT. As indicated in Manitoba Hydro's response to PUB/MH-II-31a, the reference case consensus export pricing assumptions used for IFF14 do not contain any value for CO2 through 2019/20.

As noted in the response to PUB/MH-I-69a, each state has a unique emission intensity reduction target to meet by 2030. Following the release of the final rule, expected to be in the summer 2015, states will have one year (and up to two additional years if they choose to work with other states) to submit a plan to the EPA outlining how they will implement the rule and meet these unique emission intensity reduction targets.

The EPA's draft Clean Power Plan assigns each state an emissions rate goal, in pounds of carbon dioxide (CO2) per megawatt hour (MWh), but also gives states an option to translate this goal into a mass-based goal, in pounds of CO2. From an economic perspective, a regional carbon trading program with a mass-based cap is believed to be the most cost effective way to implement the carbon policy goals, but each state must make the decision whether to go in that direction.

The precise manner in which thermal generation costs, including CCCT generation costs are impacted by the proposed EPA regulations will depend upon the individual state implementation plans, which have not yet been developed, and could vary from state to state. Until EPA's final rule is issued and states develop their individual implementation plans, detailed modeling of the impacts of the Clean Power Plan is difficult.

Under the assumptions that a regional carbon trading program is implemented, carbon has a value of $30/ton (a value consistent with preliminary regional transmission organization assessments), and a CCCT generator has a carbon emissions rate of 0.5 tons of CO2 per MWh; then the incremental operating cost of the CCCT generator would be $15/MWh (1.5 cents/kWh). This example is illustrative of the potential cost impact on a CCCT generator. The actual impact on market prices will differ as the marginal generator in a power market can change as often as every five minutes, resulting in a different generation with different fuel/generation technology/emission rates setting the marginal price.

Section:	Tabs 5/9/11	Page No.:	PUB/MH I-69(a)
Topic:	Export Revenue Forecasts		
Subtopic:	Firm and Opportunity Sales into MISO		
Issue:	EPA impact on unit export revenues		

PREAMBLE TO IR (IF ANY):

In IFF14, MH anticipates EPA CO2 pricing impacts as early as 2016/17. PUB/MH I-69(a) suggests an EPA timeline that could be as late as 2019/20.

QUESTION:

Update PUB/MH I-81(b) average unit export price and potential opportunity sales unit prices to reflect recent trends in natural gas pricing and a delay in CO2 regulation.

RATIONALE FOR QUESTION:

To explore the impact of the proposed new EPA regulations on export revenues to Manitoba Hydro.

RESPONSE:

As noted in Manitoba Hydro's response to PUB/MH-II-31a, Manitoba Hydro can confirm that the reference case consensus export pricing assumptions used for IFF 14 do not contain any value for CO2 through 2019/20.

Please see Attachment B of Manitoba Hydro's response to PUB/MH-I-10b for a Projected Operating Statement for Updated Interest Rates and Net Extraprovincial Revenues.

Please see Manitoba Hydro's response to PUB/MH-II-89 for information regarding the requested unit revenue/ cost calculations. These revised financial documents reflect recent trends in natural gas pricing.

Section:	Tab 5: Section 5.14	**Page No.:**	PUB/MH I-70 b
Topic:	Financial Results and Forecast		
Subtopic:	OM&A Expenditures		
Issue:	Cost Containment Initiatives		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a comparison between forecast projections for position reductions in 2014/15 compared to actuals achieved.

RATIONALE FOR QUESTION:

To understand Manitoba Hydro salary cost containment measures.

RESPONSE:

Actual results to March 31, 2015 are not yet available, however the following table compares the 2014/15 forecast position reductions (or equivalent cost reduction) by Business Unit, from PUB/MH-I-70b, to actual reductions achieved to the end of the third quarter, December 31, 2014. As demonstrated, the Corporation is committed to reducing OM&A costs and has already achieved some of the position reductions projected for 2015/16. All Business Units are anticipated to achieve their projected reductions by fiscal year end.

Position (or Equivalent) Cost Reductions for 2014/15

	Actual Reductions achieved to December 2014	*Projected Reductions to March 2015	Higher/ (Lower) than Projected
President & CEO	0	2	(2)
General Counsel & Corporate Secretary	2	1	1
Human Resources & Corporate Services	40	33	7
Corporate Relations	3	3	0
Finance & Regulatory	5	4	1
Generation Operations	33	9	24
Major Capital Projects	5	1	4
Transmission	38	30	8
Customer Service & Distribution	35	46	(11)
Customer Care & Energy Conservation	18	16	2
Total	179	146	33

*Note - 6 of the 146 projected reduction will be achieved through other cost saving measures. The actual reduction of 179 to the end of December is entirely position reductions.

Section:	Tab 5 Appendix 5.7	Page No.:	PUB/MH I-73 (b)
Topic:	Financial Results & Forecasts		
Subtopic:	OM&A		
Issue:	Accounting Changes		

PREAMBLE TO IR (IF ANY):

MH at the 2012 GRA had reported on total labour and benefits charged to capital for the years 2007/08 through 2011/12. Due to system changes, MH did not provide a break out-of capitalized labour and other charges for the historical years. Based on previously provided information, Board advisors prepared the following chart:

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT (Note 1)

(In thousands of $)	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Wages & Salaries	380,031	407,988	425,158	451,926	466,165	480,511	502,692	524,552	533,997
Overtime	45,890	50,307	50,704	54,757	61,031	62,365	61,709	71,080	73,121
Employee Benefits	83,495	83,013	95,376	104,674	130,886	157,094	160,592	155,892	158,992
Sub-Total	509,416	541,308	571,238	611,357	658,082	699,970	724,993	751,524	766,110
Less: Labour & Benefits Charged to Capital (Note 2)	(185,900)	(193,500)	(207,600)	(221,200)	(215,491)	(234,510)	(256,588)	(282,335)	(287,969)
Labour & Benefits Charged to Operations*	323,516	347,808	363,638	390,157	442,591	465,460	468,405	469,189	478,140
Other Costs									
Employee Safety & Training	4,062	4,284	3,863	3,909	4,463	4,596	5,225	5,188	5,175
Travel Expenses	31,671	32,435	32,594	31,266	31,194	31,915	31,766	31,628	31,634
Motor Vehicle	24,125	24,281	24,436	28,676	29,516	29,670	29,682	29,699	29,699
Materials & Tools	29,338	26,897	28,105	26,101	24,806	27,920	26,700	26,090	26,090
Consulting & Professional Fees	9,136	14,814	11,157	10,250	10,817	14,657	14,349	12,395	12,237
Construction & Maintenance Services	18,000	20,109	22,657	20,750	16,259	16,775	19,364	18,580	18,580
Building & Property Services	28,685	22,931	21,944	21,387	25,644	28,978	27,738	27,297	27,297
Equipment Maintenance & Rentals	13,028	14,379	14,165	13,388	14,680	15,007	16,120	16,191	16,191
Consumer Services	5,230	5,798	5,086	5,225	5,050	5,277	5,323	5,323	5,323
Computer Services	858	983	1,003	861	849	678	985	1,020	1,019
Collection Costs	5,019	4,599	4,497	4,035	4,261	3,125	4,078	4,078	4,078
Customer & Public Relations	6,355	8,155	7,905	8,093	6,731	5,610	5,334	5,344	5,316
Sponsored Memberships	1,464	1,325	1,917	1,608	1,767	1,249	1,764	1,737	1,737
Office & Administration	14,538	15,320	14,316	14,277	13,874	14,724	15,722	15,721	15,717
Communication Systems	1,449	1,772	1,678	1,683	1,817	1,963	1,928	1,928	1,928
Research & Development Costs	3,059	3,952	3,651	2,797	3,372	2,195	2,747	2,747	2,747
Miscellaneous Expense	6,548	1,190	1,264	2,032	2,040	1,485	954	900	900
Contingency Planning					-	-	2,594	2,610	2,657
Operating Expense Recovery	(21,519)	(21,580)	(23,004)	(11,238)	(13,997)	(17,808)	(13,468)	(13,649)	(13,647)
Strategic Initiative Funding							870	3,640	6,317
Sub-Total	181,046	181,644	177,234	185,100	183,143	188,016	199,775	198,467	200,995
Less: Other Costs Charged to Capital (Note 3)	(19,275)	(30,798)	(35,945)	(47,451)	(29,327)	(31,503)	(33,329)	(34,647)	(34,818)
Other Costs Charged to Operations*	181,046	181,644	177,234	185,100	153,816	156,513	166,446	163,820	166,177
Total	**504,562**	**529,452**	**540,872**	**575,257**	**596,407**	**621,973**	**634,851**	**633,009**	**644,317**
Capitalized Overhead	(61,198)	(60,151)	(47,336)	(53,084)	(69,720)	(74,446)	(81,265)	(24,578)	(24,824)
Operating and Administration Charged to Centra	(59,803)	(60,951)	(60,644)	(62,687)	(63,735)	(66,810)	(67,829)	(66,691)	(67,818)
Electric OM&A, including Accounting Changes	**364,286**	**377,552**	**396,947**	**412,035**	**462,952**	**480,717**	**485,757**	**541,740**	**551,675**
Less: Accounting Changes	(9,655)	(13,180)	(32,889)	(36,578)	(78,345)	(91,155)	(93,858)	(145,644)	(151,345)
Electric OM&A, excluding Accounting Changes	**354,631**	**364,372**	**364,058**	**375,457**	**384,607**	**389,562**	**391,899**	**396,096**	**400,330**
Year over Year % Change, including Accounting Changes		3.6%	5.1%	3.8%	12.4%	3.8%	1.0%	11.5%	1.8%
Year over Year % Change, excluding Accounting Changes		**2.7%**	**-0.1%**	**3.1%**	**2.4%**	**1.3%**	**0.6%**	**1.1%**	**1.1%**

*Includes amounts capitalized through Overhead

Notes:
1. Source : PUB/MH I-73 (b) 2015 GRA
2. Source: PUB/MH I-38 (e) 2012 GRA
3. Other costs charged to Capital for 2007/08 to 2011/12 derived based on Total Labour & Expenses Capitalized per MH less Labour and Benefits charged to Capital per PUB/MH I-38 (e) 2012 GRA

	2008/09	2009/10	2010/11	2011/12
Labour & Expense Capitalized	*(205,175)*	*(224,298)*	*(243,545)*	*(268,651)*
Labour & Benefits Charged to Capital PUB/MH I-38 (e) 2012 GRA	*185,900*	*193,500*	*207,600*	*221,200*
Other Costs Charged to Capital	**(19,275)**	**(30,798)**	**(35,945)**	**(47,451)**

QUESTION:

a) Please confirm or update and file the attached chart.

b) Please provide the compound annual growth in each category for the years 2007/08 to 2013/14 and 2013/14 to 2016/17.

c) Please provide the detail of other charges attributable to capital for each of the years 2007 /08 through 2016/17.

RATIONALE FOR QUESTION:

To review Manitoba Hydro's cost control through controlling staffing levels.

RESPONSE:

a) & c)

The data highlighted in the schedule in the question for the years 2008/09 through 2011/12 is not comparable to 2012/13 through 2016/17. In 2012/13 changes were made to activity rates to support the transition to IFRS by excluding costs imbedded in activity rates that would no longer be eligible for capitalization. In addition, modifications were made to overhead rates and Manitoba Hydro's internal cost allocation methodology. These changes were made on a go-forward basis and as a result both Labour and Benefits Charged to Capital and Other Costs Charged to Capital provided in the current filing cannot be restated in the new format prior to 2012/13.

b) The compound annual growth in each category for the years 2007/08 to 2013/14 and 2013/14 to 2016/17 is provided in the following schedule.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

(In thousands of $)	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2007/08-2013/14 Compounded Annual Growth	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	2013/14-2016/17 Compounded Annual Growth
Wages & Salaries	$ 359,249	$ 380,031	$ 407,988	$ 425,158	$ 451,926	$ 466,165	$ 480,511	5.0	$ 502,692	524,552	533,997	3.6
Overtime	41,781	45,890	50,307	50,704	54,757	61,031	62,365	6.9	61,709	71,080	73,121	5.4
Employee Benefits	76,807	83,495	83,013	95,376	104,674	130,886	157,094	12.7	160,592	155,892	158,992	0.4
Sub-Total	477,838	509,417	541,307	571,238	611,357	658,082	699,970	6.6	724,993	751,523	766,109	3.1
Less: Labour & Benefits Charged to Capital						(215,491)	(234,510)		(256,588)	(282,335)	(287,969)	7.1
Labour & Benefits Charged to Operations*	477,838	509,417	541,307	571,238	611,357	442,591	465,460		468,405	469,188	478,140	0.9
Other Costs												
Employee Safety & Training	3,646	4,062	4,284	3,863	3,909	4,463	4,596	3.9	5,225	5,188	5,175	4.0
Travel Expenses	28,331	31,671	32,435	32,594	31,266	31,194	31,915	2.0	31,766	31,628	31,634	(0.3)
Motor Vehicle	22,423	24,125	24,281	24,436	28,676	29,516	29,670	4.8	29,682	29,699	29,699	0.0
Materials & Tools	27,824	29,338	26,897	28,105	26,101	24,806	27,920	0.1	26,700	26,090	26,090	(2.2)
Consulting & Professional Fees	7,503	9,136	14,814	11,157	10,250	10,817	14,657	11.8	14,349	12,395	12,237	(5.8)
Construction & Maintenance Services	15,938	18,000	20,109	22,657	20,750	16,259	16,775	0.9	19,364	18,580	18,580	3.5
Building & Property Services	25,740	28,685	22,931	21,944	21,387	25,644	28,978	2.0	27,738	27,297	27,297	(2.0)
Equipment Maintenance & Rentals	11,719	13,028	14,379	14,165	13,388	14,680	15,007	4.2	16,120	16,191	16,191	2.6
Consumer Services	4,651	5,230	5,798	5,086	5,225	5,050	5,277	2.1	5,323	5,323	5,323	0.3
Computer Services	1,131	858	983	1,003	861	849	678	(8.2)	985	1,020	1,019	14.5
Collection Costs	5,256	5,019	4,599	4,497	4,035	4,261	3,125	(8.3)	4,078	4,078	4,078	9.3
Customer & Public Relations	6,664	6,355	8,155	7,905	8,093	6,731	5,610	(2.8)	5,334	5,344	5,316	(1.8)
Sponsored Memberships	1,192	1,464	1,325	1,917	1,608	1,767	1,249	0.8	1,764	1,737	1,737	11.6
Office & Administration	14,427	14,538	15,320	14,316	14,277	13,874	14,724	0.3	15,722	15,721	15,717	2.2
Communication Systems	1,353	1,449	1,772	1,678	1,683	1,817	1,963	6.4	1,928	1,928	1,928	(0.6)
Research & Development Costs	2,979	3,059	3,952	3,651	2,797	3,372	2,195	(5.0)	2,747	2,747	2,747	7.8
Miscellaneous Expense	3,292	6,548	1,190	1,264	2,032	2,040	1,485	(12.4)	954	900	900	(15.4)
Contingency Planning						-	-	0.0	2,594	2,610	2,657	
Operating Expense Recovery	(23,314)	(21,519)	(21,580)	(23,004)	(11,238)	(13,997)	(17,808)	(4.4)	(13,468)	(13,649)	(13,647)	(8.5)
Strategic Initiative Funding									870	3,640	6,317	
Sub-Total	160,756	181,047	181,644	177,233	185,100	183,143	188,016	2.6	199,774	198,468	200,994	2.2
Less: Other Costs Charged to Capital						(29,327)	(31,503)		(33,329)	(34,647)	(34,818)	3.4
Other Costs Charged to Operations*	160,756	181,047	181,644	177,233	185,100	153,815	156,513		166,444	163,821	166,177	2.0
Total	**638,594**	**690,463**	**722,951**	**748,471**	**796,457**	**596,406**	**621,973**		**634,849**	**633,009**	**644,317**	**1.2**
Less:												
Labour & Expense Capitalized	(192,338)	(205,175)	(224,298)	(243,545)	(268,651)							
Capitalized Overhead	(67,289)	(61,198)	(60,151)	(47,336)	(53,084)	(69,720)	(74,446)	1.7	(81,265)	(24,578)	(24,824)	(30.7)
Operating and Administration Charged to Centra	(56,270)	(59,803)	(60,951)	(60,644)	(62,687)	(63,735)	(66,810)	2.9	(67,829)	(66,691)	(67,818)	0.5
Electric OM&A, including Accounting Changes	**322,696**	**364,287**	**377,551**	**396,946**	**412,035**	**462,952**	**480,717**	**6.9**	**485,755**	**541,740**	**551,675**	**4.7**
Less: Accounting Changes		(9,655)	(13,180)	(32,889)	(36,578)	(78,345)	(91,155)	56.7	(93,858)	(145,644)	(151,345)	18.4
Electric OM&A, excluding Accounting Changes	**$ 322,696**	**$ 354,632**	**$ 364,371**	**$ 364,057**	**$ 375,457**	**$ 384,607**	**$ 389,562**	**3.2**	**$ 391,897**	**$ 396,096**	**$ 400,330**	**0.9**

*Includes amounts capitalized through Overhead

As shown in the following schedule, Manitoba Hydro has maintained the compounded annual growth for 2012/13 to 2016/17, to below inflationary levels at 1% excluding accounting changes.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

(In thousands of $)	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	2012/13-2016/17 Compounded Annual Growth
Wages & Salaries	$ 466,165	$ 480,511	$ 502,692	524,552	533,997	3.5
Overtime	61,031	62,365	61,709	71,080	73,121	4.6
Employee Benefits	130,886	157,094	160,592	155,892	158,992	5.0
Sub-Total	658,082	699,970	724,993	751,523	766,109	3.9
Less: Labour & Benefits Charged to Capital	(215,491)	(234,510)	(256,588)	(282,335)	(287,969)	7.5
Labour & Benefits Charged to Operations*	442,591	465,460	468,405	469,188	478,140	2.0
Other Costs						
Employee Safety & Training	4,463	4,596	5,225	5,188	5,175	3.8
Travel Expenses	31,194	31,915	31,766	31,628	31,634	0.4
Motor Vehicle	29,516	29,670	29,682	29,699	29,699	0.2
Materials & Tools	24,806	27,920	26,700	26,090	26,090	1.3
Consulting & Professional Fees	10,817	14,657	14,349	12,395	12,237	3.1
Construction & Maintenance Services	16,259	16,775	19,364	18,580	18,580	3.4
Building & Property Services	25,644	28,978	27,738	27,297	27,297	1.6
Equipment Maintenance & Rentals	14,680	15,007	16,120	16,191	16,191	2.5
Consumer Services	5,050	5,277	5,323	5,323	5,323	1.3
Computer Services	849	678	985	1,020	1,019	4.7
Collection Costs	4,261	3,125	4,078	4,078	4,078	(1.1)
Customer & Public Relations	6,731	5,610	5,334	5,344	5,316	(5.7)
Sponsored Memberships	1,767	1,249	1,764	1,737	1,737	(0.4)
Office & Administration	13,874	14,724	15,722	15,721	15,717	3.2
Communication Systems	1,817	1,963	1,928	1,928	1,928	1.5
Research & Development Costs	3,372	2,195	2,747	2,747	2,747	(5.0)
Miscellaneous Expense	2,040	1,485	954	900	900	(18.5)
Contingency Planning	-	-	2,594	2,610	2,657	
Operating Expense Recovery	(13,997)	(17,808)	(13,468)	(13,649)	(13,647)	(0.6)
Strategic Initiative Funding			870	3,640	6,317	
Sub-Total	183,143	188,016	199,774	198,468	200,994	2.4
Less: Other Costs Charged to Capital	(29,327)	(31,503)	(33,329)	(34,647)	(34,818)	4.4
Other Costs Charged to Operations*	153,815	156,513	166,444	163,821	166,177	2.0
Total	**596,406**	**621,973**	**634,849**	**633,009**	**644,317**	**2.0**
Less:						
Labour & Expense Capitalized						
Capitalized Overhead	(69,720)	(74,446)	(81,265)	(24,578)	(24,824)	(22.8)
Operating and Administration Charged to Centra	(63,735)	(66,810)	(67,829)	(66,691)	(67,818)	1.6
Electric OM&A, including Accounting Changes	**462,952**	**480,717**	**485,755**	**541,740**	**551,675**	**4.5**
Less: Accounting Changes	(78,345)	(91,155)	(93,858)	(145,644)	(151,345)	17.9
Electric OM&A, excluding Accounting Changes	**$ 384,607**	**$ 389,562**	**$ 391,897**	**$ 396,096**	**$ 400,330**	**1.0**

*Includes amounts capitalized through Overhead

Section:	Tab 5, [Appendix 5.4 p. 6]	**Page No.:**	PUB/MH I-31 (c)/ PUB/MH I-73 (d) & 74 (a)
Topic:	Financial Results and Forecast		
Subtopic:	OM&A Expense		
Issue:	Accounting Changes		

PREAMBLE TO IR (IF ANY):

At the last GRA, MH had provided a forecast of the impact of IFRS on capitalization of administrative costs at $38 million. The detail of the forecast impact based on IFF11-2 was $37 million in 2016 going to $43 million in 2024, peaking at $49 million in 2029. (PUB/MH I-09 (e) 2012 GRA) MH now forecasts this same group of ineligible administrative overhead costs to be $55 million in 2016 and grow to $60 million in 2024, peaking at $67 million in 2029.

Additional Costs Ineligible for Capitalization upon Transition to IFRS
Comparison 2014 vs 2012 IFRS Status Update Report
(In millions of dollars):

	2014 Rpt	2012 Rpt	Difference	% Δ
Technical and Soft Skills Training	17	11	6	55%
Service Areas (Management accounting, Treasury, HR, Safety, etc)	13	9	4	44%
Administrative & Clerical Support Staff	13	9	4	44%
Division and Department Manager	14	7	7	100%
Fleet & Stores Administration	1	2	-1	-50%
Total	58	38	20	53%

QUESTION:

a) Please explain why forecast administrative overhead costs that are now being expensed on transition to IFRS have grown to $58 million in 2015/16 from $37 million for that year at the last GRA.

b) Please explain why Technical and Soft Skill Training increased by 55%, Service Areas by 44%, Administrative and Clerical Support Staff by 44%, Division and Dept manager by 100% from what was indicated at the last GRA.

c) Please provide a schedule of all costs incurred related to the administrative overhead costs in the above table for the years 2007/08 through 2014/15 and comment on the changes.

d) Please file any updated working papers prepared internally or by MH's IFRS consultant on administrative overhead costs that are not eligible for capitalization that supports the increases in the test years.

RATIONALE FOR QUESTION:

To explore the impact of IFRS on the capitalization of administrative costs.

RESPONSE:

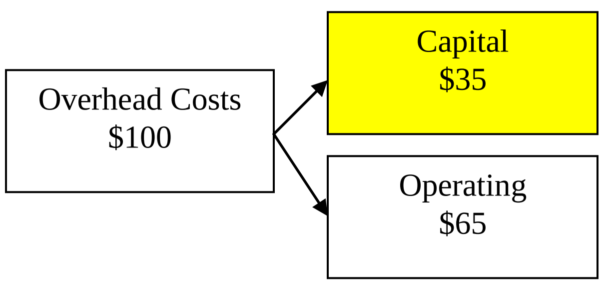
Parts a) & b):

The total overhead costs incurred in each of the categories (i.e. Technical & Softskills Training, Service Areas, Administrative & Clerical Support and Division & Department Managers) have not significantly changed since the last estimate was provided. The $20 million increase in ineligible overhead includes approximately $3 to $4 million attributable to higher wages and salaries as a result of contract settlements. The remainder of the $20 million increase in ineligible overhead is due to a greater proportion of overhead costs being allocated to capital as a result of higher levels of construction activity experienced since the last estimate was provided. The following illustrative example demonstrates how changes in the level of capital activity directly impact the allocation of overhead costs between operating and capital.

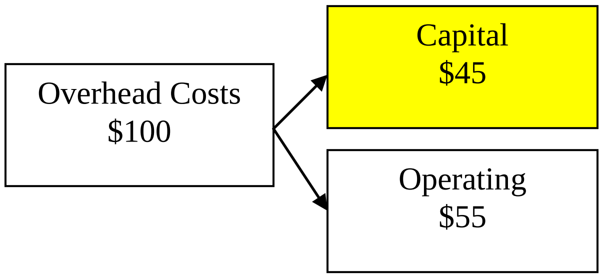
<u>Illustrative Example</u>

Total Overhead Costs = $100

Staff deployment is 35% to capital construction and 65% to operations and maintenance.



Total Overhead Costs = $100
Staff deployment is 45% to capital construction and 55% to operations and maintenance.



In 2015/16 under IFRS, the costs previously charged to capital are no longer eligible for capitalization and must be expensed. As per the illustrative example above, the $45 of overhead costs charged to capital would be deemed ineligible under IFRS as compared to the $35 originally estimated.

Part c):
In IFF14, Manitoba Hydro has assumed that IFRS is not required until the 2015/16 fiscal year. As such, Manitoba Hydro has not conducted a comprehensive analysis of IFRS changes on a retrospective basis back to 2007/08 for the costs incurred related to the administrative overhead costs in the above table.

Part d):
The following table provides an estimate of the overhead costs and the proportionate allocation to capital and operating. In 2015/16 under IFRS, the $58 million of overhead costs previously charged to capital must be expensed.

Description of Overhead Costs (in millions of dollars)	Total Overhead Costs	Overhead Capitalized	Overhead Expensed
Technical and Softskills Training	$ 37	$ 17	$ 20
Service Areas	29	13	16
Administrative & Clerical Support Staff	28	13	15
Division and Department Manager	31	14	17
Fleet and Stores Administration	3	1	2
Total	**$ 127**	**$ 58**	**$ 69**

Section:	Tab 11: App 11.8	**Page No.:**	PUB/MH I-76
Topic:	Minimum Filing Requirements		
Subtopic:	Financial Results		
Issue:	Impact of Rate Increases		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please refile the Schedule reflecting the following four scenarios – a 2% and 3% rate increase in 2015/16, each with depreciation expense as proposed and based on 2014 ASL without net salvage.

RATIONALE FOR QUESTION:

To assess the impact of alternative rate increases.

RESPONSE:

The following schedules provide the updates to PUB/MH I-76 for the requested scenarios.

Scenario 1: 2% April 1, 2015

- Results in even annual increases of 4.18% from 2017-2031 to achieve 25% Equity in 2034 consistent with MH14.

Scenario 2: 3% April 1, 2015

- Results in even annual increases of 4.06% from 2017-2031 to achieve 25% Equity in 2034 consistent with MH14.

Scenario 3: 2% April 1, 2015 and ASL depreciation without net salvage

- Results in even annual increases of 4.14% from 2017-2031 to achieve 25% Equity in 2034 consistent with MH14

Scenario 4: 3% April 1, 2015 and ASL depreciation without net salvage

- Results in even annual increases of 4.02% from 2017-2031 to achieve 25% Equity in 2034 consistent with MH14

Please note that the CGAAP ASL scenarios with net salvage include the rate deferral account amortization as discussed in PUB/MH-II-21a-c.

Please see the response to PUB/MH-II-21a-c for a discussion regarding the impacts associated with using the CGAAP ASL method for rate setting purposes.

Net Income - Electricity Operations (Scenario 1: 2% April 1, 2015)

(in millions of $)	2013	2014	Forecast 2015	2016	2017
Revenue					
General Consumers Revenue					
- at approved rates	$ 1 341	$ 1 424	$ 1 401	$ 1 415	$ 1 421
- Bipole III Reserve	-	(19)	(30)	(32)	(33)
Extraprovincial Revenue (net of Fuel & Power Purchased and Water Rentals)	101	137	150	181	147
Other Revenue	30	22	15	14	14
	1 472	1 564	1 537	1 578	1 549
Expenses	1 407	1 439	1 495	1 571	1 655
Operating, Maintenance and Administrative	463	481	486	542	552
Finance Expense	452	435	495	511	550
Depreciation and Amortization	392	411	405	401	422
Capital and Other Taxes	86	97	99	107	121
Corporate Allocation	9	9	9	8	8
Other expenses	5	6	2	2	2
Non-controlling Interest	13	22	25	12	8
Net Income (loss) before alternate rate increases	$ 78	$ 147	$ 67	$ 19	$ (99)
Alternate rate increases (2.75% May 1, 2014, 2.00% April 1, 2015, and 4.18% April 1, 2016)			35	68	131
Net Income including alternate rate increases	$ 78	$ 147	$ 102	$ 87	$ 32

Retained Earnings and Financial Ratios (without alternate rate increases)

	2013	2014	2015	2016	2017
Retained Earnings (electric operations)	$ 2 468	$ 2 615	$ 2 681	$ 2 646	$ 2 549
Debt to Equity Ratio (electric operations)	75:25	77:23	78:22	83:17	85:15
Interest Coverage Ratio (electric operations)	1.13	1.25	1.11	1.03	0.88
Capital Coverage Ratio (electric operations)	1.26	1.39	0.92	0.84	0.66

Retained Earnings and Financial Ratios (including alternate rate increases)

	2013	2014	2015	2016	2017
Retained Earnings (electric operations)	$ 2 468	$ 2 615	$ 2 717	$ 2 750	$ 2 782
Debt to Equity Ratio (electric operations)	75:25	77:23	78:22	82:18	84:16
Interest Coverage Ratio (electric operations)	1.13	1.25	1.16	1.12	1.04
Capital Coverage Ratio (electric operations)	1.26	1.39	0.98	0.97	0.89

Net Income - Electricity Operations (Scenario 2: 3% April 1, 2015/16)

(in millions of $)	2013	2014	2015 (Forecast)	2016 (Forecast)	2017 (Forecast)
Revenue					
General Consumers Revenue					
- at approved rates	$ 1 341	$ 1 424	$ 1 401	$ 1 415	$ 1 421
- Bipole III Reserve	-	(19)	(30)	(32)	(33)
Extraprovincial Revenue (net of Fuel & Power Purchased and Water Rentals)	101	137	150	181	147
Other Revenue	30	22	15	14	14
	1 472	1 564	1 537	1 578	1 548
Expenses	1 407	1 439	1 495	1 571	1 654
Operating, Maintenance and Administrative	463	481	486	542	552
Finance Expense	452	435	495	510	549
Depreciation and Amortization	392	411	405	401	422
Capital and Other Taxes	86	97	99	107	121
Corporate Allocation	9	9	9	8	8
Other expenses	5	6	2	2	2
Non-controlling Interest	13	22	25	12	8
Net Income (loss) before alternate rate increases	$ 78	$ 147	$ 67	$ 19	$ (98)
Alternate rate increases (2.75% May 1, 2014, 3.00% April 1, 2015, and 4.06% April 1, 2016)			35	83	144
Net Income including alternate rate increases	$ 78	$ 147	$ 102	$ 102	$ 46

Retained Earnings and Financial Ratios (without alternate rate increases)

	2013	2014	2015	2016	2017
Retained Earnings (electric operations)	$ 2 468	$ 2 615	$ 2 681	$ 2 646	$ 2 549
Debt to Equity Ratio (electric operations)	75:25	77:23	78:22	83:17	85:15
Interest Coverage Ratio (electric operations)	1.13	1.25	1.11	1.03	0.88
Capital Coverage Ratio (electric operations)	1.26	1.39	0.92	0.84	0.66

Retained Earnings and Financial Ratios (including alternate rate increases)

	2013	2014	2015	2016	2017
Retained Earnings (electric operations)	$ 2 468	$ 2 615	$ 2 717	$ 2 765	$ 2 810
Debt to Equity Ratio (electric operations)	75:25	77:23	78:22	82:18	84:16
Interest Coverage Ratio (electric operations)	1.13	1.25	1.16	1.14	1.05
Capital Coverage Ratio (electric operations)	1.26	1.39	0.98	0.99	0.92

Net Income - Electricity Operations (Scenario 3: 2% April 1, 2015 & ASL Depreciation without Net Salvage)

(in millions of $)	2013	2014	2015 Forecast	2016 Forecast	2017 Forecast
Revenue					
General Consumers Revenue					
- at approved rates	$ 1 341	$ 1 424	$ 1 401	$ 1 415	$ 1 421
- Bipole III Reserve	-	(19)	(30)	(32)	(33)
Extraprovincial Revenue (net of Fuel & Power Purchased and Water Rentals)	101	137	150	181	147
Other Revenue	30	22	15	14	14
	1 472	1 564	1 537	1 578	1 549
Expenses	1 407	1 439	1 495	1 543	1 628
Operating, Maintenance and Administrative	463	481	486	542	552
Finance Expense	452	435	495	511	550
Depreciation and Amortization	392	411	405	372	395
Capital and Other Taxes	86	97	99	107	121
Corporate Allocation	9	9	9	8	8
Other expenses	5	6	2	2	2
Non-controlling Interest	13	22	25	12	8
Net Income (loss) before alternate rate increases	$ 78	$ 147	$ 67	$ 48	$ (72)
Alternate rate increases (2.75% May 1, 2014, 2.00% April 1, 2015, and 4.14% April 1, 2016)			35	68	130
Net Income including alternate rate increases	$ 78	$ 147	$ 102	$ 116	$ 58

Retained Earnings and Financial Ratios (without alternate rate increases)

	2013	2014	2015	2016	2017
Retained Earnings (electric operations)	$ 2 468	$ 2 615	$ 2 681	$ 2 646	$ 2 549
Debt to Equity Ratio (electric operations)	75:25	77:23	78:22	83:17	85:15
Interest Coverage Ratio (electric operations)	1.13	1.25	1.11	1.03	0.88
Capital Coverage Ratio (electric operations)	1.26	1.39	0.92	0.84	0.66

Retained Earnings and Financial Ratios (including alternate rate increases)

	2013	2014	2015	2016	2017
Retained Earnings (electric operations)	$ 2 468	$ 2 615	$ 2 717	$ 2 812	$ 2 870
Debt to Equity Ratio (electric operations)	75:25	77:23	78:22	82:18	84:16
Interest Coverage Ratio (electric operations)	1.13	1.25	1.16	1.16	1.07
Capital Coverage Ratio (electric operations)	1.26	1.39	0.98	0.97	0.89

Net Income - Electricity Operations (Scenario 4: 3% April 1, 2015 & ASL Depreciation without Net Salvage)

(in millions of $)	2013	2014	2015 (Forecast)	2016 (Forecast)	2017 (Forecast)
Revenue					
General Consumers Revenue					
- at approved rates	$ 1 341	$ 1 424	$ 1 401	$ 1 415	$ 1 421
- Bipole III Reserve	-	(19)	(30)	(32)	(33)
Extraprovincial Revenue (net of Fuel & Power Purchased and Water Rentals)	101	137	150	181	147
Other Revenue	30	22	15	14	14
	1 472	1 564	1 537	1 578	1 548
Expenses	1 407	1 439	1 495	1 542	1 627
Operating, Maintenance and Administrative	463	481	486	542	552
Finance Expense	452	435	495	510	549
Depreciation and Amortization	392	411	405	372	395
Capital and Other Taxes	86	97	99	107	121
Corporate Allocation	9	9	9	8	8
Other expenses	5	6	2	2	2
Non-controlling Interest	13	22	25	12	8
Net Income (loss) before alternate rate increases	$ 78	$ 147	$ 67	$ 48	$ (71)
Alternate rate increases (2.75% May 1, 2014, 3.00% April 1, 2015, and 4.02% April 1, 2016)			35	83	143
Net Income including alternate rate increases	$ 78	$ 147	$ 102	$ 131	$ 72

Retained Earnings and Financial Ratios (without alternate rate increases)

	2013	2014	2015	2016	2017
Retained Earnings (electric operations)	$ 2 468	$ 2 615	$ 2 681	$ 2 646	$ 2 549
Debt to Equity Ratio (electric operations)	75:25	77:23	78:22	83:17	85:15
Interest Coverage Ratio (electric operations)	1.13	1.25	1.11	1.03	0.88
Capital Coverage Ratio (electric operations)	1.26	1.39	0.92	0.84	0.66

Retained Earnings and Financial Ratios (including alternate rate increases)

	2013	2014	2015	2016	2017
Retained Earnings (electric operations)	$ 2 468	$ 2 615	$ 2 717	$ 2 827	$ 2 899
Debt to Equity Ratio (electric operations)	75:25	77:23	78:22	82:18	83:17
Interest Coverage Ratio (electric operations)	1.13	1.25	1.16	1.18	1.08
Capital Coverage Ratio (electric operations)	1.26	1.39	0.98	0.99	0.91

ELECTRIC OPERATIONS (PUB_MH_II_45_2pct_ELG without Salvage)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 401	1 415	1 421	1 443	1 450	1 461	1 466	1 473	1 485	1 496
additional*	35	68	131	198	268	343	420	501	588	680
BPIII Reserve Account	(30)	(32)	(33)	(35)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 900	1 982	2 077	2 201	2 333	2 717	2 933	3 047	3 180
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	511	550	586	757	894	1 202	1 335	1 345	1 361
Depreciation and Amortization	405	401	422	445	521	525	613	667	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	144	150	150	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 825	1 958	2 048	2 322	2 478	2 929	3 160	3 250	3 315
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	87	32	37	(115)	(141)	(202)	(227)	(204)	(139)
* Additional General Consumers Revenue										
Percent Increase	2.75%	2.00%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%
Cumulative Percent Increase	2.75%	4.81%	9.19%	13.75%	18.51%	23.46%	28.63%	34.01%	39.61%	45.45%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	13%	12%	10%	9%	9%
Interest Coverage	1.16	1.12	1.04	1.04	0.90	0.89	0.85	0.83	0.85	0.90
Capital Coverage	0.98	0.97	0.89	1.05	0.84	0.76	0.77	0.91	1.06	1.20

ELECTRIC OPERATIONS (PUB_MH_II_45_2pct_ELG without Salvage)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	1 510	1 524	1 537	1 551	1 564	1 580	1 597	1 614	1 632	1 650
additional*	778	882	991	1 106	1 228	1 359	1 497	1 576	1 658	1 743
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3 300	3 350	3 489	3 596	3 730	3 885	4 024	4 111	4 192	4 297
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 364	1 361	1 351	1 351	1 335	1 312	1 274	1 206	1 169	1 122
Depreciation and Amortization	767	780	791	804	811	820	831	842	857	873
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	162	163	164	165	166	167	168	170	173	174
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3 358	3 378	3 401	3 429	3 444	3 450	3 442	3 412	3 410	3 409
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(63)	(30)	85	161	280	424	570	684	765	868
* Additional General Consumers Revenue										
Percent Increase	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	2.00%	2.00%	2.00%
Cumulative Percent Increase	51.53%	57.86%	64.47%	71.34%	78.51%	85.97%	93.75%	97.62%	101.58%	105.61%
Financial Ratios										
Equity	9%	9%	9%	10%	11%	13%	16%	18%	22%	25%
Interest Coverage	0.95	0.98	1.06	1.12	1.21	1.32	1.44	1.56	1.64	1.75
Capital Coverage	1.25	1.31	1.48	1.59	1.71	1.97	2.08	2.25	2.34	2.47

ELECTRIC OPERATIONS (PUB_MH_II_45_2pct_ELG without Salvage)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 296	2 599	2 729	2 167	2 239	2 444
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 586	27 670	28 300	27 727	27 789	27 967
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 377	22 106	22 792	23 155	23 450	23 641
Current and Other Liabilities	2 016	2 180	2 154	3 154	2 126	2 591	2 764	2 084	2 026	2 114
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	80	114	149	160	107	53	-	-	-
Retained Earnings	2 717	2 750	2 782	2 818	2 703	2 562	2 360	2 133	1 929	1 790
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 586	27 670	28 300	27 727	27 789	27 967

ELECTRIC OPERATIONS (PUB_MH_II_45_2pct_ELG without Salvage)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823	42 952
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 384)	(17 200)	(18 031)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 710	24 666	24 623	24 921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 389	2 539	2 791	3 189	3 432	3 808	3 698	4 394	5 108	5 891
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27 917	28 065	28 306	28 673	28 895	29 226	29 099	29 781	30 512	31 377
LIABILITIES AND EQUITY										
Long-Term Debt	23 595	24 398	24 601	24 743	24 676	23 949	23 939	23 943	23 937	23 581
Current and Other Liabilities	2 135	1 471	1 389	1 415	1 388	1 984	1 259	1 215	1 148	1 462
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	1 727	1 697	1 781	1 942	2 221	2 645	3 214	3 897	4 662	5 529
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 917	28 065	28 306	28 673	28 895	29 226	29 099	29 781	30 512	31 377

ELECTRIC OPERATIONS (PUB_MH_II_45_2pct_ELG without Salvage)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 929	2 013	2 110	2 210	2 331	2 714	2 930	3 044	3 177
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 069)	(1 098)	(1 123)	(1 155)
Interest Paid	(511)	(514)	(547)	(593)	(786)	(934)	(1 233)	(1 355)	(1 340)	(1 353)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	559	545	575	459	416	444	505	596	685
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 990	1 600	1 390	800	560	580
Sinking Fund Withdrawals	110	21	-	8	448	205	295	717	165	28
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 213	1 471	734	774	243	286
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(242)	(246)	(264)	(358)	(254)	(260)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 517)	(1 831)	(1 303)	(1 144)	(982)	(988)
Net Increase (Decrease) in Cash	(270)	(106)	58	(76)	155	56	(126)	135	(143)	(16)
Cash at Beginning of Year	133	(137)	(243)	(185)	(261)	(106)	(50)	(176)	(41)	(185)
Cash at End of Year	(137)	(243)	(185)	(261)	(106)	(50)	(176)	(41)	(185)	(201)

ELECTRIC OPERATIONS (PUB_MH_II_45_2pct_ELG without Salvage)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 297	3 348	3 486	3 593	3 727	3 881	4 021	4 107	4 189	4 293
Cash Paid to Suppliers and Employees	(1 179)	(1 189)	(1 211)	(1 225)	(1 247)	(1 269)	(1 288)	(1 313)	(1 334)	(1 363)
Interest Paid	(1 361)	(1 363)	(1 367)	(1 382)	(1 386)	(1 372)	(1 352)	(1 260)	(1 239)	(1 207)
Interest Received	20	22	35	49	62	72	84	64	78	93
	777	817	944	1 034	1 156	1 312	1 466	1 598	1 695	1 818
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	390	780	190	190	(20)	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	299	105	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	256	405	161	163	(45)	(22)	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(273)	(272)	(280)	(293)	(307)	(316)	(323)	(301)	(312)	(323)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 047)	(1 053)	(1 058)	(1 064)	(1 095)	(1 089)	(1 136)	(1 127)	(1 185)	(1 277)
Net Increase (Decrease) in Cash	(14)	168	47	133	16	201	288	412	464	494
Cash at Beginning of Year	(201)	(215)	(47)	0	133	149	350	639	1 051	1 515
Cash at End of Year	(215)	(47)	0	133	149	350	639	1 051	1 515	2 009

ELECTRIC OPERATIONS (PUB_MH_II_45_3pct_ELG without Salvage)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 401	1 415	1 421	1 443	1 450	1 461	1 466	1 473	1 485	1 496
additional*	35	83	144	211	279	352	427	506	591	681
BPIII Reserve Account	(30)	(32)	(33)	(35)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 914	1 995	2 089	2 212	2 342	2 724	2 938	3 050	3 180
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	549	584	754	890	1 198	1 330	1 339	1 355
Depreciation and Amortization	405	401	422	445	521	525	613	667	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	144	150	150	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	1 957	2 046	2 320	2 474	2 925	3 155	3 245	3 309
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	102	46	50	(103)	(128)	(191)	(216)	(196)	(132)
* Additional General Consumers Revenue										
Percent Increase	2.75%	3.00%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%
Cumulative Percent Increase	2.75%	5.83%	10.13%	14.59%	19.24%	24.08%	29.12%	34.36%	39.81%	45.48%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	13%	12%	10%	10%	9%
Interest Coverage	1.16	1.14	1.05	1.05	0.91	0.90	0.85	0.84	0.86	0.90
Capital Coverage	0.98	0.99	0.92	1.07	0.86	0.79	0.81	0.93	1.07	1.21

ELECTRIC OPERATIONS (PUB_MH_II_45_3pct_ELG without Salvage)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	1 510	1 524	1 537	1 551	1 564	1 580	1 597	1 614	1 632	1 650
additional*	776	876	983	1 094	1 212	1 338	1 472	1 550	1 631	1 715
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3 298	3 345	3 481	3 584	3 714	3 864	3 999	4 085	4 166	4 269
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 357	1 354	1 343	1 343	1 327	1 304	1 267	1 200	1 163	1 118
Depreciation and Amortization	767	780	791	804	811	820	831	842	857	873
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	162	163	164	165	166	167	168	170	172	174
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3 351	3 371	3 394	3 422	3 436	3 443	3 435	3 406	3 405	3 405
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(58)	(28)	84	157	272	412	552	664	744	846
* Additional General Consumers Revenue										
Percent Increase	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	2.00%	2.00%	2.00%
Cumulative Percent Increase	51.38%	57.52%	63.92%	70.57%	77.49%	84.69%	92.18%	96.02%	99.94%	103.94%
Financial Ratios										
Equity	9%	9%	10%	10%	12%	14%	16%	19%	22%	25%
Interest Coverage	0.96	0.98	1.06	1.11	1.20	1.31	1.43	1.54	1.62	1.73
Capital Coverage	1.25	1.31	1.48	1.59	1.70	1.95	2.06	2.22	2.31	2.44

ELECTRIC OPERATIONS (PUB_MH_II_45_3pct_ELG without Salvage)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 296	2 599	2 728	2 167	2 238	2 442
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 586	27 669	28 299	27 727	27 788	27 966
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 906	22 792	22 955	23 450	23 641
Current and Other Liabilities	2 016	2 165	2 124	3 111	2 269	2 721	2 684	2 194	1 927	2 008
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	114	150	161	107	54	-	-	-
Retained Earnings	2 717	2 765	2 810	2 861	2 758	2 630	2 439	2 223	2 027	1 895
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 586	27 669	28 299	27 727	27 788	27 966

ELECTRIC OPERATIONS (PUB_MH_II_45_3pct_ELG without Salvage)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823	42 952
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 384)	(17 200)	(18 031)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 710	24 666	24 623	24 921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 388	2 537	2 789	3 097	3 332	3 695	3 567	4 244	4 937	5 697
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27 915	28 064	28 304	28 581	28 795	29 113	28 969	29 631	30 341	31 184
LIABILITIES AND EQUITY										
Long-Term Debt	23 595	24 198	24 401	24 543	24 476	23 749	23 739	23 743	23 737	23 381
Current and Other Liabilities	2 024	1 559	1 476	1 417	1 389	1 986	1 261	1 217	1 150	1 464
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	1 837	1 809	1 892	2 048	2 319	2 730	3 282	3 945	4 689	5 534
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 915	28 064	28 304	28 581	28 795	29 113	28 969	29 631	30 341	31 184

ELECTRIC OPERATIONS (PUB_MH_II_45_3pct_ELG without Salvage)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 944	2 026	2 122	2 220	2 340	2 721	2 935	3 047	3 178
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 069)	(1 099)	(1 123)	(1 155)
Interest Paid	(511)	(514)	(547)	(593)	(785)	(929)	(1 221)	(1 350)	(1 335)	(1 347)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	573	558	587	471	430	463	515	604	692
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 600	1 590	600	760	580
Sinking Fund Withdrawals	110	21	-	8	448	205	294	717	165	27
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 470	933	574	443	285
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(246)	(263)	(358)	(253)	(259)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 516)	(1 831)	(1 303)	(1 144)	(981)	(986)
Net Increase (Decrease) in Cash	(270)	(91)	71	(64)	(32)	70	94	(55)	66	(10)
Cash at Beginning of Year	133	(137)	(228)	(157)	(221)	(253)	(183)	(90)	(145)	(79)
Cash at End of Year	(137)	(228)	(157)	(221)	(253)	(183)	(90)	(145)	(79)	(89)

ELECTRIC OPERATIONS (PUB_MH_II_45_3pct_ELG without Salvage)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 295	3 342	3 478	3 581	3 711	3 861	3 996	4 081	4 163	4 266
Cash Paid to Suppliers and Employees	(1 179)	(1 189)	(1 211)	(1 225)	(1 247)	(1 269)	(1 288)	(1 313)	(1 334)	(1 362)
Interest Paid	(1 356)	(1 358)	(1 359)	(1 374)	(1 378)	(1 364)	(1 344)	(1 253)	(1 232)	(1 201)
Interest Received	20	22	35	49	62	71	84	63	78	93
	779	817	943	1 030	1 148	1 300	1 448	1 578	1 674	1 795
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	390	580	190	190	(20)	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	297	104	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	255	204	161	163	(45)	(22)	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(272)	(271)	(279)	(292)	(305)	(313)	(321)	(298)	(310)	(320)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 046)	(1 052)	(1 057)	(1 063)	(1 093)	(1 087)	(1 134)	(1 125)	(1 182)	(1 275)
Net Increase (Decrease) in Cash	(12)	(32)	47	130	10	191	273	395	445	474
Cash at Beginning of Year	(89)	(101)	(132)	(85)	45	55	246	519	914	1 359
Cash at End of Year	(101)	(132)	(85)	45	55	246	519	914	1 359	1 834

ELECTRIC OPERATIONS (PUB_MH_II_45_2pct_CGAAP ASL without Salvage)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 401	1 415	1 421	1 443	1 450	1 461	1 466	1 473	1 485	1 496
additional*	35	68	130	197	267	340	416	496	583	674
BPIII Reserve Account	(30)	(32)	(33)	(35)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 900	1 982	2 076	2 199	2 331	2 713	2 928	3 042	3 173
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	511	550	586	757	894	1 203	1 336	1 346	1 363
Depreciation and Amortization	405	372	395	419	492	495	582	638	713	735
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	135	144	145	145	151	151	162
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 796	1 931	2 023	2 294	2 449	2 899	3 133	3 229	3 301
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	116	58	61	(89)	(115)	(175)	(205)	(189)	(131)
* Additional General Consumers Revenue										
Percent Increase	2.75%	2.00%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%
Cumulative Percent Increase	2.75%	4.81%	9.15%	13.67%	18.38%	23.28%	28.39%	33.71%	39.25%	45.01%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	13%	12%	11%	10%	10%
Interest Coverage	1.16	1.16	1.07	1.06	0.92	0.91	0.87	0.85	0.86	0.91
Capital Coverage	0.98	0.97	0.89	1.05	0.83	0.75	0.77	0.90	1.05	1.18

ELECTRIC OPERATIONS (PUB_MH_II_45_2pct_CGAAP ASL without Salvage)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	1 510	1 524	1 537	1 551	1 564	1 580	1 597	1 614	1 632	1 650
additional*	770	873	981	1 094	1 214	1 343	1 480	1 558	1 640	1 724
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3 293	3 341	3 479	3 584	3 716	3 869	4 007	4 093	4 174	4 278
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 366	1 365	1 354	1 355	1 339	1 319	1 283	1 217	1 181	1 135
Depreciation and Amortization	757	768	782	796	805	815	826	836	850	867
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	163	164	165	166	167	169	170	171	174	176
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3 351	3 372	3 397	3 427	3 443	3 453	3 448	3 418	3 418	3 418
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(64)	(32)	79	152	267	407	547	659	739	841
* Additional General Consumers Revenue										
Percent Increase	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	2.00%	2.00%	2.00%
Cumulative Percent Increase	51.02%	57.28%	63.79%	70.58%	77.64%	85.00%	92.67%	96.52%	100.45%	104.46%
Financial Ratios										
Equity	10%	10%	10%	11%	12%	14%	16%	19%	22%	25%
Interest Coverage	0.95	0.98	1.06	1.11	1.20	1.30	1.42	1.53	1.61	1.72
Capital Coverage	1.24	1.28	1.46	1.57	1.69	1.94	2.04	2.21	2.30	2.43

ELECTRIC OPERATIONS (PUB_MH_II_45_2pct_CGAAP ASL without Salvage)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 296	2 599	2 729	2 167	2 239	2 444
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	340	403	468	541	595	640	666	673	673
	16 993	18 928	21 891	25 077	26 731	27 844	28 506	27 962	28 047	28 242
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 377	22 106	22 792	23 155	23 450	23 641
Current and Other Liabilities	2 016	2 180	2 155	3 157	2 132	2 601	2 779	2 105	2 055	2 153
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	80	114	149	160	107	53	-	-	-
Retained Earnings	2 717	2 812	2 870	2 930	2 841	2 726	2 551	2 346	2 157	2 027
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 928	21 891	25 077	26 731	27 844	28 506	27 962	28 047	28 242

ELECTRIC OPERATIONS (PUB_MH_II_45_2pct_CGAAP ASL without Salvage)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823	42 952
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 384)	(17 200)	(18 031)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 710	24 666	24 623	24 921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 389	2 539	2 792	3 092	3 317	3 873	3 734	4 400	5 082	5 831
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	659	650	639	627	621	621	624	634	648	661
	28 202	28 362	28 614	28 891	29 100	29 617	29 467	30 125	30 830	31 668
LIABILITIES AND EQUITY										
Long-Term Debt	23 795	24 398	24 601	24 743	24 676	24 149	24 139	24 143	24 137	23 781
Current and Other Liabilities	1 985	1 536	1 469	1 415	1 388	1 988	1 263	1 219	1 152	1 466
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	1 963	1 930	2 009	2 160	2 426	2 832	3 379	4 037	4 776	5 616
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	28 202	28 362	28 614	28 891	29 100	29 617	29 467	30 125	30 830	31 668

ELECTRIC OPERATIONS (PUB_MH_II_45_2pct_CGAAP ASL without Salvage)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 929	2 012	2 109	2 208	2 328	2 711	2 926	3 039	3 171
Cash Paid to Suppliers and Employees	(803)	(871)	(943)	(974)	(1 000)	(1 015)	(1 070)	(1 100)	(1 124)	(1 157)
Interest Paid	(511)	(514)	(547)	(593)	(786)	(935)	(1 233)	(1 356)	(1 341)	(1 354)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	558	544	573	456	412	439	499	588	676
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 990	1 600	1 390	800	560	580
Sinking Fund Withdrawals	110	21	-	8	448	205	295	718	165	28
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 213	1 471	734	774	243	286
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(242)	(246)	(264)	(358)	(254)	(261)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 517)	(1 831)	(1 303)	(1 144)	(982)	(988)
Net Increase (Decrease) in Cash	(270)	(106)	57	(78)	152	52	(131)	129	(151)	(26)
Cash at Beginning of Year	133	(137)	(243)	(186)	(264)	(112)	(60)	(191)	(62)	(214)
Cash at End of Year	(137)	(243)	(186)	(264)	(112)	(60)	(191)	(62)	(214)	(240)

ELECTRIC OPERATIONS (PUB_MH_II_45_2pct_CGAAP ASL without Salvage)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 290	3 339	3 476	3 581	3 713	3 866	4 004	4 089	4 171	4 274
Cash Paid to Suppliers and Employees	(1 181)	(1 191)	(1 213)	(1 227)	(1 249)	(1 270)	(1 290)	(1 315)	(1 336)	(1 364)
Interest Paid	(1 361)	(1 368)	(1 370)	(1 386)	(1 390)	(1 375)	(1 361)	(1 271)	(1 251)	(1 220)
Interest Received	20	22	35	49	63	72	84	64	79	94
	767	801	929	1 017	1 137	1 293	1 437	1 568	1 663	1 784
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	590	580	190	190	(20)	170	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	299	106	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	456	205	161	163	(45)	178	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(273)	(272)	(281)	(294)	(307)	(316)	(325)	(303)	(314)	(325)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 047)	(1 054)	(1 059)	(1 065)	(1 095)	(1 089)	(1 138)	(1 129)	(1 187)	(1 280)
Net Increase (Decrease) in Cash	176	(47)	31	115	(3)	382	258	380	429	458
Cash at Beginning of Year	(240)	(64)	(111)	(80)	35	32	414	672	1 052	1 481
Cash at End of Year	(64)	(111)	(80)	35	32	414	672	1 052	1 481	1 939

ELECTRIC OPERATIONS (PUB_MH_II_45_3pct_CGAAP ASL without Salvage)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 401	1 415	1 421	1 443	1 450	1 461	1 466	1 473	1 485	1 496
additional*	35	83	143	209	277	349	423	502	586	674
BPIII Reserve Account	(30)	(32)	(33)	(35)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 914	1 995	2 088	2 210	2 340	2 721	2 933	3 045	3 174
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	549	584	754	890	1 199	1 331	1 340	1 357
Depreciation and Amortization	405	372	395	419	492	495	581	638	713	735
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	135	144	145	145	152	151	162
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 795	1 930	2 021	2 292	2 445	2 895	3 128	3 224	3 295
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	131	72	74	(76)	(102)	(164)	(194)	(181)	(124)
* Additional General Consumers Revenue										
Percent Increase	2.75%	3.00%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%
Cumulative Percent Increase	2.75%	5.83%	10.09%	14.51%	19.11%	23.90%	28.88%	34.06%	39.45%	45.05%
Financial Ratios										
Equity	22%	18%	17%	15%	14%	14%	13%	11%	10%	10%
Interest Coverage	1.16	1.18	1.08	1.07	0.93	0.92	0.87	0.86	0.87	0.91
Capital Coverage	0.98	0.99	0.91	1.07	0.86	0.78	0.80	0.91	1.06	1.19

ELECTRIC OPERATIONS (PUB_MH_II_45_3pct_CGAAP ASL without Salvage)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	1 510	1 524	1 537	1 551	1 564	1 580	1 597	1 614	1 632	1 650
additional*	768	868	972	1 083	1 199	1 323	1 455	1 533	1 613	1 697
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3 290	3 336	3 471	3 572	3 701	3 849	3 982	4 067	4 148	4 251
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 359	1 357	1 346	1 347	1 334	1 313	1 277	1 211	1 175	1 131
Depreciation and Amortization	757	768	782	796	805	815	826	836	850	867
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	163	164	165	166	167	169	170	171	174	175
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3 344	3 364	3 389	3 420	3 437	3 448	3 441	3 412	3 412	3 414
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(59)	(29)	78	147	257	392	529	640	718	818
* Additional General Consumers Revenue										
Percent Increase	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	4.02%	2.00%	2.00%	2.00%
Cumulative Percent Increase	50.88%	56.94%	63.25%	69.81%	76.64%	83.73%	91.12%	94.94%	98.84%	102.82%
Financial Ratios										
Equity	10%	10%	10%	11%	12%	14%	16%	19%	22%	25%
Interest Coverage	0.96	0.98	1.06	1.11	1.19	1.29	1.41	1.52	1.60	1.70
Capital Coverage	1.24	1.29	1.46	1.56	1.68	1.92	2.02	2.18	2.27	2.40

ELECTRIC OPERATIONS (PUB_MH_II_45_3pct_CGAAP ASL without Salvage)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 296	2 599	2 728	2 167	2 239	2 443
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	340	403	468	541	595	640	666	673	673
	16 993	18 928	21 890	25 077	26 730	27 844	28 506	27 962	28 046	28 241
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 906	22 792	22 955	23 450	23 641
Current and Other Liabilities	2 016	2 165	2 126	3 114	2 275	2 731	2 699	2 215	1 956	2 047
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	114	150	161	107	54	-	-	-
Retained Earnings	2 717	2 827	2 899	2 973	2 897	2 794	2 630	2 436	2 256	2 131
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 928	21 890	25 077	26 730	27 844	28 506	27 962	28 046	28 241

ELECTRIC OPERATIONS (PUB_MH_II_45_3pct_CGAAP ASL without Salvage)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823	42 952
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 384)	(17 200)	(18 031)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 710	24 666	24 623	24 921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 388	2 538	2 790	3 054	3 415	3 753	3 596	4 243	4 904	5 630
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	659	650	639	627	621	621	624	634	648	661
	28 201	28 361	28 611	28 852	29 198	29 497	29 329	29 967	30 651	31 467
LIABILITIES AND EQUITY										
Long-Term Debt	23 595	24 198	24 401	24 543	24 676	23 949	23 939	23 943	23 937	23 581
Current and Other Liabilities	2 074	1 622	1 556	1 470	1 389	1 986	1 261	1 217	1 150	1 464
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2 073	2 043	2 120	2 267	2 523	2 914	3 443	4 082	4 799	5 617
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	28 201	28 361	28 611	28 852	29 198	29 497	29 329	29 967	30 651	31 467

ELECTRIC OPERATIONS (PUB_MH_II_45_3pct_CGAAP ASL without Salvage)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 944	2 026	2 121	2 218	2 337	2 718	2 931	3 042	3 171
Cash Paid to Suppliers and Employees	(803)	(871)	(943)	(974)	(1 000)	(1 016)	(1 070)	(1 100)	(1 125)	(1 157)
Interest Paid	(511)	(514)	(547)	(593)	(785)	(930)	(1 221)	(1 355)	(1 336)	(1 348)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	573	557	585	468	426	458	505	597	682
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 600	1 590	600	760	580
Sinking Fund Withdrawals	110	21	-	8	448	205	294	717	165	27
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 470	933	574	443	285
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(246)	(263)	(358)	(253)	(260)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 516)	(1 831)	(1 303)	(1 144)	(981)	(987)
Net Increase (Decrease) in Cash	(270)	(92)	70	(66)	(35)	66	88	(66)	58	(19)
Cash at Beginning of Year	133	(137)	(229)	(158)	(224)	(259)	(193)	(105)	(171)	(113)
Cash at End of Year	(137)	(229)	(158)	(224)	(259)	(193)	(105)	(171)	(113)	(132)

ELECTRIC OPERATIONS (PUB_MH_II_45_3pct_CGAAP ASL without Salvage)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 288	3 333	3 468	3 569	3 698	3 846	3 979	4 064	4 144	4 247
Cash Paid to Suppliers and Employees	(1 181)	(1 191)	(1 213)	(1 227)	(1 249)	(1 270)	(1 290)	(1 315)	(1 336)	(1 364)
Interest Paid	(1 358)	(1 360)	(1 363)	(1 378)	(1 380)	(1 373)	(1 354)	(1 264)	(1 245)	(1 215)
Interest Received	20	22	35	49	62	72	84	64	78	93
	768	804	928	1 013	1 131	1 274	1 419	1 548	1 642	1 761
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	390	580	190	190	180	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	298	105	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	255	204	161	163	155	(22)	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(272)	(271)	(280)	(293)	(305)	(316)	(323)	(301)	(312)	(323)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 046)	(1 053)	(1 058)	(1 064)	(1 094)	(1 089)	(1 136)	(1 127)	(1 184)	(1 277)
Net Increase (Decrease) in Cash	(23)	(45)	31	112	192	163	242	363	411	438
Cash at Beginning of Year	(132)	(155)	(200)	(168)	(57)	136	299	541	904	1 315
Cash at End of Year	(155)	(200)	(168)	(57)	136	299	541	904	1 315	1 753

Section:	Tab 4: Figure 4.3 and 4.4	Page No.:	
Topic:	Capital Expenditure Forecast		
Subtopic:			
Issue:	Change in Capital Expenditure Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please file the respective Figures 4.3, 4.4 and 4.6 indicating the 20-year change reflected in CEF 14.

RATIONALE FOR QUESTION:

To reconcile the change in the Capital Expenditure Forecast over the 20-year time horizon of IFF14.

RESPONSE:

Please see the following tables for Figures 4.3, 4.4 and 4.6 indicating 20-year changes reflected in CEF14.

Figure 4.3

Electric Only	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
CEF13	**2 013**	**2 422**	**2 496**	**2 326**	**2 030**	**1 845**	**1 337**	**1 719**	**2 281**	**2 322**	**20 792**
Incr (Decr)	9	69	577	799	48	(414)	(339)	(968)	(1 601)	(1 641)	(3 460)
CEF14	**2 023**	**2 491**	**3 073**	**3 125**	**2 078**	**1 432**	**999**	**751**	**679**	**681**	**17 332**

Figure 4.3

Electric Only	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
CEF13	**2 119**	**2 005**	**1 795**	**1 355**	**1 052**	**879**	**780**	**631**	**580**	**628**	**32 615**
Incr (Decr)	(1 390)	(1 270)	(1 060)	(625)	(307)	(153)	(10)	151	242	282	(7 599)
CEF14	**729**	**735**	**735**	**730**	**745**	**726**	**770**	**782**	**822**	**910**	**25 016**

Figure 4.4

CEF14

	Total Projected Cost	20 Year Increase (Decrease)
	($ Millions)	
Conawapa - Generation	397	(10 065)
Bipole III - Transmission Line	1 655	407
Bipole III - Converter Stations	2 675	881
Bipole III - Collector Lines	260	71
Keeyask - Generation	6 496	349
Demand Side Management	NA	802
Base Capital Target	NA	1 957
Additional North South Trasmission	-	(475)
Gillam Redevelopment and Expansion Program	266	(100)
Dorsey 230kV Zone Building	-	(63)
Pointe du Bois Powerhouse Rebuild	1 852	(1 471)
New Adelaide Station - 66/12kV	62	62
Other System Upgrades		46
		(7 599)

Figure 4.6
Major New Generation and Transmission Capital Expenditure Forecast CEF14

(in millions of $)	2014/15	2015/16	2016/17	Cumulative to 2033/34*	20 Year Increase (Decrease)
Wuskwatim - Generation	41	13	15	68	32
Keeyask - Generation	776	676	962	5 579	349
Grand Rapids Hatchery Upgrade & Expansion	2	5	9	23	23
Conawapa - Generation	43	31	21	96	(10 065)
Kelsey Improvements & Upgrades	14	9	13	37	35
Kettle Improvements & Upgrades	7	24	25	138	27
Pointe du Bois Spillway Replacement	114	52	4	170	39
Pointe du Bois - Transmission	16	17	14	51	1
Pointe du Bois Powerhouse Rebuild	-	-	-	68	(1 471)
Gillam Redevelopment and Expansion Program (GREP)	20	22	23	266	(100)
Bipole III - Transmission Line	203	360	381	1 514	407
Bipole III - Converter Stations	221	581	829	2 356	881
Bipole III - Collector Lines	58	76	52	227	71
Bipole III - Community Development Initiative	2	2	2	8	1
Riel 230/ 500 kV Station	36	6	-	42	1
Manitoba-Minnesota Transmission Project	7	33	100	348	(1)
Demand Side Management	52	59	77	1 187	802
Target Adjustment	(161)	(51)	(61)	(19)	(128)
Other	-	-	-	453	(495)
Total	**1 452**	**1 914**	**2 463**	**12 611**	**(9 591)**

* Excludes capital expenditures prior to 2013/14

Section:	Tab 2	**Page No.:**	Appendix 11.9, MFR 3
Topic:	Overview and Reasons for Application		
Subtopic:	Rate Increases		
Issue:	Detail of Rate Increases		

PREAMBLE TO IR (IF ANY):

Year	% Rate Increase Requested	% Approved Final/Interim	MB CPI	Annual Increase in Revenue	Cumulative % Increase	Cumulative MB CPI	Cumulative Additional Revenue From Rate Increases	% of Total Revenue from Domestic (Actual)	Actual Consolidated Debt to Equity Ratio
2003/04	0.0%	-0.72% April 1/03	0.90%	$ (6.5)	-0.72%	0.90%	$ (6.5)	72%	87:13
2004/05	3% April 1/04	5% August 1/04	2.70%	32.3	4.24%	3.62%	25.8	63%	85:15
2005/06	2.5% April 1/05	2.25% April 1/05	2.40%	21.8	6.59%	6.11%	47.6	54%	81:19
2006/07	2.25% February 1/07	2.25% March 1/07	2.00%	23.1	8.99%	8.23%	70.7	63%	80:20
2007/08	0.0% April 1/07	0.0% April 1/07	1.90%	-	8.99%	10.29%	70.7	63%	73:27
2008/09	2.9% April 1/08	5% July 1/08	2.20%	52.4	14.44%	12.72%	123.1	64%	77:23
2009/10	3.9% April 1/09	2.84% April 1/09	0.60%	32.8	17.69%	13.39%	155.9	72%	73:27
2010/11	2.9% April 1/10	2.8% interim April 1/10	1.00%	32.9	20.98%	14.53%	188.8	74%	73:27
2011/12	2.9% April 1/11	2.0% April 1/11	2.80%	24.4	23.40%	17.73%	213.2	76%	74:26
2012/13	3.5% April 1/12	2% interim April 1/12	2.00%	25.8	25.87%	20.09%	239.0	79%	76:24
2012/13	2.5% Sept 1/12	2.4% interim Sept 1/12	2.00%	31.0	28.89%	22.49%	270.0	79%	76:24
2013/14*	3.5% April 1/13	n/a	2.00%	47.4	33.40%	24.94%	317.4	79%	82:18

* To calculate the annual increase in revenue and the cumulative % rate increase, approval of a 3.5% rate increase effective April 1, 2013 has been assumed.

Please note that the proposed rate increases for 2014/15 and 2015/16 are indicative only and are subject to review and approval of the MHEB.

QUESTION:

Please file an update to Appendix 11.9 on the same basis that was provided at the 2012 GRA. Please see attached.

RATIONALE FOR QUESTION:

To illustrate MH’s rate increases since 2003/04.

RESPONSE:

Please see the updated table on the following page.

Year	% Rate Increase Requested	% Approved Final/Interim	MB CPI	Annual Increase in Revenue ($millions)	Cumulative % Increase	Cumulative MB CPI	Cumulative Additional Revenue from Rate Increases	% of Total Revenue from Domestic (Actual)	Actual Consolidated Debt to Equity Ratio
1999/00	0%	-	2.2%	$0.0	0.00%	2.20%	$0.0	66%	83:17
2000/01	0%	-	2.5%	$0.0	0.00%	4.76%	$0.0	62%	80:20
2001/02	-1.92% Nov 1/01	-	2.1%	-$14.4	-1.92%	6.95%	-$14.4	57%	77:23
2002/03	0%	-	2.3%	$0.0	-1.92%	9.41%	-$14.4	65%	80:20
2003/04	0% Apr 1/03	-0.72% Apr 1/03	0.9%	-$6.5	-2.63%	10.40%	-$20.9	72%	87:13
2004/05	3% Apr 1/04	5% Aug 1/04	2.7%	$32.3	2.24%	13.38%	$11.4	63%	85:15
2005/06	2.5% Apr 1/05	2.25% Apr 1/05	2.4%	$21.8	4.54%	16.10%	$33.2	54%	81:19
2006/07	2.25% Feb 1/07	2.25% Mar 1/07	2.0%	$23.1	6.90%	18.42%	$56.3	63%	80:20
2007/08	0% Apr 1/07	-	1.9%	$0.0	6.90%	20.67%	$56.3	63%	73:27
2008/09	2.9% Apr 1/08	5.0% Jul 1/08	2.2%	$52.4	12.24%	23.33%	$108.7	64%	77:23
2009/10	3.9% Apr 1/09	2.84% Apr 1/09	0.6%	$32.8	15.43%	24.07%	$141.5	73%	73:27
2010/11	2.9% Apr 1/10	2.8% Apr 1/10	1.0%	$32.9	18.66%	25.31%	$174.4	75%	73:27
2011/12	2.9% Apr 1/11	2.0% Apr 1/11	2.8%	$24.4	21.03%	28.82%	$198.8	77%	74:26
2012/13	3.5% Apr 1/12	2.0% Apr 1/12	1.6%	$25.8	23.45%	30.88%	$224.6	79%	75:25
2012/13	2.5% Sep 1/12	2.4% Sep 1/12	1.6%	$31.0	26.42%	30.88%	$255.6	79%	75:25
2013/14	3.5% Apr 1/13	3.5% May 1/13	2.4%	$47.6	30.84%	34.02%	$303.2	76%	76:24
2014/15	3.95% Apr 1/14	2.75% May 1/14	1.8%**	$38.7	34.44%	36.43%	$341.9	78%	77:23
2015/16*	3.95% Apr 1/15 (proposed)	n/a	1.9%**	$57.4	39.75%	39.02%	$399.3	78%	81:19
2016/17*	3.95% Apr 1/16 (proposed)	n/a	2%**	$59.9	45.27%	41.80%	$459.2	78%	83:17

*Calculations assume that the proposed rate increases for fiscal years 2016 and 2017 are approved.
** Forecast

Section:	Chapter 2: Figure 2.19 and 2.20 , 2.21	**Page No.:**	
Topic:	Overview and Reasons for Application		
Subtopic:	Rate Increases		
Issue:	Alternative Rate Scenarios		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please refile Figures 2.19, 2.20, 2.21, 2.25 and 2.30 to include the plots for the following scenarios (For Figure 2.25, the analysis should include the 2014/15 interim increase on the proposed rate increase line):

   i. A 5% rate increase in 2015/16 and 3.95% rate increases in each year through 2034
   ii. A 5% increase in rates in 2015/16 and 2016/17 followed by 3.95 rate increases in each subsequent year.

b) Please also refile Appendix 11.12 to reflect the above two scenarios.

RATIONALE FOR QUESTION:

To assess the impact of alternative rate increases.

RESPONSE:

Please see the attached figures.

a)

Figure 2.19: Projected Net Income (2015-2024)

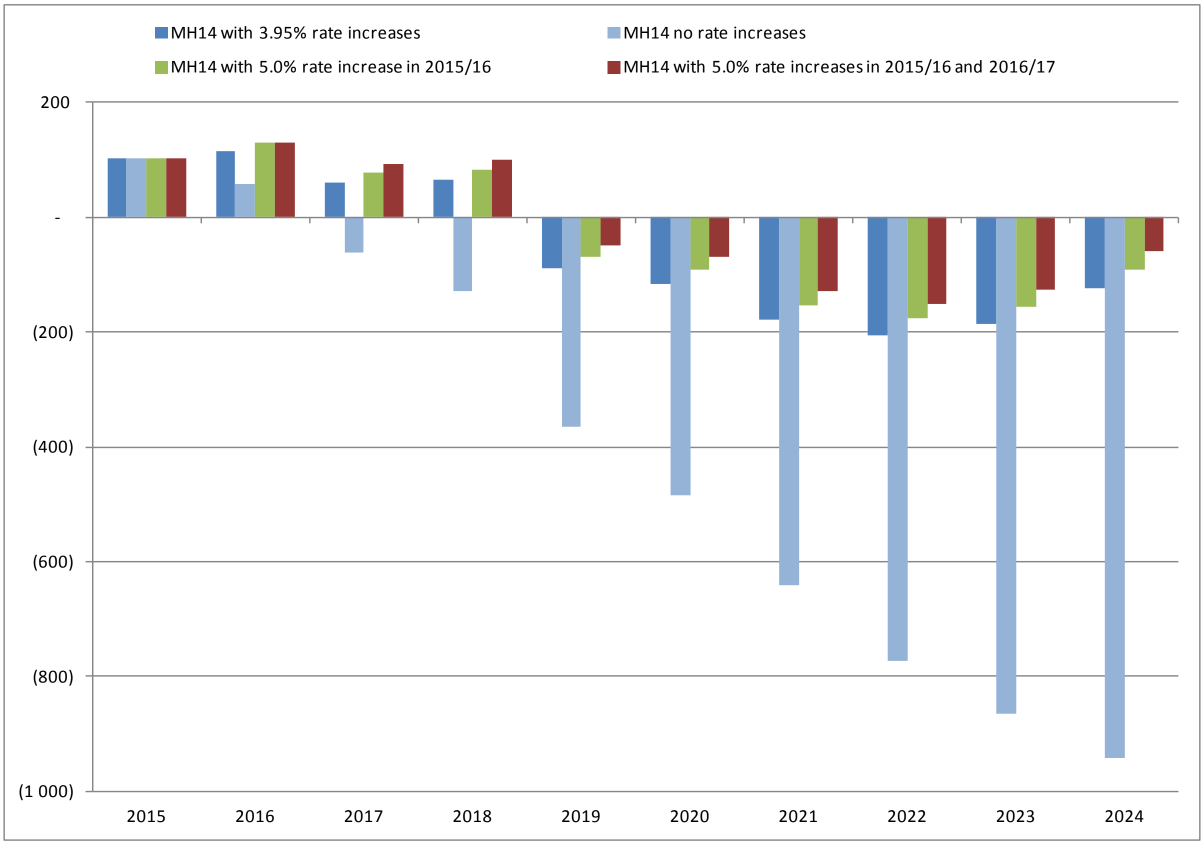


Figure 2.20: Projected Retained Earnings (2015-2024)

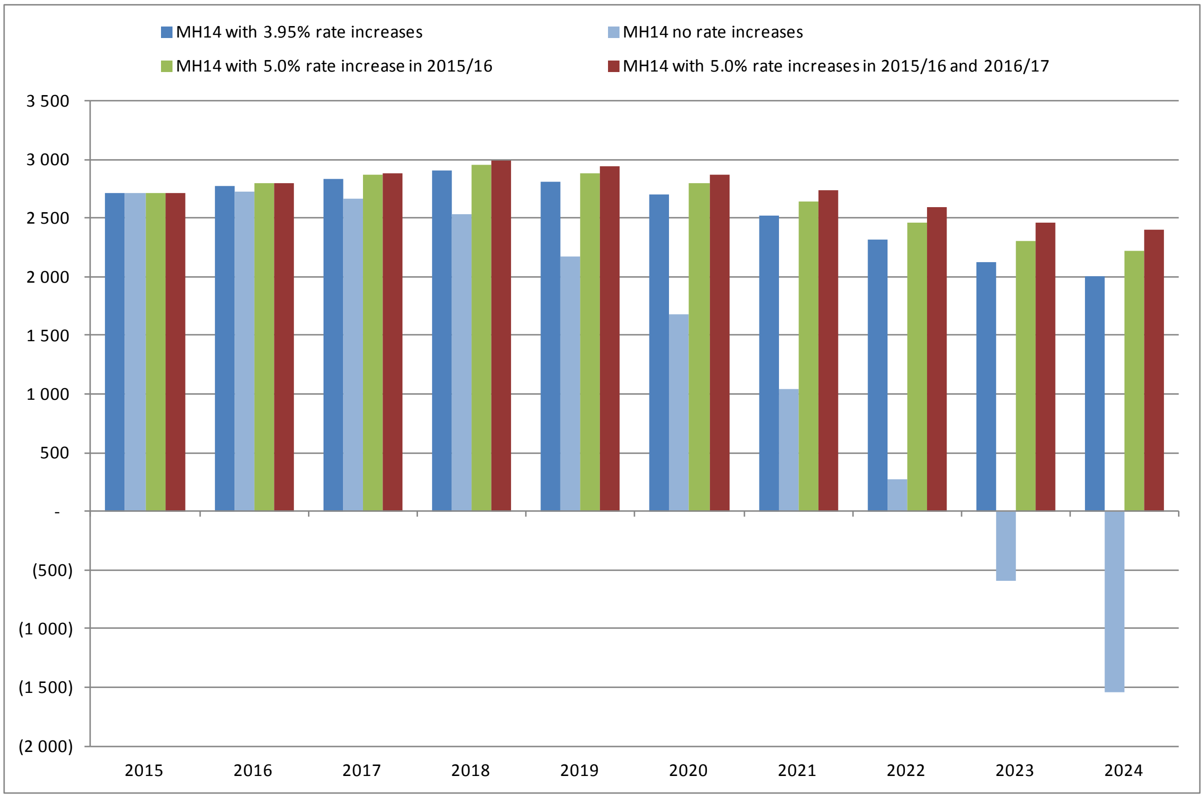


Figure 2.21: Projected Equity Ratio (2015-2024)

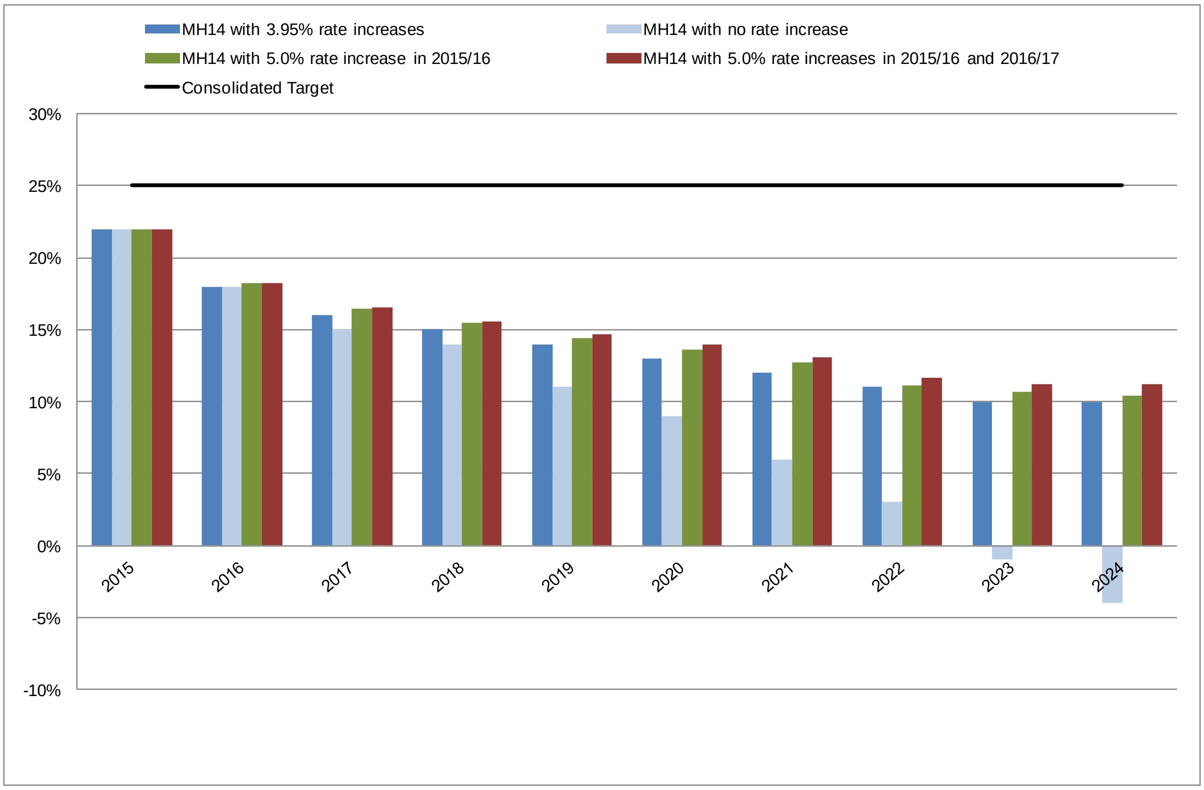


Figure 2.25: Net Income from Electric Operations – Part (a) (i)

Net Income - Electricity Operations

(in millions of $)	2013	2014	Forecast 2015	2016	2017
Revenue					
General Consumers Revenue					
- at approved rates	$ 1 341	$ 1 424	$ 1 401	$ 1 415	$ 1 421
- Bipole III Reserve	-	(19)	(30)	(33)	(34)
Extraprovincial Revenue (net of Fuel & Power Purchased and Water Rentals)	101	137	150	181	147
Other Revenue	30	22	15	14	14
	1 472	1 564	1 537	1 578	1 548
Expenses	1 407	1 439	1 495	1 570	1 651
Operating, Maintenance and Administrative	463	481	486	542	552
Finance Expense	452	435	495	510	546
Depreciation and Amortization	392	411	405	401	422
Capital and Other Taxes	86	97	99	107	121
Corporate Allocation	9	9	9	8	8
Other expenses	5	6	2	2	2
Non-controlling Interest	13	22	25	12	8
Net Income (loss) before proposed rate increases	$ 78	$ 147	$ 67	$ 19	$ (96)
Proposed rate increases (2.75% May 1, 2014, 5.00% April 1, 2015, and 3.95% April 1, 2016)			35	112	173
Net Income including proposed rate increases	$ 78	$ 147	$ 102	$ 131	$ 77

Retained Earnings and Financial Ratios (without proposed rate increases)

	2013	2014	2015	2016	2017
Retained Earnings (electric operations)	$ 2 468	$ 2 615	$ 2 681	$ 2 646	$ 2 549
Debt to Equity Ratio (electric operations)	75:25	77:23	78:22	83:17	85:15
Interest Coverage Ratio (electric operations)	1.13	1.25	1.11	1.03	0.88
Capital Coverage Ratio (electric operations)	1.26	1.39	0.92	0.84	0.66

Retained Earnings and Financial Ratios (including proposed rate increases)

	2013	2014	2015	2016	2017
Retained Earnings (electric operations)	$ 2 468	$ 2 615	$ 2 717	$ 2 794	$ 2 870
Debt to Equity Ratio (electric operations)	75:25	77:23	78:22	82:18	84:16
Interest Coverage Ratio (electric operations)	1.13	1.25	1.16	1.18	1.09
Capital Coverage Ratio (electric operations)	1.26	1.39	0.98	1.04	0.97

Figure 2.25: Net Income from Electric Operations – Part (a) (ii)

Net Income - Electricity Operations

(in millions of $)	2013	2014	Forecast 2015	2016	2017
Revenue					
General Consumers Revenue					
- at approved rates	$ 1 341	$ 1 424	$ 1 401	$ 1 415	$ 1 421
- Bipole III Reserve	-	(19)	(30)	(33)	(34)
Extraprovincial Revenue (net of Fuel & Power Purchased and Water Rentals)	101	137	150	181	147
Other Revenue	30	22	15	14	14
	1 472	1 564	1 537	1 578	1 547
Expenses	1 407	1 439	1 495	1 570	1 651
Operating, Maintenance and Administrative	463	481	486	542	552
Finance Expense	452	435	495	510	546
Depreciation and Amortization	392	411	405	401	422
Capital and Other Taxes	86	97	99	107	121
Corporate Allocation	9	9	9	8	8
Other expenses	5	6	2	2	2
Non-controlling Interest	13	22	25	12	8
Net Income (loss) before proposed rate increases	$ 78	$ 147	$ 67	$ 19	$ (96)
Proposed rate increases (2.75% May 1, 2014, 5.00% April 1, 2015, and 5.00% April 1, 2016)			35	112	189
Net Income including proposed rate increases	$ 78	$ 147	$ 102	$ 131	$ 93

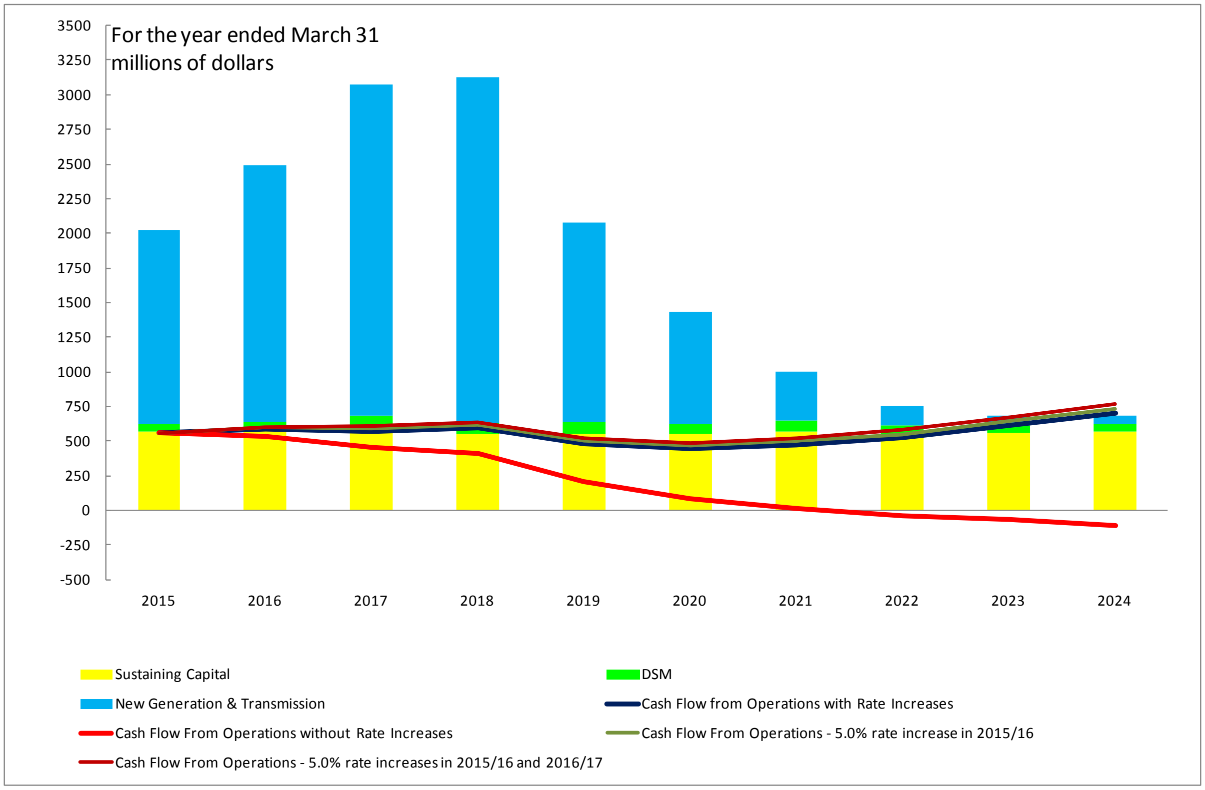
Retained Earnings and Financial Ratios (without proposed rate increases)

	2013	2014	2015	2016	2017
Retained Earnings (electric operations)	$ 2 468	$ 2 615	$ 2 681	$ 2 646	$ 2 549
Debt to Equity Ratio (electric operations)	75:25	77:23	78:22	83:17	85:15
Interest Coverage Ratio (electric operations)	1.13	1.25	1.11	1.03	0.88
Capital Coverage Ratio (electric operations)	1.26	1.39	0.92	0.84	0.66

Retained Earnings and Financial Ratios (including proposed rate increases)

	2013	2014	2015	2016	2017
Retained Earnings (electric operations)	$ 2 468	$ 2 615	$ 2 717	$ 2 794	$ 2 886
Debt to Equity Ratio (electric operations)	75:25	77:23	78:22	82:18	83:17
Interest Coverage Ratio (electric operations)	1.13	1.25	1.16	1.18	1.11
Capital Coverage Ratio (electric operations)	1.26	1.39	0.98	1.04	1.00

Figure 2.30: Electricity Capital Expenditures and Cash Flow from Operations Including and Excluding Proposed and Indicative Rate Increases



b) i. A 5% rate increase in 2015/16 and 3.95% rate increases in each year through 2034

Appendix 11.12 - Detailed debt to equity ratio, capital coverage ratio and interest coverage ratio, net assets, net income, total debt and retained earnings

Fiscal Year Ended	Debt/ Equity Ratio	Capital Coverage Ratio	Interest Coverage Ratio	Total Assets	Net Income	Total Debt	Retained Earnings
2015	78:22	0.98	1.16	16 993	102	11 854	2 717
2016	82:18	1.04	1.18	18 866	131	14 031	2 794
2017	84:16	0.97	1.09	21 800	77	16 786	2 870
2018	85:15	1.12	1.08	24 961	83	19 695	2 953
2019	86:14	0.91	0.94	26 585	(68)	21 296	2 885
2020	86:14	0.85	0.92	27 668	(92)	22 455	2 793
2021	87:13	0.87	0.88	28 298	(153)	23 068	2 640
2022	89:11	0.99	0.87	27 727	(177)	22 977	2 464
2023	89:11	1.14	0.88	27 786	(156)	23 192	2 308
2024	90:10	1.28	0.93	27 963	(90)	23 452	2 218
2025	89:11	1.32	0.99	27 912	(16)	23 413	2 202
2026	89:11	1.38	1.01	28 060	16	23 534	2 218
2027	89:11	1.55	1.10	28 296	129	23 630	2 346
2028	88:12	1.66	1.15	28 664	202	23 783	2 548
2029	86:14	1.77	1.24	28 922	316	23 706	2 863
2030	84:16	2.02	1.35	29 285	456	23 609	3 318
2031	82:18	2.12	1.47	29 183	595	22 892	3 913
2032	79:21	2.37	1.65	29 952	771	22 863	4 683
2033	75:25	2.56	1.80	30 840	922	22 827	5 604
2034	70:30	2.79	2.00	31 940	1 103	22 821	6 707

b) ii. A 5% increase in rates in 2015/16 and 2016/17 followed by 3.95 rate increases in each subsequent year.

Appendix 11.12 - Detailed debt to equity ratio, capital coverage ratio and interest coverage ratio, net assets, net income, total debt and retained earnings

Fiscal Year Ended	Debt/ Equity Ratio	Capital Coverage Ratio	Interest Coverage Ratio	Total Assets	Net Income	Total Debt	Retained Earnings
2015	78:22	0.98	1.16	16 993	102	11 854	2 717
2016	82:18	1.04	1.18	18 866	131	14 031	2 794
2017	83:17	1.00	1.11	21 800	93	16 770	2 886
2018	84:16	1.16	1.10	24 961	101	19 661	2 987
2019	85:15	0.95	0.96	26 585	(48)	21 239	2 939
2020	86:14	0.88	0.94	27 667	(69)	22 378	2 869
2021	87:13	0.91	0.90	28 298	(128)	22 973	2 742
2022	88:12	1.05	0.89	27 727	(151)	22 853	2 591
2023	89:11	1.20	0.90	27 785	(127)	23 038	2 463
2024	89:11	1.34	0.96	27 962	(59)	23 267	2 404
2025	89:11	1.38	1.01	27 910	19	23 192	2 424
2026	88:12	1.44	1.04	28 058	54	23 275	2 477
2027	87:13	1.61	1.13	28 354	170	23 391	2 646
2028	86:14	1.72	1.19	28 603	247	23 383	2 893
2029	85:15	1.84	1.28	28 911	367	23 306	3 259
2030	82:18	2.10	1.40	29 327	509	23 209	3 768
2031	80:20	2.20	1.53	29 283	652	22 492	4 419
2032	76:24	2.46	1.72	30 113	832	22 463	5 250
2033	72:28	2.65	1.88	31 066	987	22 427	6 237
2034	68:32	2.89	2.09	32 236	1 172	22 421	7 409

Section:	Tab 5: Section5.14	Page No.:	PUB/MH I-70b/ Appendix11.23
Topic:	Financial Results and Forecast		
Subtopic:	OM&A Expenditures		
Issue:	Cost Containment Initiatives		

PREAMBLE TO IR (IF ANY):

The total straight time EFTs in 2013/14 is 6,375 and is forecast to grow to 6,381 in 2016/17, an increase of 7 positions. MH has provided a schedule in PUB/MH I-70b that shows a commitment to reduce EFT by business units by 331 over the three-year period. Overtime EFTs grow by 51 EFT over the same three-year period. It is not clear on how the committed savings are reflected in the forecast staffing levels.

QUESTION:

Please update the response to PUB/MH I-70(b) to include actual 2013/14 total staffing per Appendix 11.23 and provide a continuity schedule of the proposed changes in staffing levels by business unit in each of the years through 2016/17 to reconcile with the reported EFTs in PUB/MH I-70b.

RATIONALE FOR QUESTION:

To explore cost containment through staffing levels.

RESPONSE:

As outlined in the response to PUB/MH-I-70b, Manitoba Hydro has committed to reduce 331 operational positions or equivalent cost reductions over the three-year period from 2014/15 to 2016/17. The timing of the position reductions will be realized throughout each year and therefore, will not equate to a full EFT until the position has been removed for a full year. As a result, the full EFT reduction and associated cumulative savings will not be fully realized until 2017/18.

As shown in the table below, a reduction of 292 EFTs (159 +133) in Operations & Maintenance and Governance, Support & Services EFTs is projected from 2013/14 to 2016/17. The costs associated with Capital Construction EFTs are reflected in the asset base and not in the revenue requirement until the asset is in-service.

MANITOBA HYDRO
STRAIGHT TIME EQUIVALENT FULL TIME (EFT) EMPLOYEES

	2013/14 Actual	2016/17 Forecast	Change Inc/(Dec)
Capital Construction	2,058	2,357	299
Operations & Maintenance	2,734	2,575	(159)
Governance, Support & Services	1,582	1,449	(133)
Total Corporation	6,374	6,381	7

Manitoba Hydro is unable to provide a continuity schedule between PUB/MH-I-70b and Appendix 11.23 as EFTs and positions are not comparable.

Section:	Tab 5: Appendix 5.5	Page No.:	Appendix 11.26
Topic:	Financial Results & Forecasts		
Subtopic:	EFT Metrics		
Issue:	Changes in EFT's		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please update Appendix 11.26 to include EFTs per 10,000 domestic customers.

b) Please file an updated metric analysis of Appendix 11.26 based on (a) including total EFTs (ST & OT).

c) Please file an updated metric analysis based on (b) excluding employees allocated to construction. For 2007/08 to 2011/12, use the EFT's allocated to Capital (ST & OT) presented at the 2012 GRA.

RATIONALE FOR QUESTION:

To assess EFT levels.

RESPONSE:

Please see the following table for the EFT information requested in parts a, b and c. Please note that the capital EFT information for 2012/13 to 2016/17 is not comparable to the capital EFT information for prior years as the methodology for calculating capital EFTs has changed and cannot be restated. The calculation of the capital EFTs for the years 2007/08 through 2011/12 includes an estimate of the Governance, Support and Services EFTs that were capitalized through overheads.

Data Table										
	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
EFTs (ST & OT)	6 071	6 276	6 429	6 594	6 608	6 678	6 756	6 864	6 902	6 814
EFTs (ST)	5 747	5 935	6 080	6 246	6 250	6 296	6 374	6 475	6 468	6 381
Capital EFTs (ST & OT)*	2 369	2 397	2 479	2 566	2 678	2 081	2 204	2 362	2 568	2 580
Governance Support and Service EFTs (ST & OT)	-	-	-	-	-	1 651	1 644	1 647	1 569	1 501
Operating EFTs (ST & OT)*	3 702	3 879	3 950	4 028	3 930	2 946	2 908	2 855	2 765	2 733
GWh of domestic Supply	23 985	24 285	23 295	23 783	23 499	24 642	25 510	25 178	25 610	25 766
GWh of total Supply	35 354	34 528	33 961	34 102	33 235	33 230	35 392	35 217	34 538	31 443
Electric Customers	521 599	527 472	532 359	537 299	542 681	548 774	555 760	561 825	568 443	575 648
Domestic revenue (in millions)	1 075	1 127	1 145	1 200	1 193	1 341	1 405	1 407	1 479	1 544

*2007/08 to 2011/12 EFTs include a portion of Governance Support and Services EFTs.

Part a

Information Requested - Straight Time										
	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
EFTs - ST	5 747	5 935	6 080	6 246	6 250	6 296	6 374	6 475	6 468	6 381
EFT per 1000 GWh of domestic supply	239.62	244.41	260.99	262.63	265.95	255.50	249.86	257.17	252.56	247.65
EFT per 1000 GWh of total supply	162.56	171.90	179.02	183.16	188.04	189.47	180.10	183.86	187.27	202.94
EFT per 10,000 domestic customers	110.19	112.53	114.20	116.25	115.16	114.73	114.69	115.25	113.78	110.85
EFT per $ millions of domestic revenue	5.35	5.27	5.31	5.20	5.24	4.69	4.54	4.60	4.37	4.13

Part b

Information Requested - Straight Time & Overtime										
	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
EFTs - ST & OT	6 071	6 276	6 429	6 594	6 608	6 678	6 756	6 864	6 902	6 814
EFT per 1000 GWh of domestic supply	253.12	258.43	275.98	277.26	281.20	271.00	264.84	272.62	269.50	264.46
EFT per 1000 GWh of total supply	171.72	181.77	189.31	193.36	198.83	200.96	190.89	194.91	199.84	216.71
EFT per 10,000 domestic customers	116.39	118.98	120.76	122.72	121.77	121.69	121.56	122.17	121.42	118.37
EFT per $ millions of domestic revenue	5.65	5.57	5.62	5.49	5.54	4.98	4.81	4.88	4.67	4.41

Part c

Information Requested - Operational & Governance, Support and Service EFTs (Straight Time & Overtime)										
	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
EFTs - ST & OT**	3 702	3 879	3 950	4 028	3 930	4 597	4 552	4 502	4 334	4 234
EFT per 1000 GWh of domestic supply	154.34	159.73	169.55	169.38	167.24	186.55	178.44	178.81	169.23	164.33
EFT per 1000 GWh of total supply	104.71	112.35	116.30	118.13	118.25	138.34	82.17	81.07	80.06	86.92
EFT per 10,000 domestic customers	70.97	73.54	74.19	74.98	72.42	83.77	52.32	50.82	48.64	47.48
EFT per $ millions of domestic revenue	3.44	3.44	3.45	3.36	3.29	3.43	2.07	2.03	1.87	1.77

** ‘EFTs - ST & OT’ for 2012/13 to 2016/17 includes Operating EFTs (ST & OT) & Governance Support and Services EFTs (ST & OT). This is not comparable to the 2007/08 to 2012/13 ‘EFTs (ST & OT)’ as only a portion of the Governance Support and Services EFTs is included in the 'Operating EFTs (ST & OT)' with the balance included in the 'Capital EFTs (ST & OT)'.

Section:	Tab 5 Appendix 5.5	Page No.:	Appendix 11.24 PUB/MH I-38 (d) & (e) 2012 GRA
Topic:	OM&A Expense		
Subtopic:	Salary & Wages		
Issue:	Salary Wages and Benefits Capitalized		

PREAMBLE TO IR (IF ANY):

At the last GRA MH stated Appendix 11.24 appears to not reconcile with PUB/MH I-16 2014/15 Interim. From a review of PUB/MH I-38 (d) & (e) 2012 GRA Appendix 11.24 appears to be prepared on a different basis, which excludes capitalized overhead.

QUESTION:

a) Please provide an update to PUB/MH I-16e from the 2014/15 Interim application, including a schedule which indicates the salary, wages and benefits as a percentage of OM&A, percentage of domestic revenue, and salary wages and benefits capitalized and the percentage of wages and salaries capitalized for each of the years 2004/05 to 2015/16.

b) Please provide a schedule which indicates the total salary, wages and benefits as a percentage of OM&A, percentage of domestic revenue, and salary wages and benefits capitalized.

c) Please provide the breakdown of capitalized labour and benefits in (b) by Capital Order Activity and Capitalized Overhead similar to PUB/MH I-38 d (2012 GRA).

d) Please provide the total Labour & Benefits Costs and the dollar and percentage of Labour & Benefits Capitalized in (c) for each of the years 2003/04 to 2016/17. Include the EFT equivalent in each year of Labour & Benefits capitalized similar to PUB/MH I-38 d (2012 GRA).

e) Provide a schedule that indicates the total increase in salary wages, benefits and overhead [both OM&A and Capitalized] related to an increase in EFT's for each of the years 2004/05 to 2015/16.

RATIONALE FOR QUESTION:

To review capitalized labour and benefits.

RESPONSE:

a) Please refer to Appendix 11.24 Operating Expenses MFR 4 parts i&ii) which provide a schedule of the wages & salaries, overtime and benefits charged to operations as a percentage of OM&A, and as a percentage of domestic revenue for 2003/04 to 2016/17.

Please refer to part iii) in the same Appendix for capitalized wages & salaries, overtime & employee benefits as a percentage of total wages & salaries, overtime & employee benefits for the same period.

b) The table below provides a schedule of the total wages & salaries, overtime and benefits as a percentage of OM&A, and as a percentage of domestic revenue for 2003/04 to 2016/17.

As indicated in part a) of this response, please refer to Appendix 11.24, Operating Expenses MFR 4, part iii) for capitalized wages & salaries, overtime & employee benefits for the same period. Please note that for the years 2003/04 to 2011/12, the estimated capitalized wages, salaries, overtime and benefits is based upon a high level calculation used in PUB/MH-I-5(c) from the 2010 GRA.

MANITOBA HYDRO
WAGES & SALARIES, OVERTIME & EMPLOYEE BENEFITS SCHEDULE
(in thousands of $)

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Total Wages & Salaries, Overtime, Employee Benefits	$398,449	$423,093	$440,473	$457,233	$477,838	$509,592	$541,307	$571,238	$611,356	$658,082	$699,970	$724,993	$751,523	$766,109
Total Costs (before capitalization)	$542,660	$569,749	$596,229	$615,849	$638,594	$687,149	$722,951	$748,471	$787,156	$841,225	$887,987	$924,766	$949,991	$967,104
Wages & Salaries, Overtime, Employee Benefits as a percentage of Total Costs	73%	74%	74%	74%	75%	74%	75%	76%	78%	78%	79%	78%	79%	79%
Domestic Revenue (GCR)	$918,231	$938,954	$983,653	$1,023,613	$1,074,581	$1,126,812	$1,144,891	$1,200,381	$1,192,797	$1,341,011	$1,405,301	$1,406,745	$1,479,405	$1,544,112
Wages & Salaries, Overtime, Employee Benefits as a percentage of Domestic	43%	45%	45%	45%	44%	45%	47%	48%	51%	49%	50%	52%	51%	50%

c) Please refer to Appendix 11.24 Operating Expenses MFR 4 part iii) for labour and benefits capitalized through activity rates. As discussed in Manitoba Hydro's response to PUB/MH-II-18, changes were made in 2012/13 such that the estimated amount of labour and expense capitalized does not include an estimation of the amount of Governance, Support and Services staff capitalized through overhead. As such, Manitoba Hydro cannot provide a breakdown of labour and benefits capitalized through overhead.

d) Please see Appendix 11.24 Operating Expenses MFR 4 part iii) which provides the total labour and benefit costs and the dollar and percentage of labour and benefits capitalized for the years 2003/04 to 2016/17.

Please see Appendix 5.5, Figures 5.5.8 and 5.5.10 for Capital Construction EFTs for the years 2012/13 to 2016/17. Manitoba Hydro implemented system changes in 2012/13 to align Manitoba Hydro's capitalization practices with industry standards to support the transition to IFRS. As a result of these changes, Capital Construction EFT information cannot be provided prior to 2012/13.

e) The following table reflects Business Unit wages & salaries, overtime and benefits related to EFTs from 2004/05 to 2016/17:

Fiscal Year	Wages & Salaries	Overtime	Benefits	Total	EFTs
2004/05	$ 319,353	$ 33,822	$ 76,628	$ 429,804	5,870
2005/06	$ 330,834	$ 37,993	$ 79,188	$ 448,015	5,978
2006/07	$ 343,271	$ 38,869	$ 82,162	$ 464,302	5,988
2007/08	$ 357,690	$ 41,709	$ 85,865	$ 485,263	6,071
2008/09	$ 376,985	$ 45,447	$ 90,858	$ 513,290	6,276
2009/10	$ 404,576	$ 50,646	$ 97,226	$ 552,448	6,429
2010/11	$ 422,240	$ 50,655	$ 101,391	$ 574,286	6,594
2011/12	$ 448,032	$ 54,936	$ 107,247	$ 610,214	6,608
2012/13	$ 464,158	$ 60,953	$ 143,889	$ 668,999	6,678
2013/14	$ 476,693	$ 62,284	$ 161,336	$ 700,312	6,756
2014/15 Forecast	$ 499,655	$ 61,709	$ 174,709	$ 736,074	6,864
2015/16 Forecast	$ 521,217	$ 71,080	$ 182,587	$ 774,884	6,902
2016/17 Forecast	$ 530,458	$ 73,121	$ 185,883	$ 789,462	6,814

Section:	Tab 5	Page No.:	Appendix 11.27
Topic:	Financial Results and Forecast		
Subtopic:	OM&A Expense		
Issue:	Expense Growth		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain factors behind the ten-year growth rates in excess of 10% to 2013/14 for Generation Operations, Transmission and Customer Service & Distribution.

b) Please explain the major increase in Licensing & Relationship Management incurred in 2013/14 and forecast for 2014/15.

RATIONALE FOR QUESTION:

To explore reasons from OM&A increases.

RESPONSE:

a) The ten year growth rate for Generation Operations, Transmission, and Customer Service and Distribution are 4%, 6.2% and 3.8% respectively and is primarily driven by increases in the following divisions.

The Power Planning Division within the Generation Operations business unit has a 10 year growth rate of 10.1% to 2013/14. The factors contributing to the higher growth rate are related to greater resource requirements for water resources engineering, environmental licensing and protection, and energy policy and resource analysis. The increase also reflects impacts of contract settlements and greater benefit costs primarily as a result of changes in the discount rate. In addition, consulting costs increased as a result of environmental monitoring requirements for 35 Sutherland and more recently at Wuskwatim.

The VP Transmission Administration Division within the Transmission business unit has a 10 year growth rate of 28.2% to 2013/14 as a result of increased trainee requirements through the years to meet current and expected attrition levels. The increase also reflects impacts of contract settlements and increased benefit costs primarily as a result of changes in the discount rate.

The Business Support & Capital Management (BS&CAM) division within the Customer Service & Distribution (CS&D) business unit has a 10 year growth rate of 10.9% primarily due to new positions to support Mobile Workforce Management, Asset Maintenance, Forestry Management and Risk Management programs. In addition, positions were transferred from other divisions within the business unit to centralize CS&D business systems support and field safety operations. The increase also reflects impacts of contract settlements and increased benefit costs primarily as a result of changes in the discount rate.

b) The Licensing & Relationship Management Division within the Major Capital Projects business unit experienced an increase in 2013/14 mainly related to a full year of implementation costs for the Wuskwatim Generating Station. In addition, the increase reflects the impacts of contract settlements and higher benefit costs primarily due to changes in the discount rate.

The forecast increase for Licensing & Relationship Management in 2014/15 is primarily due to contract settlements and associated benefit costs as well as fewer travel requirements in 2013/14. Conversely, the Division has experienced a decrease in 2015/16 primarily due to the elimination of the one-time implementation costs for Wuskwatim and a reduction of staff as a result of the suspension of Conawapa.

Section:	Tab 5 Appendix 5.7	**Page No.:**	Appendix 11.10
Topic:	Financial Results & Forecasts		
Subtopic:	OM&A		
Issue:	Quarterly Report Results		

PREAMBLE TO IR (IF ANY):

MH realized the $9 million decrease in operating expenses for the nine-month period ended December 31, 2014.

QUESTION:

a) Please provide an analysis that explains the reported decrease in OM&A costs for the 9 months ended December 31, 2014.

b) Please indicate whether OM&A is trending lower than forecast for 2014/15 given the results to date.

RATIONALE FOR QUESTION:

To explore current OM&A levels.

RESPONSE:

a) The $9 million decrease in operating expenses for the nine-month period ended December 31, 2014 referenced in Appendix 11.10 is for electric operations including subsidiaries. Excluding subsidiaries, the decrease for the period was $11.8 million and an analysis of the decrease has been provided in the response to PUB/MH-I-72.

b) OM&A for Electric Operations to the end of February 2015 has been trending lower than forecast.

Section:	Tab 5: App 5.6	**Page No.:**	Appendix 11.49 Attachment B
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation Expense		
Issue:	ELG vs ASL		

PREAMBLE TO IR (IF ANY):

In its October 22, 2014 letter MH stated:

> *"In the event that the PUB determines that the ELG method should not be used for rate-setting purposes, Manitoba Hydro could continue to use the existing CGAAP ASL depreciation rates for setting customer rates. However, in consideration of Manitoba Hydro's existing asset component structure, Manitoba Hydro is adopting the ELG method for IFRS compliant financial reporting purposes (as opposed to rate setting purposes). In this circumstance, Manitoba Hydro would be required, for financial reporting purposes, to establish a rate-regulated account to capture the difference between depreciation expense recorded for rate-setting purposes (existing CGAAP ASL methodology) and depreciation expense that will be recorded for financial reporting purposes (ELG methodology). The approach to capture the differences in a rate-regulated account is an interim measure for rate-setting purposes and would subsequently have to be re-examined at a future GRA."*

QUESTION:

Please indicate whether MH has discussed with its auditors the continued use of ASL for rate setting purposes. If so, please provide the auditors' report.

RATIONALE FOR QUESTION:

To explore the use of a different depreciation methodology for rate-setting.

RESPONSE:

In Manitoba Hydro's letter of October 22, 2014, the approach to capture in a rate regulated account the difference between depreciation expense recorded for rate setting purposes using the existing CGAAP ASL methodology and depreciation expense recorded for financial reporting purposes using the ELG methodology was identified as an interim measure only in the event that the PUB did not accept ELG for rate-setting purposes. PUB/MH-II-21c identifies the impacts associated with the requirement to maintain two sets of PP&E sub-ledger records on an ongoing basis to support the net income before and after regulatory balances as presented in the financial statements. The response to PUB/MH-II-21b also indicates that the rate increases assuming the continued use of ASL under CGAAP for rate-setting purposes are essentially the same as for the use of ELG for rate-setting purposes, thus providing no benefit to customers for the added costs.

While Manitoba Hydro has discussed with its auditors Ernst & Young the use of a regulatory deferral account for capturing the difference between depreciation used for rate-setting purposes and depreciation used for financial reporting purposes, the Corporation does not have a formal report on this matter.

Section:	Tab 5: App 5.6	**Page No.:**	Appendix 11.49
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation Expense		
Issue:	ASL vs ELG		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro filed a response to Directives 8 and 9 of Board Order 43/13 as Appendix 11.49, which attaches a study prepared by Gannett Fleming.

QUESTION:

a) Please provide, in electronic format with formulae intact, the Gannett Fleming file or files used to produce Tables 1-4.

b) Please explain the significance of the life span date Tables 1-4 of the Gannett Fleming document in Appendix 11.49 and how it factors into the determination of the calculated annual accrual amount.

RATIONALE FOR QUESTION:

RESPONSE:

a) Please see the attached electronic files as prepared by Gannett Fleming and used to produce tables 1-4 in Appendix 11.49.

- PUB-MH-II-55a – Attachment 1. xlsx
- PUB-MH-II-55a – Attachment 2. xlsx
- PUB-MH-II-55a – Attachment 3. xlsx
- PUB-MH-II-55a – Attachment 4. xlsx

b) The following response was provided by Gannett Fleming:

The significance of the life span date in the Gannett Fleming document in Tables 1-4 of Appendix 11.49 is that the resulting survivor curve is truncated at a specific point in time rather than a gradual reduction in percent surviving to zero. As such, the composite remaining life of all vintages is shortened to reflect the retirement of all remaining investment as at the truncation date.

The basis for the life span is a term used by depreciation professionals to describe both a unit property and a group property that will be retired as a unit. Such is the case of Manitoba Hydro's generating assets "unit of property." Examples of a group of property that will retire as a unit include the turbines, generators, and other equipment used to generate electrical power and housed in either the dam or building. Irrespective of the two, the life of the dam or the building and the life of the equipment housed in the facility are mutually inclusive in that the retirement of one usually causes the retirement of the other. The dispersion pattern of retirements from a group life span property differs from the pattern of other property because much of the life span is retired simultaneously, which results in the truncation of the survivor curve rather than the usual gradual curve of zero percent surviving. With a determined life span date or termination date, all accumulated depreciation must be completed by the specified end date. This will cause the accrual amount to vary in its collection and will either shorten or lengthen the time frame depending on the termination date. The termination date is a definitive time period which will be adhered to and the resulting outcomes to the accrual amount will be determined accordingly.

Section:	Tab 5: App 5.6	**Page No.:**	Appendix 11.49, page II-3
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation Expense		
Issue:	ASL vs ELG		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's head office building was included in the accounts tested by Gannett Fleming.

QUESTION:

a) Please explain why a head office account 'Buildings 360 Portage-Electro/mechanical' was utilized in the analysis and how it is representative of the plant in-service of a hydroelectric utility subject to depreciation based on the stated criteria for selecting representative sample components for extrapolation purposes.

b) Please provide the supporting calculations for the extrapolation of a $3.5 million difference in depreciation expense related to the existing plant in service.

c) Please provide an alternative extrapolation of the depreciation expense related to net plant removing the building account 360 portage – Electro/Mechanical from the testing an compare the extrapolated results with that represented in the study.

RATIONALE FOR QUESTION:

To explore depreciation expense.

RESPONSE:

a) In order to perform a comparison of the impacts of a greater level of componentization under the ASL method as compared to the ELG method, a broad range of asset types is required. This ensures the conclusions drawn from the study are representative of Manitoba Hydro's asset base. The 360 Portage Head Office location is representative of the Corporation's administrative building asset category.

b) The supporting calculations for the extrapolation of the difference between the ASL and ELG depreciation results is as follows:

		('000's)
Difference Between the ELG and ASL Depreciation Results	$	738
March 31, 2014 Surviving Original Asset Base Tested	$	2,887,794
March 31, 2014 Manitoba Hydro Total Surviving Original Asset Base	$	14,230,426
Extrapolation across total Manitoba Hydro Surviving Original Asset Base*	$	3,639

* ($738 x $14,230,426) / $2,887,794

Given that this test was performed on a sample basis, Manitoba rounded the balances for determining the extrapolated amount referenced in Appendix 11.49 of $3.5 million.

c) Please see below for an extrapolation of the depreciation expense related to net plant assuming the removal of the building account 360 portage – Electro/Mechanical from the testing:

		('000's)
Difference Between the ELG and ASL Depreciation Results less 360 Portage	$	870
March 31, 2014 Surviving Original Asset Base Tested less 360 Portage	$	2,810,455
March 31, 2014 Manitoba Hydro Total Surviving Original Asset Base	$	14,230,426
Extrapolation across total Manitoba Hydro Surviving Original Asset Base*	$	4,405

* ($870 x $14,230,426) / $2,810,794

The extrapolated amount for this scenario would be approximately $4.4 million.

Section:	Tab 5: App 5.6	**Page No.:**	Appendix 11.49
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation Expense		
Issue:	ASL vs ELG		

PREAMBLE TO IR (IF ANY):

The Transmission Lines for the project have a capital cost of $1.7 billion and represents about 36% of the capital costs of Bipole III. The analysis tested $700 million or 26% of the $2.7 billion converter station costs representing about 15% of the total project costs for extrapolation purposes. Metal Towers and Concrete Poles appears to be the largest account group in the Transmission Depreciation Accounts.

QUESTION:

a) Please identify the account groups the Bipole III transmission lines are proposed to be depreciated under ELG and the proposed rate.

b) Please indicate what additional component groups Metal Towers and Concrete Poles would need to be broken down into for ASL based IFRS compliant. Provide the respective life span dates, survivor curve and annual accrual effective depreciation rate.

c) Please provide examples of other Utilities' IFRS-compliant breakdown of Transmission Lines for depreciation purposes.

d) Please indicate what the Metal Tower and Concrete Poles ASL based rate would be excluding the 25% Net Salvage and compare this with the 1.23% ELG based rate

e) Please update the comparative analysis including the Metal Towers and Concrete Poles in the analysis.

RATIONALE FOR QUESTION:

To test the extrapolation analysis

RESPONSE:

a) The depreciation charges for the Bipole III transmission line will be recognized in all the account groups included in the Transmission category as listed in the 2014 Depreciation Study in Attachment 2 of Appendix 5.6., with the exception of the ground line treatment component.

b) As identified on page 12 of Appendix 11.49 of the application, Metal Towers and Concrete Poles could potentially be broken down further between the towers and the concrete footings upon which they are fastened. The concrete footings were identified as a likely component that could be separated from the metal towers given recent years experience with having to repair and replace many cracked / sunken footings. The costs to install and repair the footings are material and recent years experience indicates they are not lasting as long as the metal towers that are fastened to them.

The detailed analysis required to provide the respective average service life, survivor curve and annual accrual effective depreciation rate has not been performed as Manitoba Hydro is not using an IFRS compliant ASL method upon transition to IFRS. Similar to other significant asset components, the information required to perform this analysis is not readily available as historical plant costs for the installation of the footings were not typically captured separately from the costs of installing the towers.

c) Manitoba Hydro is only familiar at a detailed level with its own circumstances with respect to its transmission system costs and under which components such costs are recorded. Component groupings have been supplied in the response to MIPUG-MH-I-16 (a) for utilities such as BC Hydro, AltaLink and SaskPower which are reporting under IFRS.

d) The Metal Tower and Concrete Poles CGAAP ASL based depreciation rate excluding the 25% Net Salvage is 1.16% compared the 1.23% ELG based rate.

Please see the response to PUB/MH-II-21b and PUB/MH-II-21c for a discussion regarding the impacts associated with using the CGAAP ASL method of depreciation for rate setting purposes.

e) The analysis in Appendix 11.49 shows a comparison of an IFRS compliant ASL method to the ELG method. As indicated in part (b) to this response, the detailed analysis has not been performed in order to be able to separate the costs of the Metal Towers and Concrete Poles component between the towers and concrete footings. As such, the information required to provide an update to the comparative analysis in Appendix 11.49 is not available.

Section:	Tab 7, App. 7.1	**Page No.:**	Table 14, p.18
Topic:	Electric Load Forecast		
Subtopic:	Domestic Load Forecasts Residential Sales Forecasts		
Issue:	Electric Heating		

PREAMBLE TO IR (IF ANY):

MH's Residential Sales forecasts suggest an ongoing shift to electric heat and water heating.

QUESTION:

Provide a definition and calculation of a typical residential customer in Winnipeg and in Thompson.

RATIONALE FOR QUESTION:

To understand the magnitude of future electric heating energy bills.

RESPONSE:

For purposes of this response, Manitoba Hydro has defined an average residential customer to include all customers residing in single detached, multi-attached or apartment suite dwellings within the community noted. Variations in the demographics of each community will influence the average amount of electricity consumed per residential customer; differences in the distribution of housing types, housing sizes, and saturation of electric space and water heating will influence the average annual electricity consumption by a residential customer.

The following outlines the demographics of Winnipeg and Thompson based upon the 2009 Residential Energy Use Survey:

Community Demographics	Thompson	Winnipeg
Total Number of Dwellings	4 237	237 829
Average Square Feet of Dwelling	1 318	1 198
Average Year Built	1968	1963
% Electric Space Heat Billed[1]	61.4%	11.6%
% Electric Water Heat Billed[1]	82.4%	22.5%
% Gas Space Heat Billed[1]	0.0%	73.9%
% Gas Water Heat Billed[1]	0.0%	58.3%
% Central Air Conditioning	6.2%	68.9%
Distribution of Dwelling Types by Community		
% Single Detached	74.1%	69.2%
% Multi-Attached	15.5%	11.2%
% Apartment Suites	10.4%	19.5%
Weather Factors by Community		
25 Year Average Degree Days Heating (Base 14)	6302	4570
25 Year Average Degree Days Cooling (Base 18)	44	183

Note: 1. The % of Space Heat Billed and the % of Water Heat Billed reflects the number of customers that have their space or water heating recorded on their individual electricity or natural gas bills compared to the total number of residential customers. Some residential customers, such as those residing in apartment suites, may be heated from a central or common source and not directly billed for space and/or water heating.

The table below provides a calculation of the annual energy usage and the associated total annual energy bill for an average residential customer, as previously defined, situated in Winnipeg or Thompson. Please note that the calculation of average electrical usage and bills represents all residential customers, including both standard and all-electric customers. For Winnipeg the average electric bill and the average natural gas bill may not be additive.

	WINNIPEG				**THOMPSON**	
2013/14	AVERAGE ANNUAL KWH	AVERAGE ANNUAL ELECTRIC BILL	AVERAGE ANNUAL M3	AVERAGE ANNUAL NATURAL GAS BILL	AVERAGE ANNUAL KWH	AVERAGE ANNUAL ELECTRIC BILL
Actual	10 542	$842	2 714	$875	25 946	$1 949
Weather Adjusted	10 115	$812	2 342	$771	23 671	$1 785

Note: Electric bill amounts are based on May 1, 2013 PUB approved rates. Natural gas bill amounts are based on PUB approved rates in place during the 2013/14 fiscal year applied to actual and normalized consumption for an average Winnipeg residential customer. In Winnipeg in 2013/14, there were 248 730 electric customers and 184 138 natural gas customers.

Section:	Tab 7, App. 7.1	**Page No.:**	Table 14, p.18
Topic:	Electric Load Forecast		
Subtopic:	Domestic Load Forecasts Residential Sales Forecasts		
Issue:	Electric Heating		

PREAMBLE TO IR (IF ANY):

MH's Residential Sales forecasts suggest an ongoing shift to electric heat and water heating.

QUESTION:

Provide a typical residential total energy bill comparison for all-electric vs. natural gas space and water heating customers in Winnipeg for the next ten years.

RATIONALE FOR QUESTION:

To understand the magnitude of future electric heating energy bills.

RESPONSE:

The following tables provide the forecast average annual energy usage and the respective estimated annual bill amounts for residential standard and residential all-electric customers from 2015 to 2024. Manitoba Hydro notes that load forecasts are prepared on an aggregate level and as such, separate load forecasts for residential customers situated in Winnipeg or Thompson are not available. Electric and natural gas load forecast information is therefore shown on a province-wide basis.

Annual electric energy bills are estimated by applying the forecast usage per customer in each year by Manitoba Hydro's proposed and indicative rates. Annual natural gas bills have been estimated by applying the forecast natural gas usage per customer and February 1, 2015 natural gas rates.

Average Annual All-Electric Bill:

	ANNUAL ELECTRIC BILL	
YEAR ENDING	AVERAGE YRLY KWH	**ANNUAL ELECTRIC BILL**
2015	24,913	$1,926
2016	24,776	$1,992
2017	24,693	$2,064
2018	24,601	$2,138
2019	24,501	$2,213
2020	24,419	$2,293
2021	24,341	$2,377
2022	24,280	$2,465
2023	24,230	$2,557
2024	24,192	$2,654

Average Annual Standard Electric (Non-Electric Heat) Bill:

	ANNUAL ELECTRIC BILL (Non-Heating)		ANNUAL NATURAL GAS BILL		
YEAR ENDING	ANNUAL KWH	ANNUAL ELECTRIC BILL	ANNUAL m3	ANNUAL GAS BILL	**TOTAL ANNUAL ENERGY BILL**
2015	10,377	$853	2,271	$766	$1,619
2016	10,412	$890	2,232	$755	$1,645
2017	10,484	$931	2,188	$744	$1,675
2018	10,538	$972	2,176	$741	$1,713
2019	10,577	$1,013	2,166	$738	$1,751
2020	10,625	$1,058	2,159	$736	$1,794
2021	10,663	$1,103	2,150	$734	$1,837
2022	10,706	$1,151	2,143	$732	$1,883
2023	10,749	$1,253	2,109	$723	$1,926
2024	10,794	$1,253	2,077	$715	$1,968

Notes:

1) 2014/15 electric bill amounts based on May 1, 2014 rates
2) 2015/16 electric bill amounts based on proposed April 1, 2015 rates
3) 2016/18 – 2023/24 electric bill amounts are based on proposed April 1, 2016 rates, escalated by 3.95% each year
4) Gas bill amounts based on February 1, 2015 rates, and are not escalated.
5) All bills calculations do not include taxes

Section:	Tab 7, App. 7.1	**Page No.:**	Table 14, p.18
Topic:	Electric Load Forecast		
Subtopic:	Domestic Load Forecasts Residential Sales Forecasts		
Issue:	Electric Heating		

PREAMBLE TO IR (IF ANY):

MH's Residential Sales forecasts suggest an ongoing shift to electric heat and water heating.

QUESTION:

Provide a typical residential total energy bill for an all-electric customer in Thompson for the next ten years.

RATIONALE FOR QUESTION:

To understand the magnitude of future electric heating energy bills.

RESPONSE:

A residential customer situated in Thompson is assumed to be an all-electric residential account.

Please see Manitoba Hydro's response to PUB/MH-II-58b which provides forecast average annual energy usage and respective annual bills for standard and all-electric residential customers on a province-wide basis.

Section:	Tab 7, App. 7.1	**Page No.:**	Table 14, p.18
Topic:	Electric Load Forecast		
Subtopic:	Domestic Load Forecasts Residential Sales Forecasts		
Issue:	Electric Heating		

PREAMBLE TO IR (IF ANY):

MH's Residential Sales forecasts suggest an ongoing shift to electric heat and water heating.

QUESTION:

Provide Manitoba Hydro's Home Heating Cost Comparison charts for the past three years and file a graph that shows the average heating cost for an all-electric residential household and for a gas space and water heat household for each of these documents.

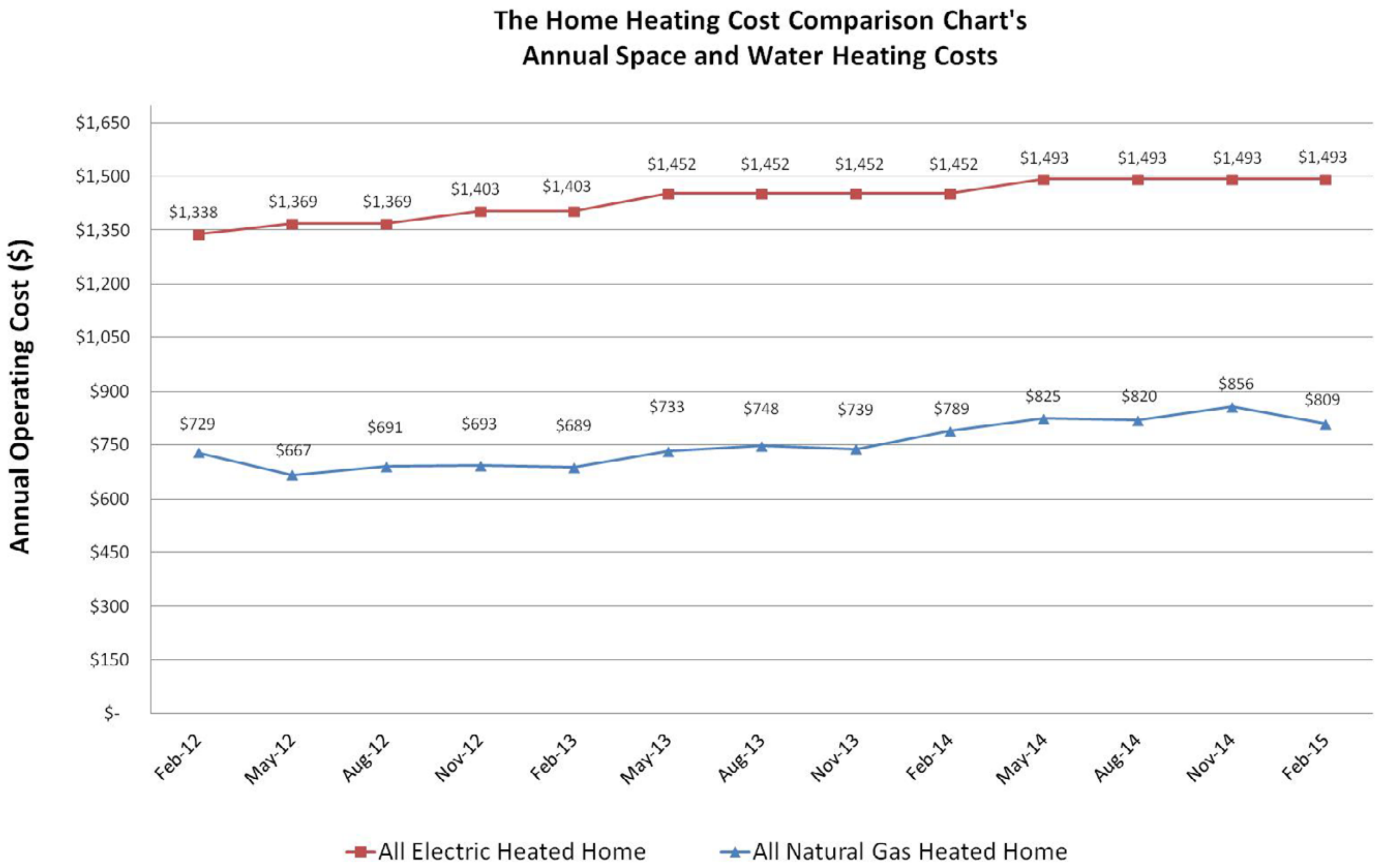
RATIONALE FOR QUESTION:

To understand the magnitude of future electric heating energy bills.

RESPONSE:

Please see the attachment to this response for copies of Manitoba Hydro's Home Heating Cost Comparison charts for the past three years. To compare all energy sources on an equivalent basis the Heating Cost Comparison Chart uses an output space heating requirement of 60 Gigajoules to calculate annual space heating costs and water consumption assuming a household with 2.4 people consuming 140 litres of water per day heated to a temperature rise of 50 C to calculate domestic water heating costs.

The following graph presents a summary of the annual costs of heating with electricity compared to heating with natural gas based upon these charts. For the purposes of this example, the all electric heated home assumes an electric furnace for space heating and a 40 gallon electric water heater for domestic water heating. The natural gas heated home assumes a high-efficiency (92% SE) natural gas furnace for space heating and a conventional natural gas water heater (0.59 EF) for domestic water heating.


The Home Heating Cost Comparison Chart's
Annual Space and Water Heating Costs
Annual Operating Cost ($)
$1,650
$1,500
$1,350
$1,200
$1,050
$900
$750
$600
$450
$300
$150
$-
$1,338
$1,369
$1,369
$1,403
$1,403
$1,452
$1,452
$1,452
$1,452
$1,493
$1,493
$1,493
$1,493
$729
$667
$691
$693
$689
$733
$748
$739
$789
$825
$820
$856
$809
Feb-12
May-12
Aug-12
Nov-12
Feb-13
May-13
Aug-13
Nov-13
Feb-14
May-14
Aug-14
Nov-14
Feb-15
All Electric Heated Home
All Natural Gas Heated Home

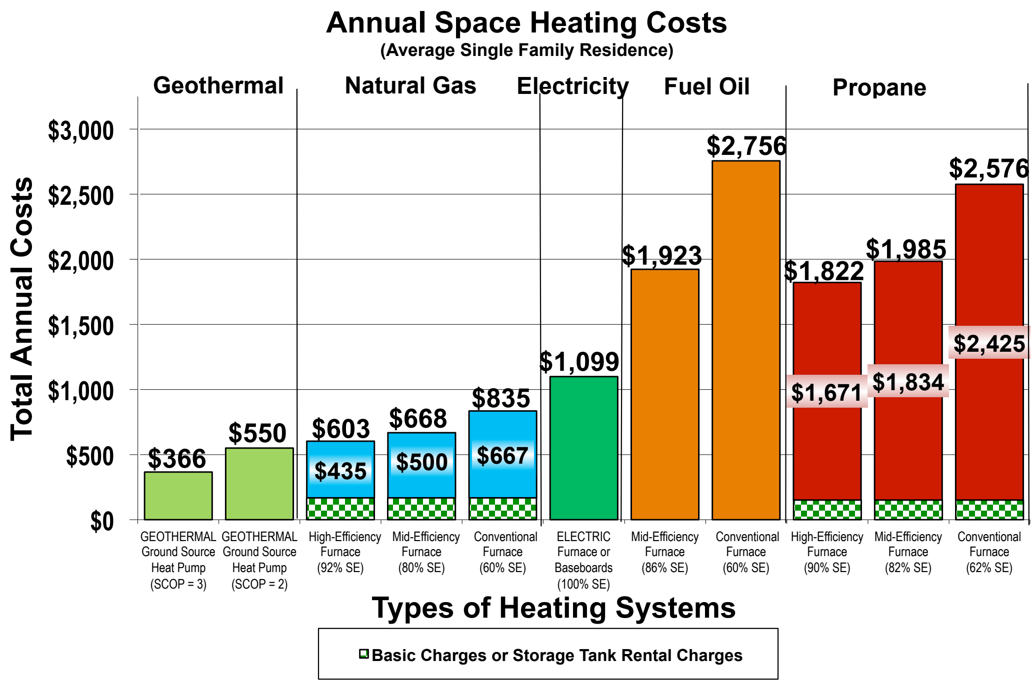
Typical space & water heating costs

Average single family residence at rates in effect February 1, 2012

1

Wondering about your energy options for heating?

1. Consult the charts to identify the costs of your current home heating and water heating systems.
2. Review the costs of other systems to see how your costs compare.
3. Consult the accompanying notes for guidance if you are thinking of switching systems or building a new home.



Energy rates

Natural gas:
$0.2492/cubic metre

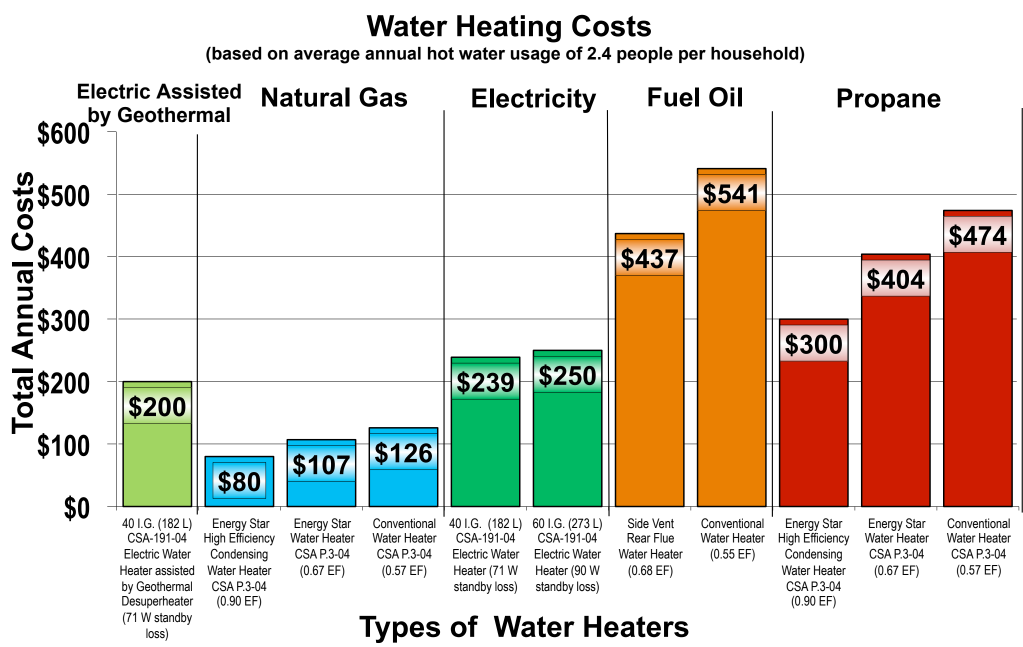
Electricity:
$0.0662/kilowatt-hour

Fuel oil:
$1.065/litre

Propane:
$0.642/litre

Basic monthly charge for natural gas is **$14** (**$168** per year)

Annual propane tank rental: **$151**



Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect February 1, 2012

2

Weigh your options

The home heating costs shown in the chart are based on the amount of gas used to heat the average natural gas-heated home served by Manitoba Hydro. This average home is about 1200 square feet and uses a mid-efficiency furnace and conventional gas water heater. Your heating costs may differ due to a variety of factors, such as weather, heating equipment, insulation levels, air tightness and lifestyle. Water-heating costs are based on typical usage of the average Manitoba household of 2.4 people.

Annual cost estimates

The charts present annual costs as if all energy rates remained fixed for the coming year at rates in effect on February 1, 2012.

Your actual annual costs will vary, since natural gas rates change four times a year, while propane and oil rates can change weekly. Note that Primary Gas represents the bulk of the gas used. With Manitoba Hydro's Quarterly Rate Service, the price you pay for Primary Gas is the same price we pay for the gas in the marketplace. This rate changes every 3 months and is currently $0.1105 per cubic metre. If you buy Primary Gas on a Fixed Rate Service contract from Manitoba Hydro or a Gas Broker, you will continue to pay Manitoba Hydro for Supplemental Gas as well as transportation and distribution charges. The figure of $0.2492 per cubic metre of natural gas that we've used in the charts is known as a "re-bundled" effective rate. It includes charges for Primary and Supplemental gas, as well as for transportation and distribution of the gas on Manitoba Hydro's Quarterly Rate Service.

Key points if you are thinking of converting

Is it economically feasible?

Note that the costs of switching to another system to heat your home and hot water may be economically feasible only if your current system is at or near the end of its useful life, or if you are building a new home. Be sure to obtain quotations from at least three reputable heating contractors before you make your decision.

Conventional furnaces no longer manufactured

The space heating chart includes conventional natural gas, fuel oil, and propane furnaces. These conventional furnaces have not been manufactured since 1992, but many are still in operation.

High efficiency furnaces are now required by law

Effective December 30, 2009 the Province of Manitoba enacted legislation controlling the sale and lease of gas and propane heating equipment. Visit www.greenmanitoba.ca (click on the energy tab) for more information on this regulation.

Size of existing electrical service

Your electrical system may need to be upgraded if you want it to carry a heating load.

Depending on the capacity of the electrical appliances and equipment currently installed, and the size of your home, the Manitoba Electrical Code will allow a maximum of 8 to 10 kilowatts of electric heating on a standard 100-amp service. Most homes will need more than this.

Increasing the size of an electrical service usually involves changing your electrical panel or installing an additional one. An electrician should perform an electrical code load calculation to advise whether your existing service is adequate to serve the heating equipment required to heat your home.

Other gas appliances

If you have other appliances in your home like a range, clothes dryer, fireplace, or swimming pool heater, switching to an all-electric system may be quite costly.

Flue Gas Venting

When natural gas is burned, flue gases are produced which primarily contain carbon dioxide and water vapour which are not harmful to people. However, flue gases can also contain trace amounts of carbon monoxide and other gases that can present a health hazard. High-efficiency natural gas furnaces will not use the existing chimney to vent (remove) flue gases from the home. Instead they will be vented via approved plastic piping through the home's side wall or roof.

If you have a standard natural gas water heater, the Manitoba Gas Notices allow it to continue to use the existing chimney if it is in good condition and meets the requirements of the Code Authority Having Jurisdiction (Manitoba Dept. of Labour). Your heating contractor should inform you if the chimney has corroded or does not meet the code requirements. Generally, installing a new approved smaller diameter chimney liner may meet the requirements.

Issues that can arise once the natural gas water heater vents alone on the old chimney include: flue gases condensing in the chimney, or flue gas spillage into the home. If these venting problems occur, you may need to upgrade you venting system or have other work performed to rectify them. If the upgrades are costly, other options to consider are replacing the conventional heater with a side-wall vented gas water heater or an electric water heater.

Reduced chimney ventilation

Converting to electric heat or to a high-efficiency gas furnace will reduce the uncontrolled ventilation provided by the chimney. The uncontrolled chimney ventilation will be completely eliminated if you also replace your conventional gas water heater and either remove or cap off the chimney.

With a conventional gas furnace, warm moist air continuously exits the house through the chimney. This draws cold and dry replacement air into the house through cracks in walls and around windows and doors. This uncontrolled ventilation dehumidifies your home in winter, but consumes heating energy.

Reducing or eliminating this chimney ventilation can save energy but may also increase humidity levels and change the way that air leaks into and out of your home. Homes usually become slightly more positively pressurized.

The increase in humidity and change in air leakage patterns may cause increased condensation/icing: on interior surfaces of well-sealed windows, and anywhere warm moist air leaks out of the home such as electrical outlets, between the panes of poorly sealed windows, on door seals, in door lock mechanisms and around chimney and plumbing stacks. A very small percentage of homeowners have reported experiencing some of these issues.

There is not one solution that works in every home and for every issue. Here are some of the measures that individually or in combination can minimize or eliminate the effects of reduced chimney ventilation:

- improved weatherstripping and caulking on doors and windows and other areas of air leakage (but not on storm doors)
- seasonal window insulator kits (clear heat shrink poly over inside windows and frames)
- improved windows (preferably triple pane)
- a ventilation system which may consist of:
  - exhaust fan(s)
  - exhaust fan(s) combined with a fresh air intake
  - heat recovery ventilator (HRV)

Manitoba Hydro
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Typical space & water heating costs

Average single family residence at rates in effect February 1, 2012

3

Carbon monoxide safety

If you are burning heating oil, diesel, propane, kerosene, natural gas, wood, or coal in your home, or if you have an attached garage, we recommend that you install at least one carbon monoxide detector in your home.

The building code now requires permanently mounted carbon monoxide detectors in all new homes with fuel burning appliances or attached garages.

For further details, contact us for a copy of our brochure on "Carbon monoxide safety — Because your family comes first!"

What is the payback?

Determining how many years it will take for a new heating system to pay for itself may help you reach a decision.

Determine the potential savings

Subtract the annual cost of the new heating system you are considering from the annual cost of your current heating system (check the charts).

The difference is approximately what you can expect to save each year, at current energy rates.

Determine the costs of the new system

Determine how much it will cost to buy and install the new system, along with any other adjustments required. Get quotations from three reputable contractors.

Factor in the cost of financing, if necessary.

Determine the payback

Divide the estimated cost of switching your system, by the estimated savings.

The result is the number of years it will take for the new system to pay for itself.

Explanation of technical information in the charts

- Typical annual home heating requirement (output) of 60 Gigajoules is based on Manitoba Hydro's system average for natural gas heated homes.
- Water heating usage is based on Manitoba Hydro's average electric and natural gas water heating household of 2.4 people consuming about 140 litres per day that are heated up an average temperature rise of 50 C.
- The Electric water heating assisted by geothermal desuperheater option is based on Manitoba Hydro's field monitoring of nine homes with geothermal heating and desuperheaters where 80 per cent of the average water heating load was provided by the electric heating elements of the water tank and 20 per cent by the desuperheater.
- The cost of heating with propane includes a propane tank rental or lease charge of $151 per year for a typical 500 US gallon tank. See table below. This charge may not apply to all customers and may vary.
- The cost of space heating with natural gas includes a basic monthly charge of $14 ($168 per year).
- SE (seasonal efficiency) is defined as the total heat output delivered by the furnace during one heating season as a percentage of the total energy input to the system. SE takes into consideration not only normal operating losses but also the fact that most furnaces rarely run long enough to reach their steady-state efficiency temperature, particularly during milder weather at the beginning and end of the heating season.
- Energy Factor (EF) is an overall efficiency rating of the water heater. The higher the EF, the more efficient the model. Electric water heaters are required to have maximum standby losses of 71 watts for a 40 gallon and 90 Watts for a 60 gallon.
- SCOP (Seasonal Coefficient of Performance) = 2 and = 3 appears in the home heating chart under geothermal closed loop heat pump. It refers to the Seasonal Coefficient of Performance of the heat pump over an entire heating season.

  SCOP is defined as the total heat output of the system during the heating season, divided by the total energy input to the system.

  The SCOP of a geothermal heat pump system typically ranges from 2.0 to 3.0. For reference, the SCOP of an electric baseboard heater is 1.0. The SCOP rating accounts for cycling losses, circulating fan and pump energy and auxiliary electric heating loads which are not included in the manufacturer's COP rating of the heat pump "unit". The overall system SCOP will therefore always be significantly lower than the unit COP.

  The SCOP of a geothermal system can vary significantly and is highly dependent on the quality of the system design, installation, commissioning and ongoing maintenance practices.
- Note that the natural gas energy price reflected in the charts is a bundled price that includes primary and supplemental gas, and transportation and distribution charges. For reference, one of the major components of the bundled price is the price of Primary Gas, at $0.1105 per cubic metre. Primary Gas currently comprises 99 per cent of the gas supplied (supplemental gas is 1 per cent.)
- Taxes are not included in these calculations and costs.

ENERGY RATES — in effect February 1, 2012

	Commodity charge	Heating value	
Natural gas	$0.2492/cubic metre	35,310	Btu/cubic metre
Electricity	$0.0662/kilowatt-hour	3,413	Btu/kilowatt-hour
Fuel oil	$1.065/litre	36,500	Btu/litre
Propane	$0.642/litre	24,200	Btu/litre

Manitoba Hydro
POWER SMART*

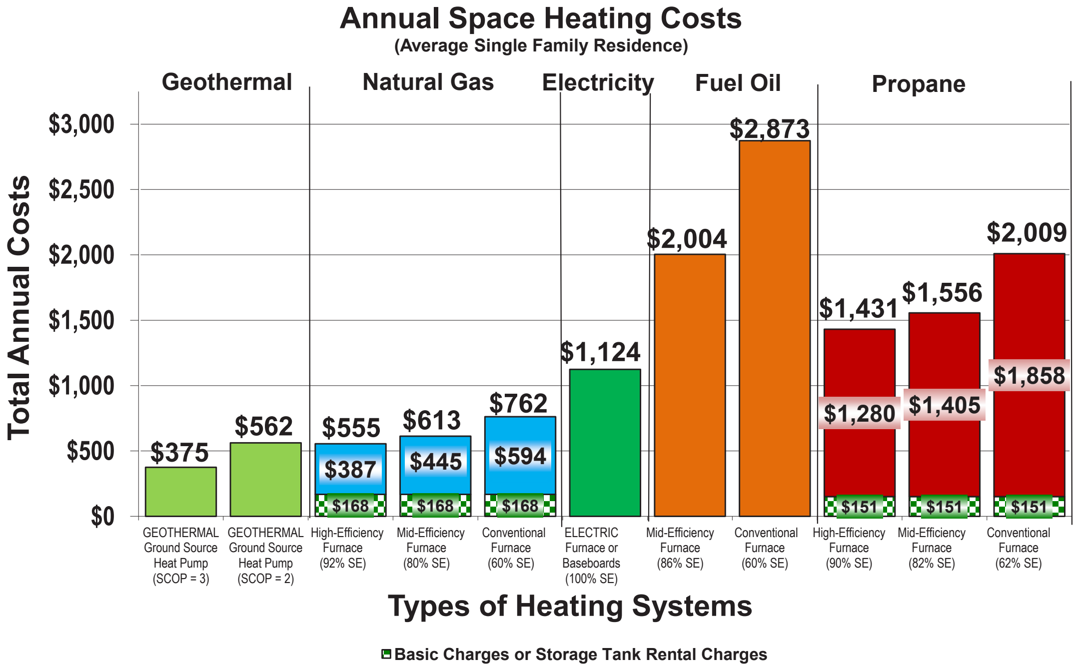
Typical space & water heating costs

Average single family residence at rates in effect May 1, 2012

1

Wondering about your energy options for heating?

1. Consult the charts to identify the costs of your current home heating and water heating systems.
2. Review the costs of other systems to see how your costs compare.
3. Consult the accompanying notes for guidance if you are thinking of switching systems or building a new home.



Energy rates

Natural gas:
$0.2220/cubic metre

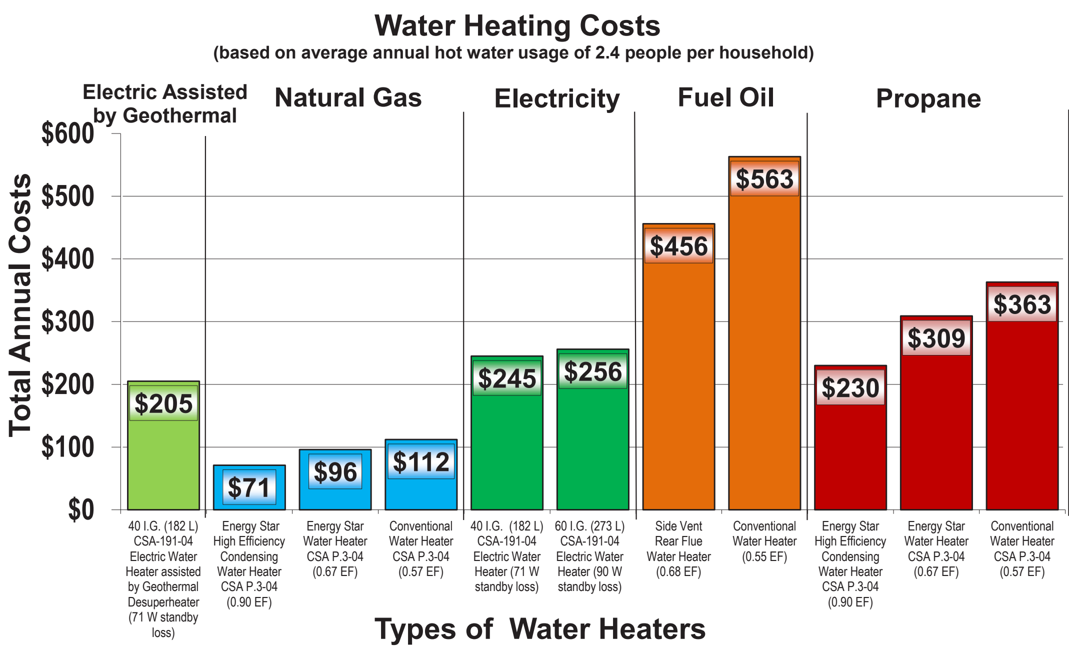
Electricity:
$0.0677/kilowatt-hour

Fuel oil:
$1.11/litre

Propane:
$0.492/litre

Basic monthly charge for natural gas is **$14** (**$168** per year)

Annual propane tank rental: **$151**



Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect May 1, 2012

2

Weigh your options

The home heating costs shown in the chart are based on the amount of gas used to heat the average natural gas-heated home served by Manitoba Hydro. This average home is about 1200 square feet and uses a mid-efficiency furnace and conventional gas water heater. Your heating costs may differ due to a variety of factors, such as weather, heating equipment, insulation levels, air tightness and lifestyle. Water-heating costs are based on typical usage of the average Manitoba house-hold of 2.4 people.

Annual cost estimates

The charts present annual costs as if all energy rates remained fixed for the coming year at rates in effect on May 1, 2012.

Your actual annual costs will vary, since natural gas rates change four times a year, while propane and oil rates can change weekly. Note that Primary Gas represents the bulk of the gas used. With Manitoba Hydro's Quarterly Rate Service, the price you pay for Primary Gas is the same price we pay for the gas in the marketplace. This rate changes every 3 months and is currently $0.0888 per cubic metre. If you buy Primary Gas on a Fixed Rate Service contract from Manitoba Hydro or a Gas Broker, you will continue to pay Manitoba Hydro for Supplemental Gas as well as transportation and distribution charges. The figure of $0.2220 per cubic metre of natural gas that we've used in the charts is known as a "re-bundled" effective rate. It includes charges for Primary and Supplemental gas, as well as for transportation and distribution of the gas on Manitoba Hydro's Quarterly Rate Service.

Key points if you are thinking of converting

Is it economically feasible?

Note that the costs of switching to another system to heat your home and hot water may be economically feasible only if your current system is at or near the end of its useful life, or if you are building a new home. Be sure to obtain quotations from at least three reputable heating contractors before you make your decision.

Conventional furnaces no longer manufactured

The space heating chart includes conventional natural gas, fuel oil, and propane furnaces. These conventional furnaces have not been manufactured since 1992, but many are still in operation.

High efficiency furnaces are now required by law

Effective December 30, 2009 the Province of Manitoba enacted legislation controlling the sale and lease of gas and propane heating equipment. Visit www.greenmanitoba.ca (click on the energy tab) for more information on this regulation.

Size of existing electrical service

Your electrical system may need to be upgraded if you want it to carry a heating load.

Depending on the capacity of the electrical appliances and equipment currently installed, and the size of your home, the Manitoba Electrical Code will allow a maximum of 8 to 10 kilowatts of electric heating on a standard 100-amp service. Most homes will need more than this.

Increasing the size of an electrical service usually involves changing your electrical panel or installing an additional one. An electrician should perform an electrical code load calcula-tion to advise whether your existing service is adequate to serve the heating equipment required to heat your home.

Other gas appliances

If you have other appliances in your home like a range, clothes dryer, fireplace, or swimming pool heater, switching to an all-electric system may be quite costly.

Flue Gas Venting

When natural gas is burned, flue gases are produced which primarily contain carbon dioxide and water vapour which are not harmful to people. However, flue gases can also contain trace amounts of carbon monoxide and other gases that can present a health hazard. High-efficiency natural gas furnaces will not use the existing chimney to vent (remove) flue gases from the home. Instead they will be vented via approved plastic piping through the home's side wall or roof.

If you have a standard natural gas water heater, the Manitoba Gas Notices allow it to continue to use the existing chimney if it is in good condition and meets the requirements of the Code Authority Having Jurisdiction (Manitoba Dept. of Labour). Your heating contractor should inform you if the chimney has corroded or does not meet the code requirements. Generally, installing a new approved smaller diameter chimney liner may meet the requirements.

Issues that can arise once the natural gas water heater vents alone on the old chimney include: flue gases condensing in the chimney, or flue gas spillage into the home. If these venting problems occur, you may need to upgrade you venting system or have other work performed to rectify them. If the upgrades are costly, other options to consider are replacing the conventional heater with a side-wall vented gas water heater or an electric water heater.

Reduced chimney ventilation

Converting to electric heat or to a high-efficiency gas furnace will reduce the uncontrolled ventilation provided by the chimney. The uncontrolled chimney ventilation will be completely eliminated if you also replace your conventional gas water heater and either remove or cap off the chimney.

With a conventional gas furnace, warm moist air continuously exits the house through the chimney. This draws cold and dry replacement air into the house through cracks in walls and around windows and doors. This uncontrolled ventilation dehumidifies your home in winter, but consumes heating energy.

Reducing or eliminating this chimney ventilation can save energy but may also increase humidity levels and change the way that air leaks into and out of your home. Homes usually become slightly more positively pressurized.

The increase in humidity and change in air leakage patterns may cause increased condensation/icing: on interior surfaces of well-sealed windows, and anywhere warm moist air leaks out of the home such as electrical outlets, between the panes of poorly sealed windows, on door seals, in door lock mechanisms and around chimney and plumbing stacks. A very small percentage of homeowners have reported experiencing some of these issues.

There is not one solution that works in every home and for every issue. Here are some of the measures that individually or in combina-tion can minimize or eliminate the effects of reduced chimney ventilation:

- improved weatherstripping and caulking on doors and windows and other areas of air leakage (but not on storm doors)
- seasonal window insulator kits (clear heat shrink poly over inside windows and frames)
- improved windows (preferably triple pane)
- a ventilation system which may consist of:
  - exhaust fan(s)
  - exhaust fan(s) combined with a fresh air intake
  - heat recovery ventilator (HRV)

Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect May 1, 2012

3

Carbon monoxide safety

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The building code now requires permanently mounted carbon monoxide detectors in all new homes with fuel burning appliances or attached garages.

For further details, contact us for a copy of our brochure on "Carbon monoxide safety — Because your family comes first!"

What is the payback?

Determining how many years it will take for a new heating system to pay for itself may help you reach a decision.

Determine the potential savings

Subtract the annual cost of the new heating system you are considering from the annual cost of your current heating system (check the charts).

The difference is approximately what you can expect to save each year, at current energy rates.

Determine the costs of the new system

Determine how much it will cost to buy and install the new system, along with any other adjustments required. Get quotations from three reputable contractors.

Factor in the cost of financing, if necessary.

Determine the payback

Divide the estimated cost of switching your system, by the estimated savings.

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Explanation of technical information in the charts

- Typical annual home heating requirement (output) of 60 Gigajoules is based on Manitoba Hydro's system average for natural gas heated homes.
- Water heating usage is based on Manitoba Hydro's average electric and natural gas water heating household of 2.4 people consuming about 140 litres per day that are heated up an average temperature rise of 50 C.
- The Electric water heating assisted by geothermal desuperheater option is based on Manitoba Hydro's field monitoring of nine homes with geothermal heating and desuperheaters where 80 per cent of the average water heating load was provided by the electric heating elements of the water tank and 20 per cent by the desuperheater.
- The cost of heating with propane includes a propane tank rental or lease charge of $151 per year for a typical 500 US gallon tank. See table below. This charge may not apply to all customers and may vary.
- The cost of space heating with natural gas includes a basic monthly charge of $14 ($168 per year).
- SE (seasonal efficiency) is defined as the total heat output delivered by the furnace during one heating season as a percentage of the total energy input to the system. SE takes into consideration not only normal operating losses but also the fact that most furnaces rarely run long enough to reach their steady-state efficiency temperature, particularly during milder weather at the beginning and end of the heating season.
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  The SCOP of a geothermal heat pump system typically ranges from 2.0 to 3.0. For reference, the SCOP of an electric baseboard heater is 1.0. The SCOP rating accounts for cycling losses, circulating fan and pump energy and auxiliary electric heating loads which are not included in the manufacturer's COP rating of the heat pump "unit". The overall system SCOP will therefore always be significantly lower than the unit COP.

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- Note that the natural gas energy price reflected in the charts is a bundled price that includes primary and supplemental gas, and transportation and distribution charges. For reference, one of the major components of the bundled price is the price of Primary Gas, at $0.0880 per cubic metre. Primary Gas currently comprises 98 per cent of the gas supplied (supplemental gas is 2 per cent.)
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ENERGY RATES — in effect May 1, 2012

	Commodity charge	Heating value	
Natural gas	$0.2220/cubic metre	35,310	Btu/cubic metre
Electricity	$0.0677/kilowatt-hour	3,413	Btu/kilowatt-hour
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Propane	$0.492/litre	24,200	Btu/litre

Manitoba Hydro
POWER SMART*

Typical space & water heating costs

1

Average single family residence at rates in effect August 1, 2012

Wondering about your energy options for heating?

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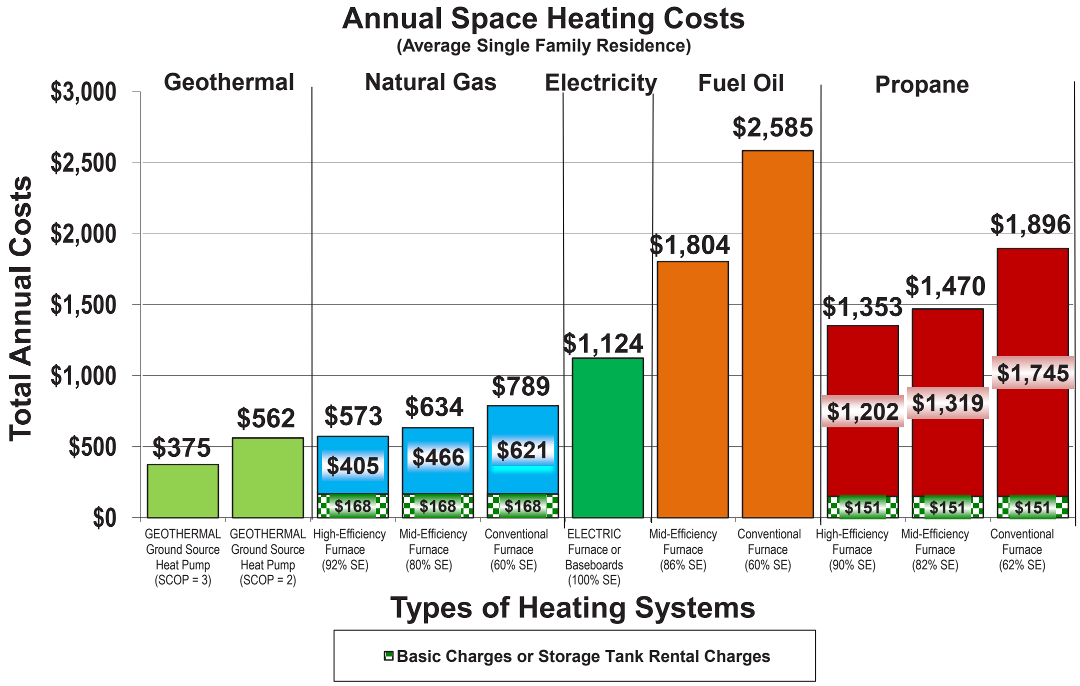

Energy rates

Natural gas:
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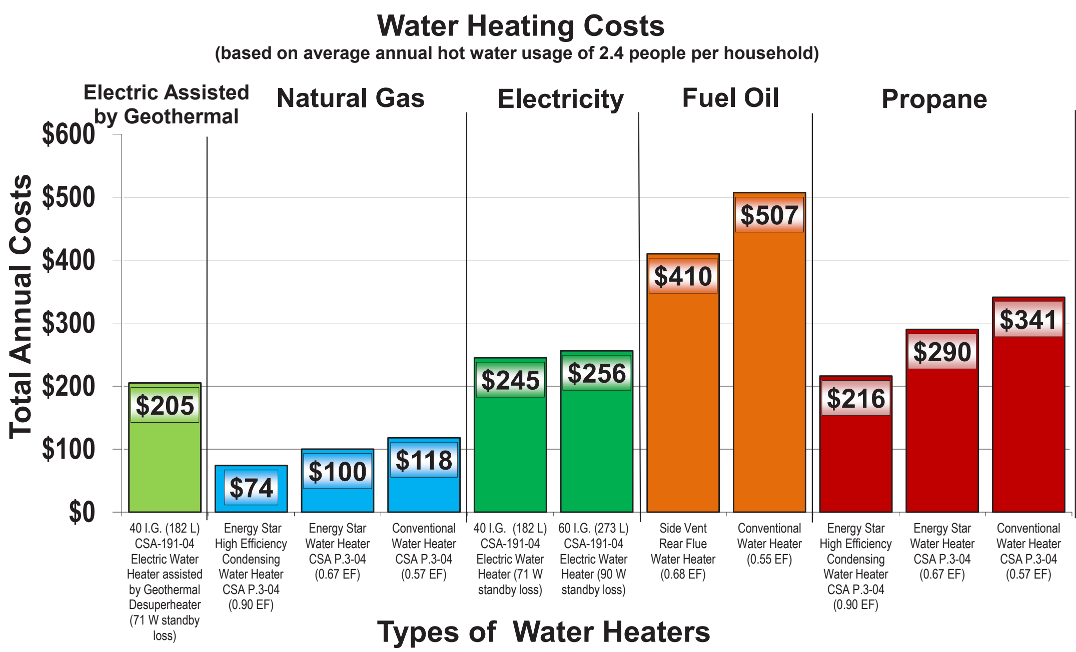

Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect August 1, 2012

2

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Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect August 1, 2012

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ENERGY RATES — in effect August 1, 2012

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Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect November 1, 2012

1

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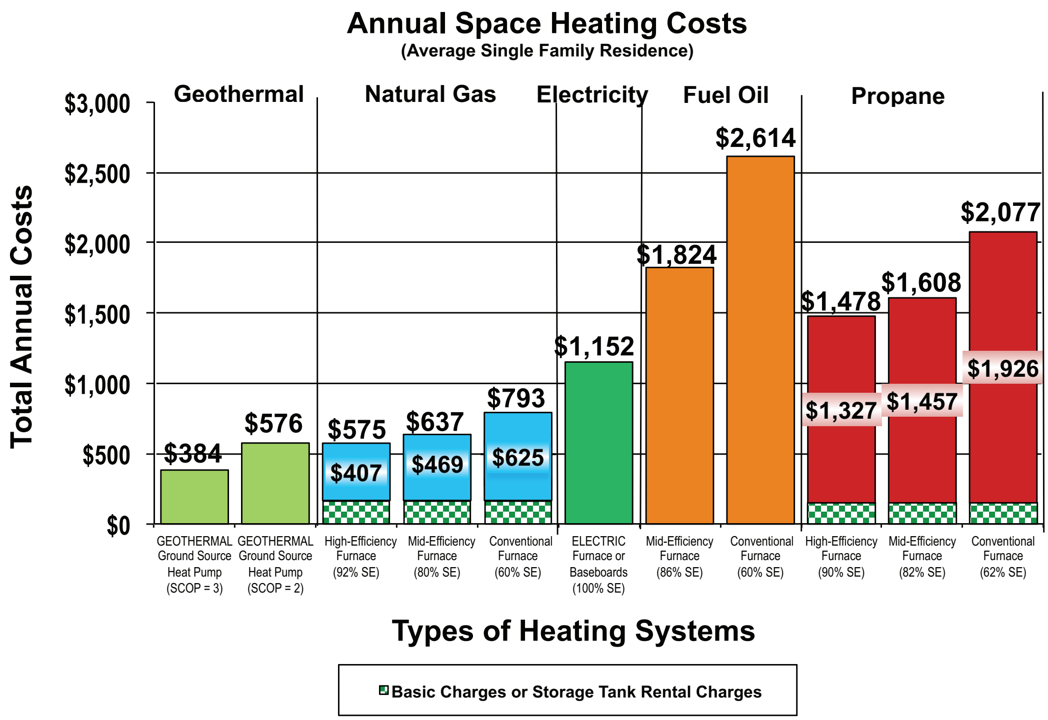

Energy rates

Natural gas:
$0.2336/cubic metre

Electricity:
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Propane:
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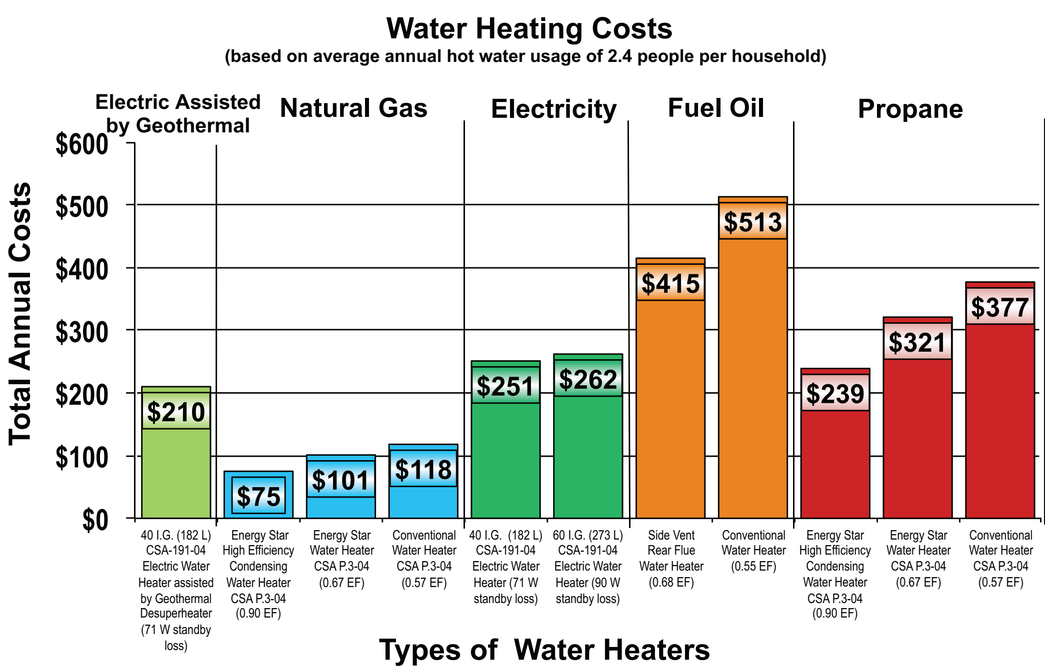

Manitoba Hydro POWER SMART*

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  The SCOP of a geothermal system can vary significantly and is highly dependent on the quality of the system design, installation, commissioning and ongoing maintenance practices.
- Note that the natural gas energy price reflected in the charts is a bundled price that includes primary and supplemental gas, and transportation and distribution charges. For reference, one of the major components of the bundled price is the price of Primary Gas, at 0.0967 per cubic metre. Primary Gas currently comprises 90 per cent of the gas supplied (supplemental gas is 10 per cent.)
- Taxes are not included in these calculations and costs.

ENERGY RATES — in effect November 1, 2012

	Commodity charge	Heating value	
Natural gas	$0.2336/cubic metre	35,310	Btu/cubic metre
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Propane	$0.510/litre	24,200	Btu/litre

Manitoba Hydro
POWER SMART*

Typical space & water heating costs

1

Average single family residence at rates in effect February 1, 2013

Wondering about your energy options for heating?

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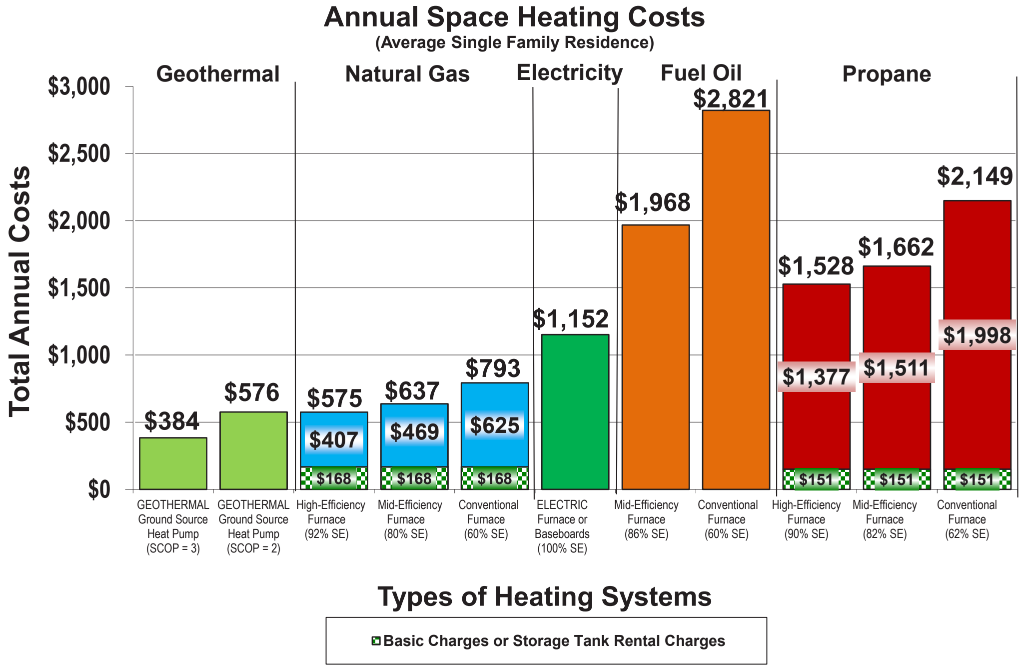

Energy rates

Natural gas:
$0.2336/cubic metre

Electricity:
$0.0694/kilowatt-hour

Fuel oil:
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Propane:
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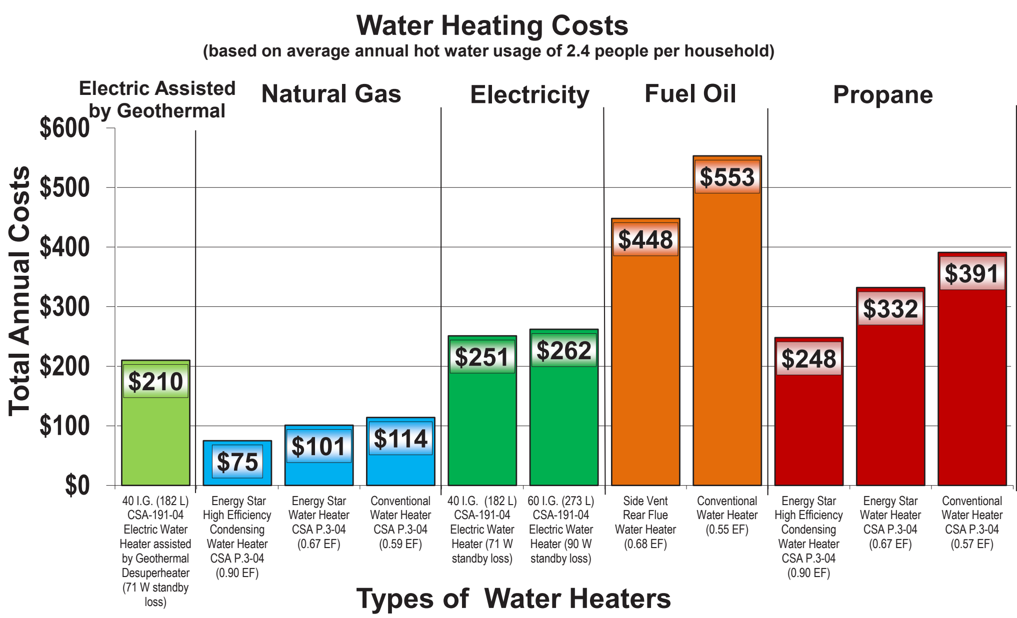

Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect February 1, 2013

2

Weigh your options

The home heating costs shown in the chart are based on the amount of gas used to heat the average natural gas-heated home served by Manitoba Hydro. This average home is about 1,200 square feet and uses a mid-efficiency furnace and conventional gas water heater. Your heating costs may differ due to a variety of factors, such as weather, heating equipment, insulation levels, air tightness and lifestyle. Water heating costs are based on typical usage of the average Manitoba household of 2.4 people.

Annual cost estimates

The charts present annual costs as if all energy rates remained fixed for the coming year at rates in effect on February 1, 2013.

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Key points if you are thinking of converting

Is it economically feasible?

Note that the costs of switching to another system to heat your home and hot water may be economically feasible only if your current system is at or near the end of its useful life, or if you are building a new home. Be sure to obtain quotations from at least three reputable heating contractors before you make your decision.

Conventional furnaces no longer manufactured

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High efficiency furnaces are now required by law

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Size of existing electrical service

Your electrical system may need to be upgraded if you want it to carry a heating load.

Depending on the capacity of the electrical appliances and equipment currently installed, and the size of your home, the Manitoba Electrical Code will allow a maximum of 8 to 10 kilowatts of electric heating on a standard 100-amp service. Most homes will need more than this.

Increasing the size of an electrical service usually involves changing your electrical panel or installing an additional one. An electrician should perform an electrical code load calculation to advise whether your existing service is adequate to serve the heating equipment required to heat your home.

Other gas appliances

If you have other appliances in your home like a range, clothes dryer, fireplace, or swimming pool heater, switching to an all-electric system may be quite costly.

Flue Gas Venting

When natural gas is burned, flue gases are produced which primarily contain carbon dioxide and water vapour which are not harmful to people. However, flue gases can also contain trace amounts of carbon monoxide and other gases that can present a health hazard. High-efficiency natural gas furnaces will not use the existing chimney to vent (remove) flue gases from the home. Instead they will be vented via approved plastic piping through the home's side wall or roof.

If you have a standard natural gas water heater, the Manitoba Gas Notices allow it to continue to use the existing chimney if it is in good condition and meets the requirements of the Code Authority Having Jurisdiction (Manitoba Dept. of Labour). Your heating contractor should inform you if the chimney has corroded or does not meet the code requirements. Generally, installing a new approved smaller diameter chimney liner may meet the requirements.

Issues that can arise once the natural gas water heater vents alone on the old chimney include: flue gases condensing in the chimney, or flue gas spillage into the home. If these venting problems occur, you may need to upgrade your venting system or have other work performed to rectify them. If the upgrades are costly, other options to consider are replacing the conventional heater with a side-wall vented gas water heater or an electric water heater.

Reduced chimney ventilation

Converting to electric heat or to a high-efficiency gas furnace will reduce the uncontrolled ventilation provided by the chimney. The uncontrolled chimney ventilation will be completely eliminated if you also replace your conventional gas water heater and either remove or cap off the chimney.

With a conventional gas furnace, warm moist air continuously exits the house through the chimney. This draws cold and dry replacement air into the house through cracks in walls and around windows and doors. This uncontrolled ventilation dehumidifies your home in winter, but consumes heating energy.

Reducing or eliminating this chimney ventilation can save energy but may also increase humidity levels and change the way that air leaks into and out of your home. Homes usually become slightly more positively pressurized.

The increase in humidity and change in air leakage patterns may cause increased condensation/icing: on interior surfaces of well-sealed windows, and anywhere warm moist air leaks out of the home such as electrical outlets, between the panes of poorly sealed windows, on door seals, in door lock mechanisms and around chimney and plumbing stacks. A very small percentage of homeowners have reported experiencing some of these issues.

There is not one solution that works in every home and for every issue. Here are some of the measures that individually or in combination can minimize or eliminate the effects of reduced chimney ventilation:

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- seasonal window insulator kits (clear heat shrink poly over inside windows and frames)
- improved windows (preferably triple pane)
- a ventilation system which may consist of:
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  - exhaust fan(s) combined with a fresh air intake
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Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect February 1, 2013

3

Carbon monoxide safety

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The building code now requires permanently mounted carbon monoxide detectors in all new homes with fuel burning appliances or attached garages.

For further details, contact us for a copy of our brochure on "Carbon monoxide safety — Because your family comes first!"

What is the payback?

Determining how many years it will take for a new heating system to pay for itself may help you reach a decision.

Determine the potential savings

Subtract the annual cost of the new heating system you are considering from the annual cost of your current heating system (check the charts).

The difference is approximately what you can expect to save each year, at current energy rates.

Determine the costs of the new system

Determine how much it will cost to buy and install the new system, along with any other adjustments required. Get quotations from three reputable contractors.

Factor in the cost of financing, if necessary.

Determine the payback

Divide the estimated cost of switching your system, by the estimated savings.

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Explanation of technical information in the charts

- Typical annual home heating requirement (output) of 60 Gigajoules is based on Manitoba Hydro's system average for natural gas heated homes.
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- The Electric water heating assisted by geothermal desuperheater option is based on Manitoba Hydro's field monitoring of nine homes with geothermal heating and desuperheaters where 80 per cent of the average water heating load was provided by the electric heating elements of the water tank and 20 per cent by the desuperheater.
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Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect May 1, 2013

1

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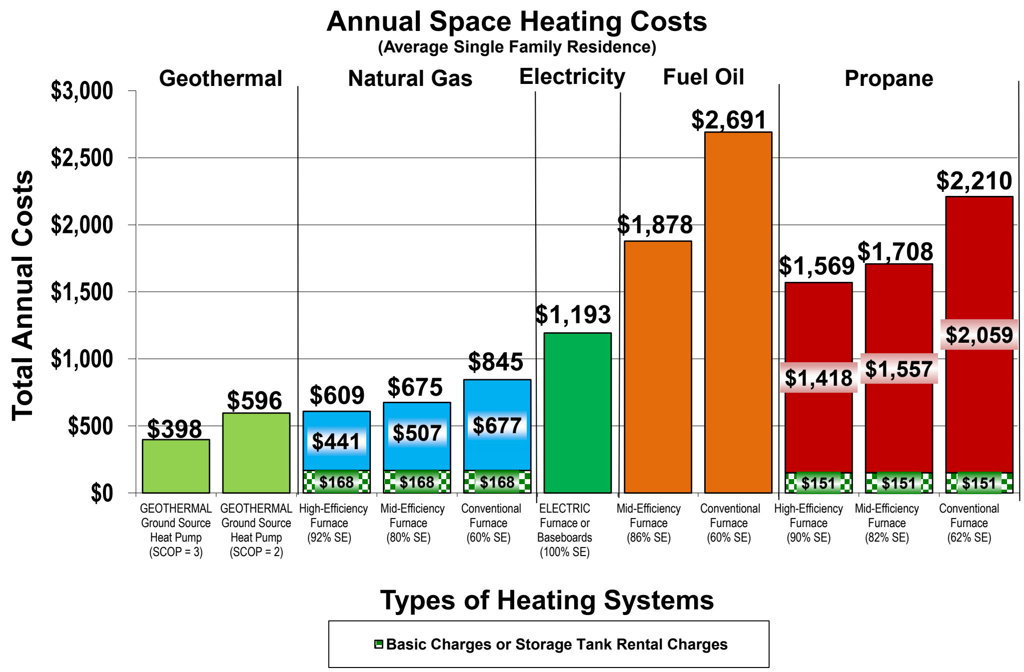

Energy rates

Natural gas:
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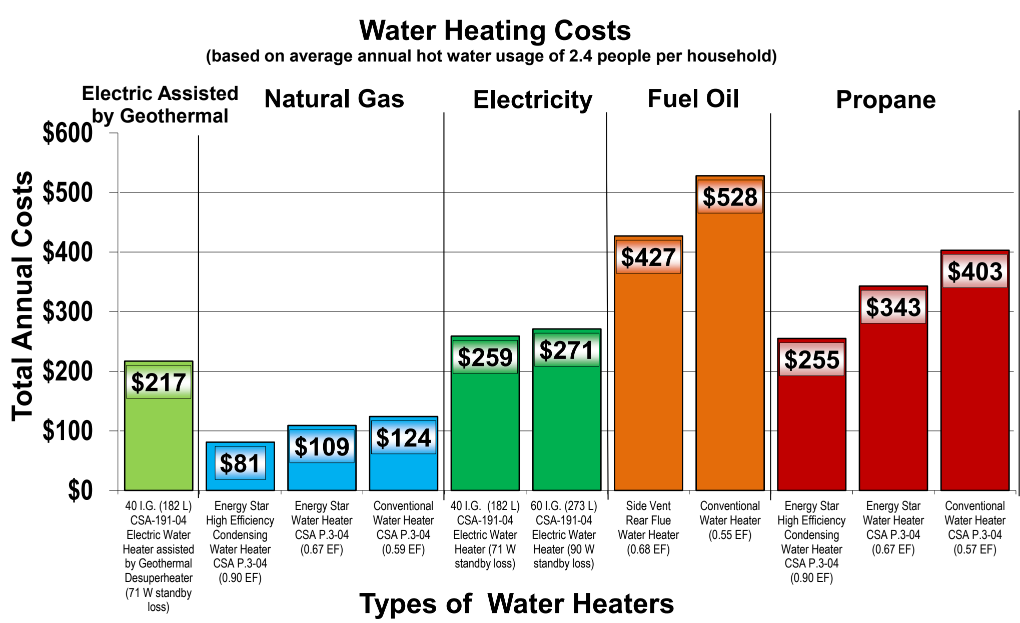

Manitoba Hydro
POWER SMART*

Typical space & water heating costs

2

Average single family residence at rates in effect May 1, 2013

Weigh your options

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Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect May 1, 2013

3

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Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect August 1, 2013

1

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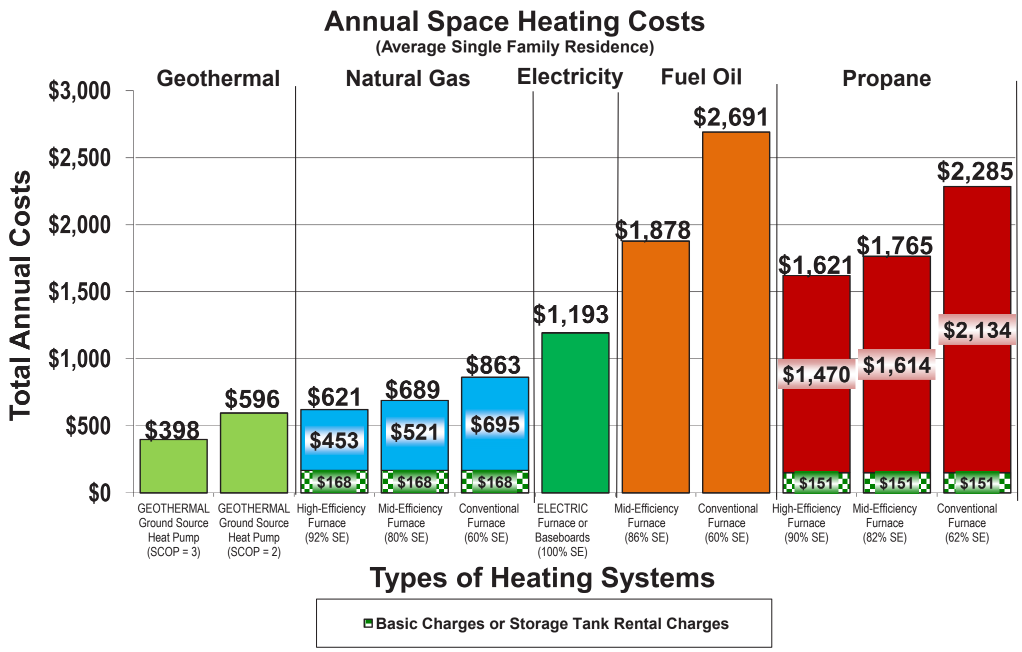

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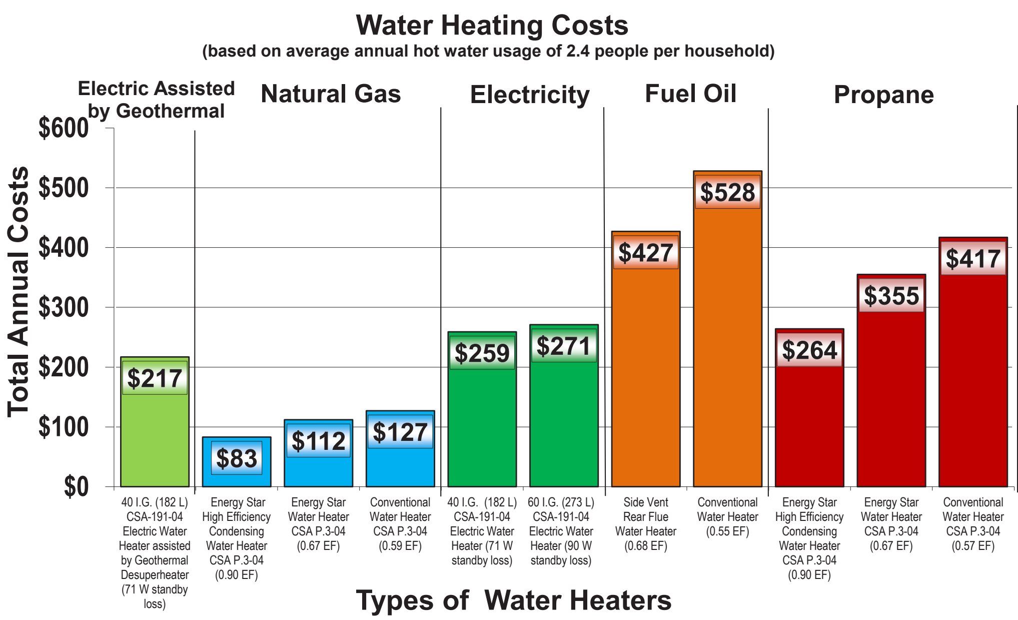

Manitoba Hydro
POWER SMART*

Typical space & water heating costs

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2

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Reduced chimney ventilation

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With a conventional gas furnace, warm moist air continuously exits the house through the chimney. This draws cold and dry replacement air into the house through cracks in walls and around windows and doors. This uncontrolled ventilation dehumidifies your home in winter, but consumes heating energy.

Reducing or eliminating this chimney ventilation can save energy but may also increase humidity levels and change the way that air leaks into and out of your home. Homes usually become slightly more positively pressurized.

The increase in humidity and change in air leakage patterns may cause increased condensation/icing: on interior surfaces of well-sealed windows, and anywhere warm moist air leaks out of the home such as electrical outlets, between the panes of poorly sealed windows, on door seals, in door lock mechanisms and around chimney and plumbing stacks. A very small percentage of homeowners have reported experiencing some of these issues.

There is not one solution that works in every home and for every issue. Here are some of the measures that individually or in combination can minimize or eliminate the effects of reduced chimney ventilation:

- improved weatherstripping and caulking on doors and windows and other areas of air leakage (but not on storm doors)
- seasonal window insulator kits (clear heat shrink poly over inside windows and frames)
- improved windows (preferably triple pane)
- a ventilation system which may consist of:
  - exhaust fan(s)
  - exhaust fan(s) combined with a fresh air intake
  - heat recovery ventilator (HRV)

Manitoba Hydro
POWER SMART*

Typical space & water heating costs

3

Average single family residence at rates in effect August 1, 2013

Carbon monoxide safety

If you are burning heating oil, diesel, propane, kerosene, natural gas, wood, or coal in your home, or if you have an attached garage, we recommend that you install at least one carbon monoxide detector in your home.

The building code now requires permanently mounted carbon monoxide detectors in all new homes with fuel burning appliances or attached garages.

For further details, contact us for a copy of our brochure on "Carbon monoxide safety — Because your family comes first!"

What is the payback?

Determining how many years it will take for a new heating system to pay for itself may help you reach a decision.

Determine the potential savings

Subtract the annual cost of the new heating system you are considering from the annual cost of your current heating system (check the charts).

The difference is approximately what you can expect to save each year, at current energy rates.

Determine the costs of the new system

Determine how much it will cost to buy and install the new system, along with any other adjustments required. Get quotations from three reputable contractors.

Factor in the cost of financing, if necessary.

Determine the payback

Divide the estimated cost of switching your system, by the estimated savings.

The result is the number of years it will take for the new system to pay for itself.

Explanation of technical information in the charts

- Typical annual home heating requirement (output) of 60 Gigajoules is based on Manitoba Hydro's system average for natural gas heated homes.
- Water heating usage is based on Manitoba Hydro's average electric and natural gas water heating household of 2.4 people consuming about 140 litres per day that are heated up an average temperature rise of 50 C.
- The Electric water heating assisted by geothermal desuperheater option is based on Manitoba Hydro's field monitoring of nine homes with geothermal heating and desuperheaters where 80 per cent of the average water heating load was provided by the electric heating elements of the water tank and 20 per cent by the desuperheater.
- The cost of heating with propane includes a propane tank rental or lease charge of $151 per year for a typical 500 US gallon tank. See table below. This charge may not apply to all customers and may vary.
- The cost of space heating with natural gas includes a basic monthly charge of $14 ($168 per year).
- SE (seasonal efficiency) is defined as the total heat output delivered by the furnace during one heating season as a percentage of the total energy input to the system. SE takes into consideration not only normal operating losses but also the fact that most furnaces rarely run long enough to reach their steady-state efficiency temperature, particularly during milder weather at the beginning and end of the heating season.
- Energy Factor (EF) is an overall efficiency rating of the water heater. The higher the EF, the more efficient the model. Electric water heaters are required to have maximum standby losses of 71 watts for a 40 gallon and 90 Watts for a 60 gallon.
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  SCOP is defined as the total heat output of the system during the heating season, divided by the total energy input to the system.

  The SCOP of a geothermal heat pump system typically ranges from 2.0 to 3.0. For reference, the SCOP of an electric baseboard heater is 1.0. The SCOP rating accounts for cycling losses, circulating fan and pump energy and auxiliary electric heating loads which are not included in the manufacturer's COP rating of the heat pump "unit". The overall system SCOP will therefore always be significantly lower than the unit COP.

  The SCOP of a geothermal system can vary significantly and is highly dependent on the quality of the system design, installation, commissioning and ongoing maintenance practices.
- Note that the natural gas energy price reflected in the charts is a bundled price that includes primary and supplemental gas, and transportation and distribution charges. For reference, one of the major components of the bundled price is the price of Primary Gas, at 0.1092 per cubic metre. Primary Gas currently comprises 71 per cent of the gas supplied (supplemental gas is 29 per cent.)
- Taxes are not included in these calculations and costs.

ENERGY RATES — in effect August 1, 2013

	Commodity charge	Heating value	
Natural gas	$0.2597/cubic metre	35,310	Btu/cubic metre
Electricity	$0.07183/kilowatt-hour	3,413	Btu/kilowatt-hour
Fuel oil	$1.040/litre	36,500	Btu/litre
Propane	$0.565/litre	24,200	Btu/litre

Manitoba Hydro POWER SMART*

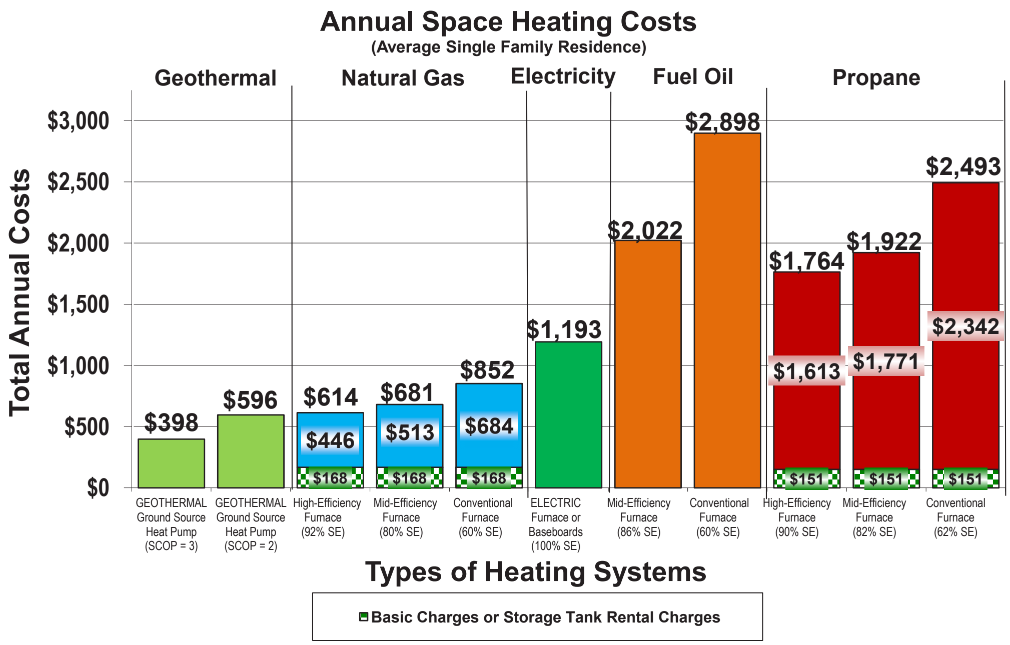
Typical space & water heating costs

Average single family residence at rates in effect November 1, 2013

1

Wondering about your energy options for heating?

1. Consult the charts to identify the costs of your current home heating and water heating systems.
2. Review the costs of other systems to see how your costs compare.
3. Consult the accompanying notes for guidance if you are thinking of switching systems or building a new home.



Energy rates

Natural gas:
$0.2558/cubic metre

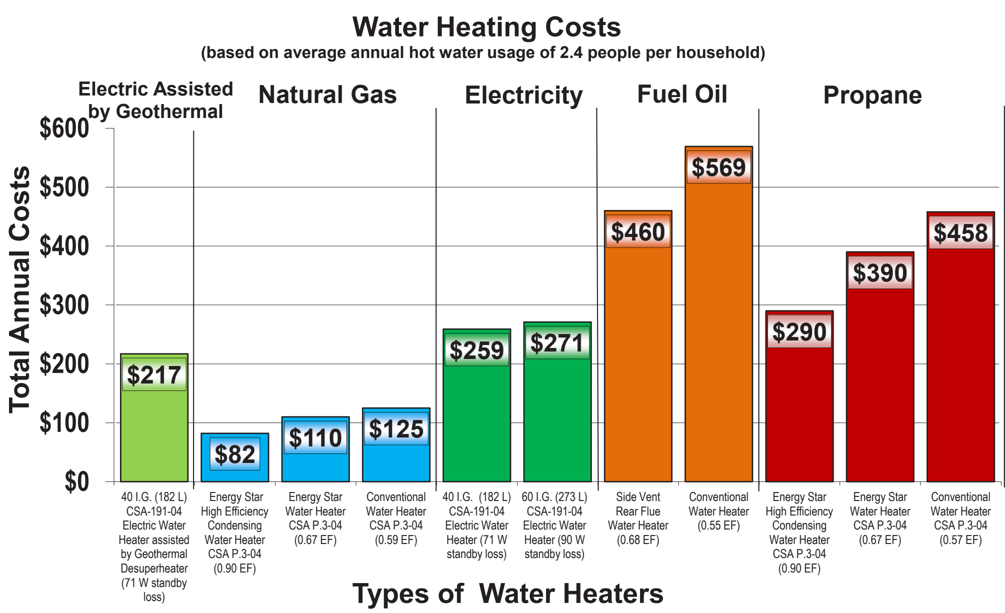
Electricity:
$0.07183/kilowatt-hour

Fuel oil:
$1.12/litre

Propane:
$0.62/litre

Basic monthly charge for natural gas is **$14** (**$168** per year)

Annual propane tank rental: **$151**



Manitoba Hydro
POWER SMART*

Typical space & water heating costs

2

Average single family residence at rates in effect November 1, 2013

Weigh your options

The home heating costs shown in the chart are based on the amount of gas used to heat the average natural gas-heated home served by Manitoba Hydro. This average home is about 1,200 square feet and uses a mid-efficiency furnace and conventional gas water heater. Your heating costs may differ due to a variety of factors, such as weather, heating equipment, insulation levels, air tightness and lifestyle. Water heating costs are based on typical usage of the average Manitoba household of 2.4 people.

Annual cost estimates

The charts present annual costs as if all energy rates remained fixed for the coming year at rates in effect on November 1, 2013.

Your actual annual costs will vary, since natural gas rates change four times a year, while propane and oil rates can change weekly. Note that Primary Gas represents the bulk of the gas used. With Manitoba Hydro's Quarterly Rate Service, the price you pay for Primary Gas is the same price we pay for the gas in the marketplace. This rate changes every 3 months and is currently $0.1142 per cubic metre. If you buy Primary Gas on a Fixed Rate Service contract from Manitoba Hydro or a Gas Broker, you will continue to pay Manitoba Hydro for Supplemental Gas as well as transportation and distribution charges. The figure of 0.2558 per cubic metre of natural gas that we've used in the charts is known as a "re-bundled" effective rate. It includes charges for Primary and Supplemental gas, as well as for transportation and distribution of the gas on Manitoba Hydro's Quarterly Rate Service.

Key points if you are thinking of converting

Is it economically feasible?

Note that the costs of switching to another system to heat your home and hot water may be economically feasible only if your current system is at or near the end of its useful life, or if you are building a new home. Be sure to obtain quotations from at least three reputable heating contractors before you make your decision.

Conventional furnaces no longer manufactured

The space heating chart includes conventional natural gas, fuel oil, and propane furnaces. These conventional furnaces have not been manufactured since 1992, but many are still in operation.

High efficiency furnaces are now required by law

Effective December 30, 2009 the Province of Manitoba enacted legislation controlling the sale and lease of gas and propane heating equipment. Visit www.greenmanitoba.ca (click on the energy tab) for more information on this regulation.

Size of existing electrical service

Your electrical system may need to be upgraded if you want it to carry a heating load.

Depending on the capacity of the electrical appliances and equipment currently installed, and the size of your home, the Manitoba Electrical Code will allow a maximum of 8 to 10 kilowatts of electric heating on a standard 100-amp service. Most homes will need more than this.

Increasing the size of an electrical service usually involves changing your electrical panel or installing an additional one. An electrician should perform an electrical code load calculation to advise whether your existing service is adequate to serve the heating equipment required to heat your home.

Other gas appliances

If you have other appliances in your home like a range, clothes dryer, fireplace, or swimming pool heater, switching to an all-electric system may be quite costly.

Flue Gas Venting

When natural gas is burned, flue gases are produced which primarily contain carbon dioxide and water vapour which are not harmful to people. However, flue gases can also contain trace amounts of carbon monoxide and other gases that can present a health hazard. High-efficiency natural gas furnaces will not use the existing chimney to vent (remove) flue gases from the home. Instead they will be vented via approved plastic piping through the home's side wall or roof.

If you have a standard natural gas water heater, the Manitoba Gas Notices allow it to continue to use the existing chimney if it is in good condition and meets the requirements of the Code Authority Having Jurisdiction (Manitoba Dept. of Labour). Your heating contractor should inform you if the chimney has corroded or does not meet the code requirements. Generally, installing a new approved smaller diameter chimney liner may meet the requirements.

Issues that can arise once the natural gas water heater vents alone on the old chimney include: flue gases condensing in the chimney, or flue gas spillage into the home. If these venting problems occur, you may need to upgrade your venting system or have other work performed to rectify them. If the upgrades are costly, other options to consider are replacing the conventional heater with a side-wall vented gas water heater or an electric water heater.

Reduced chimney ventilation

Converting to electric heat or to a high-efficiency gas furnace will reduce the uncontrolled ventilation provided by the chimney. The uncontrolled chimney ventilation will be completely eliminated if you also replace your conventional gas water heater and either remove or cap off the chimney.

With a conventional gas furnace, warm moist air continuously exits the house through the chimney. This draws cold and dry replacement air into the house through cracks in walls and around windows and doors. This uncontrolled ventilation dehumidifies your home in winter, but consumes heating energy.

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The increase in humidity and change in air leakage patterns may cause increased condensation/icing: on interior surfaces of well-sealed windows, and anywhere warm moist air leaks out of the home such as electrical outlets, between the panes of poorly sealed windows, on door seals, in door lock mechanisms and around chimney and plumbing stacks. A very small percentage of homeowners have reported experiencing some of these issues.

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Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect November 1, 2013

3

Carbon monoxide safety

If you are burning heating oil, diesel, propane, kerosene, natural gas, wood, or coal in your home, or if you have an attached garage, we recommend that you install at least one carbon monoxide detector in your home.

The building code now requires permanently mounted carbon monoxide detectors in all new homes with fuel burning appliances or attached garages.

For further details, contact us for a copy of our brochure on "Carbon monoxide safety — Because your family comes first!"

What is the payback?

Determining how many years it will take for a new heating system to pay for itself may help you reach a decision.

Determine the potential savings

Subtract the annual cost of the new heating system you are considering from the annual cost of your current heating system (check the charts).

The difference is approximately what you can expect to save each year, at current energy rates.

Determine the costs of the new system

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Divide the estimated cost of switching your system, by the estimated savings.

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Explanation of technical information in the charts

- Typical annual home heating requirement (output) of 60 Gigajoules is based on Manitoba Hydro's system average for natural gas heated homes.
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  The SCOP of a geothermal system can vary significantly and is highly dependent on the quality of the system design, installation, commissioning and ongoing maintenance practices.
- Note that the natural gas energy price reflected in the charts is a bundled price that includes primary and supplemental gas, and transportation and distribution charges. For reference, one of the major components of the bundled price is the price of Primary Gas, at 0.1142 per cubic metre. Primary Gas currently comprises 87 per cent of the gas supplied (supplemental gas is 13 per cent.)
- Taxes are not included in these calculations and costs.

ENERGY RATES — in effect November 1, 2013

	Commodity charge	Heating value	
Natural gas	$0.2558/cubic metre	35,310	Btu/cubic metre
Electricity	$0.07183/kilowatt-hour	3,413	Btu/kilowatt-hour
Fuel oil	$1.12/litre	36,500	Btu/litre
Propane	$0.62/litre	24,200	Btu/litre

Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect February 1, 2014

1

Wondering about your energy options for heating?

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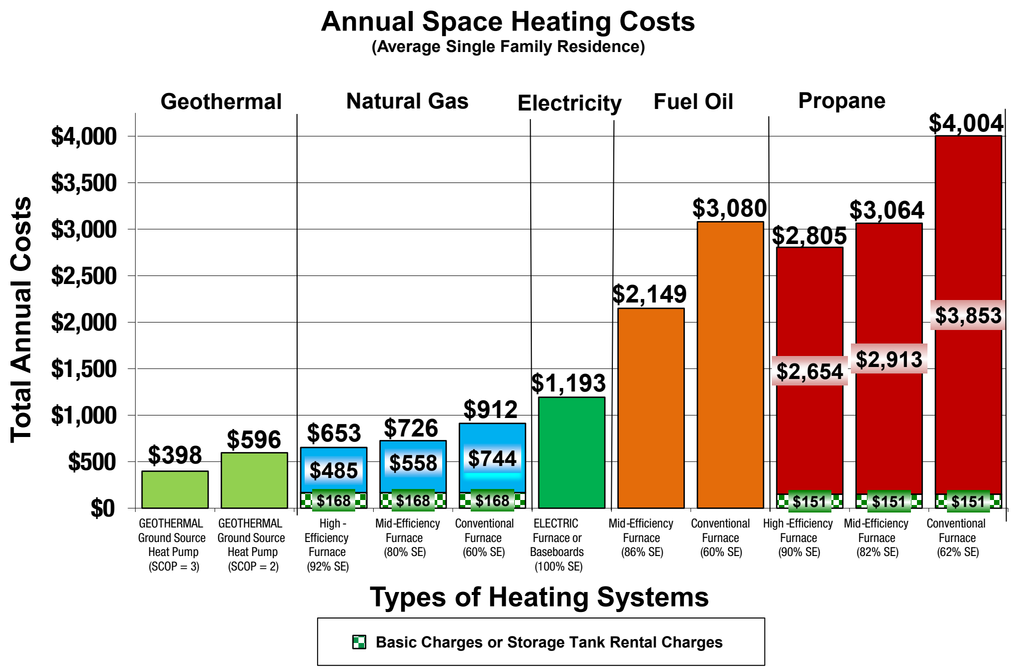


Energy rates

Natural gas:
$0.2780/cubic metre

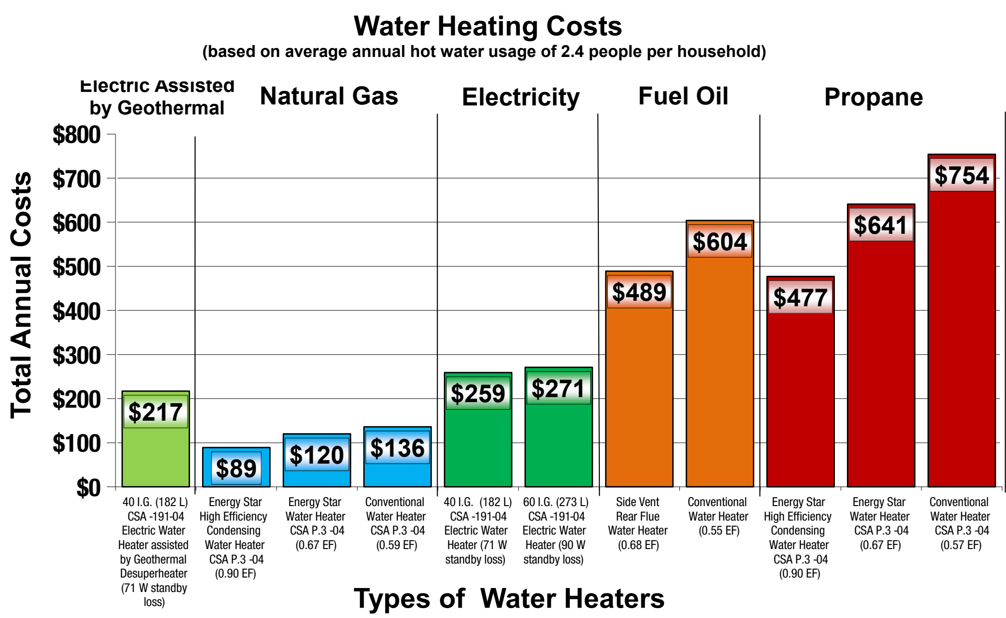
Electricity:
$0.07183/kilowatt-hour

Fuel oil:
$**1.19**/litre

Propane:
$1.02/litre

Basic monthly charge for natural gas is **$14** (**$168** per year)

Annual propane tank rental: **$151**



Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect February 1, 2014

2

Weigh your options

The home heating costs shown in the chart are based on the amount of gas used to heat the average natural gas-heated home served by Manitoba Hydro. This average home is about 1,200 square feet and uses a mid-efficiency furnace and conventional gas water heater. Your heating costs may differ due to a variety of factors, such as weather, heating equipment, insulation levels, air tightness and lifestyle. Water heating costs are based on typical usage of the average Manitoba household of 2.4 people.

Annual cost estimates

The charts present annual costs as if all energy rates remained fixed for the coming year at rates in effect on February 1, 2014.

Your actual annual costs will vary, since natural gas rates change four times a year, while propane and oil rates can change weekly. Note that Primary Gas represents the bulk of the gas used. With Manitoba Hydro's Quarterly Rate Service, the price you pay for Primary Gas is the same price we pay for the gas in the marketplace. This rate changes every 3 months and is currently $0.1382 per cubic metre. If you buy Primary Gas on a Fixed Rate Service contract from Manitoba Hydro or a Gas Broker, you will continue to pay Manitoba Hydro for Supplemental Gas as well as transportation and distribution charges. The figure of 0.2780 per cubic metre of natural gas that we've used in the charts is known as a "re-bundled" effective rate. It includes charges for Primary and Supplemental gas, as well as for transportation and distribution of the gas on Manitoba Hydro's Quarterly Rate Service.

Key points if you are thinking of converting

Is it economically feasible?

Note that the costs of switching to another system to heat your home and hot water may be economically feasible only if your current system is at or near the end of its useful life, or if you are building a new home. Be sure to obtain quotations from at least three reputable heating contractors before you make your decision.

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Size of existing electrical service

Your electrical system may need to be upgraded if you want it to carry a heating load.

Depending on the capacity of the electrical appliances and equipment currently installed, and the size of your home, the Manitoba Electrical Code will allow a maximum of 8 to 10 kilowatts of electric heating on a standard 100-amp service. Most homes will need more than this.

Increasing the size of an electrical service usually involves changing your electrical panel or installing an additional one. An electrician should perform an electrical code load calculation to advise whether your existing service is adequate to serve the heating equipment required to heat your home.

Other gas appliances

If you have other appliances in your home like a range, clothes dryer, fireplace, or swimming pool heater, switching to an all-electric system may be quite costly.

Flue Gas Venting

When natural gas is burned, flue gases are produced which primarily contain carbon dioxide and water vapour which are not harmful to people. However, flue gases can also contain trace amounts of carbon monoxide and other gases that can present a health hazard. High-efficiency natural gas furnaces will not use the existing chimney to vent (remove) flue gases from the home. Instead they will be vented via approved plastic piping through the home's side wall or roof.

If you have a standard natural gas water heater, the Manitoba Gas Notices allow it to continue to use the existing chimney if it is in good condition and meets the requirements of the Code Authority Having Jurisdiction (Manitoba Dept. of Labour). Your heating contractor should inform you if the chimney has corroded or does not meet the code requirements. Generally, installing a new approved smaller diameter chimney liner may meet the requirements.

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Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect February 1, 2014

3

Carbon monoxide safety

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- Note that the natural gas energy price reflected in the charts is a bundled price that includes primary and supplemental gas, and transportation and distribution charges. For reference, one of the major components of the bundled price is the price of Primary Gas, at 0.1382 per cubic metre. Primary Gas currently comprises 81 per cent of the gas supplied (supplemental gas is 19 per cent.)
- Taxes are not included in these calculations and costs.

ENERGY RATES — in effect February 1, 2014

	Commodity charge	Heating value	
Natural gas	$0.2780/cubic metre	35,310	Btu/cubic metre
Electricity	$0.07183/kilowatt-hour	3,413	Btu/kilowatt-hour
Fuel oil	$1.19/litre	36,500	Btu/litre
Propane	$1.09/litre	24,200	Btu/litre

Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect May 1, 2014

1

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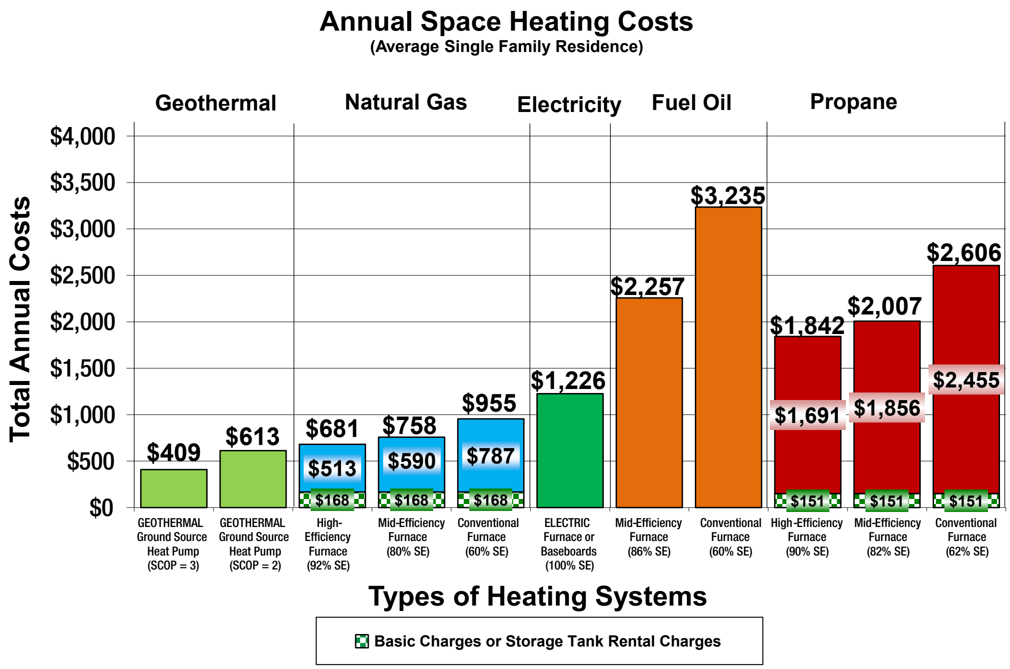


Energy rates

Natural gas:
$0.2941/cubic metre

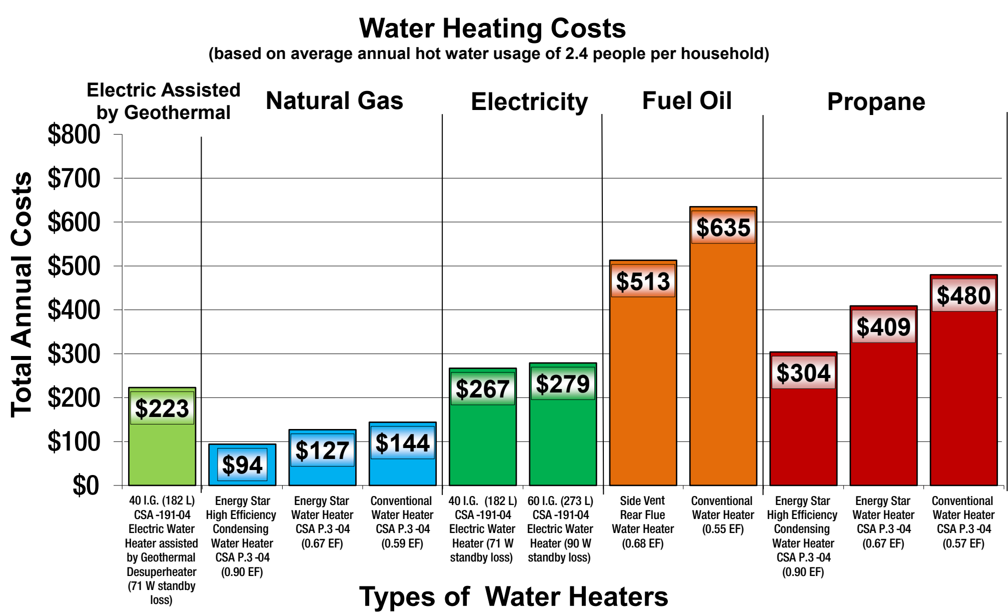
Electricity:
$0.07381/kilowatt-hour

Fuel oil:
$**1.25**/litre

Propane:
$.65/litre

Basic monthly charge for natural gas is **$14** (**$168** per year)

Annual propane tank rental: **$151**



Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect May 1, 2014

2

Weigh your options

The home heating costs shown in the chart are based on the amount of gas used to heat the average natural gas-heated home served by Manitoba Hydro. This average home is about 1,200 square feet and uses a mid-efficiency furnace and conventional gas water heater. Your heating costs may differ due to a variety of factors, such as weather, heating equipment, insulation levels, air tightness and lifestyle. Water heating costs are based on typical usage of the average Manitoba household of 2.4 people.

Annual cost estimates

The charts present annual costs as if all energy rates remained fixed for the coming year at rates in effect on May 1, 2014.

Your actual annual costs will vary, since natural gas rates change four times a year, while propane and oil rates can change weekly. Note that Primary Gas represents the bulk of the gas used. With Manitoba Hydro's Quarterly Rate Service, the price you pay for Primary Gas is the same price we pay for the gas in the marketplace. This rate changes every 3 months and is currently $0.1567 per cubic metre. If you buy Primary Gas on a Fixed Rate Service contract from Manitoba Hydro or a Gas Broker, you will continue to pay Manitoba Hydro for Supplemental Gas as well as transportation and distribution charges. The figure of 0.2941 per cubic metre of natural gas that we've used in the charts is known as a "re-bundled" effective rate. It includes charges for Primary and Supplemental gas, as well as for transportation and distribution of the gas on Manitoba Hydro's Quarterly Rate Service.

Key points if you are thinking of converting

Is it economically feasible?

Note that the costs of switching to another system to heat your home and hot water may be economically feasible only if your current system is at or near the end of its useful life, or if you are building a new home. Be sure to obtain quotations from at least three reputable heating contractors before you make your decision.

Conventional furnaces no longer manufactured

The space heating chart includes conventional natural gas, fuel oil, and propane furnaces. These conventional furnaces have not been manufactured since 1992, but many are still in operation.

High efficiency furnaces are now required by law

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Size of existing electrical service

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Depending on the capacity of the electrical appliances and equipment currently installed, and the size of your home, the Manitoba Electrical Code will allow a maximum of 8 to 10 kilowatts of electric heating on a standard 100-amp service. Most homes will need more than this.

Increasing the size of an electrical service usually involves changing your electrical panel or installing an additional one. An electrician should perform an electrical code load calculation to advise whether your existing service is adequate to serve the heating equipment required to heat your home.

Other gas appliances

If you have other appliances in your home like a range, clothes dryer, fireplace, or swimming pool heater, switching to an all-electric system may be quite costly.

Flue Gas Venting

When natural gas is burned, flue gases are produced which primarily contain carbon dioxide and water vapour which are not harmful to people. However, flue gases can also contain trace amounts of carbon monoxide and other gases that can present a health hazard. High-efficiency natural gas furnaces will not use the existing chimney to vent (remove) flue gases from the home. Instead they will be vented via approved plastic piping through the home's side wall or roof.

If you have a standard natural gas water heater, the Manitoba Gas Notices allow it to continue to use the existing chimney if it is in good condition and meets the requirements of the Code Authority Having Jurisdiction (Manitoba Dept. of Labour). Your heating contractor should inform you if the chimney has corroded or does not meet the code requirements. Generally, installing a new approved smaller diameter chimney liner may meet the requirements.

Issues that can arise once the natural gas water heater vents alone on the old chimney include: flue gases condensing in the chimney, or flue gas spillage into the home. If these venting problems occur, you may need to upgrade your venting system or have other work performed to rectify them. If the upgrades are costly, other options to consider are replacing the conventional heater with a side-wall vented gas water heater or an electric water heater.

Reduced chimney ventilation

Converting to electric heat or to a high-efficiency gas furnace will reduce the uncontrolled ventilation provided by the chimney. The uncontrolled chimney ventilation will be completely eliminated if you also replace your conventional gas water heater and either remove or cap off the chimney.

With a conventional gas furnace, warm moist air continuously exits the house through the chimney. This draws cold and dry replacement air into the house through cracks in walls and around windows and doors. This uncontrolled ventilation dehumidifies your home in winter, but consumes heating energy.

Reducing or eliminating this chimney ventilation can save energy but may also increase humidity levels and change the way that air leaks into and out of your home. Homes usually become slightly more positively pressurized.

The increase in humidity and change in air leakage patterns may cause increased condensation/icing: on interior surfaces of well-sealed windows, and anywhere warm moist air leaks out of the home such as electrical outlets, between the panes of poorly sealed windows, on door seals, in door lock mechanisms and around chimney and plumbing stacks. A very small percentage of homeowners have reported experiencing some of these issues.

There is not one solution that works in every home and for every issue. Here are some of the measures that individually or in combination can minimize or eliminate the effects of reduced chimney ventilation:

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- seasonal window insulator kits (clear heat shrink poly over inside windows and frames)
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Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect May 1, 2014

3

Carbon monoxide safety

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The building code now requires permanently mounted carbon monoxide detectors in all new homes with fuel burning appliances or attached garages.

For further details, contact us for a copy of our brochure on "Carbon monoxide safety — Because your family comes first!"

What is the payback?

Determining how many years it will take for a new heating system to pay for itself may help you reach a decision.

Determine the potential savings

Subtract the annual cost of the new heating system you are considering from the annual cost of your current heating system (check the charts).

The difference is approximately what you can expect to save each year, at current energy rates.

Determine the costs of the new system

Determine how much it will cost to buy and install the new system, along with any other adjustments required. Get quotations from three reputable contractors.

Factor in the cost of financing, if necessary.

Determine the payback

Divide the estimated cost of switching your system, by the estimated savings.

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Explanation of technical information in the charts

- Typical annual home heating requirement (output) of 60 Gigajoules is based on Manitoba Hydro's system average for natural gas heated homes.
- Water heating usage is based on Manitoba Hydro's average electric and natural gas water heating household of 2.4 people consuming about 140 litres per day that are heated up an average temperature rise of 50 C.
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- The cost of heating with propane includes a propane tank rental or lease charge of $151 per year for a typical 500 US gallon tank. See table below. This charge may not apply to all customers and may vary.
- The cost of space heating with natural gas includes a basic monthly charge of $14 ($168 per year).
- SE (seasonal efficiency) is defined as the total heat output delivered by the furnace during one heating season as a percentage of the total energy input to the system. SE takes into consideration not only normal operating losses but also the fact that most furnaces rarely run long enough to reach their steady-state efficiency temperature, particularly during milder weather at the beginning and end of the heating season.
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  The SCOP of a geothermal system can vary significantly and is highly dependent on the quality of the system design, installation, commissioning and ongoing maintenance practices.
- Note that the natural gas energy price reflected in the charts is a bundled price that includes primary and supplemental gas, and transportation and distribution charges. For reference, one of the major components of the bundled price is the price of Primary Gas, at 0.1382 per cubic metre. Primary Gas currently comprises 53 per cent of the gas supplied (supplemental gas is 47 per cent.)
- Taxes are not included in these calculations and costs.

ENERGY RATES — in effect May 1, 2014

	Commodity charge	Heating value	
Natural gas	$0.2941/cubic metre	35,310	Btu/cubic metre
Electricity	$0.07381/kilowatt-hour	3,413	Btu/kilowatt-hour
Fuel oil	$1.25/litre	36,500	Btu/litre
Propane	$.65/litre	24,200	Btu/litre

Manitoba Hydro POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect August 1, 2014

1

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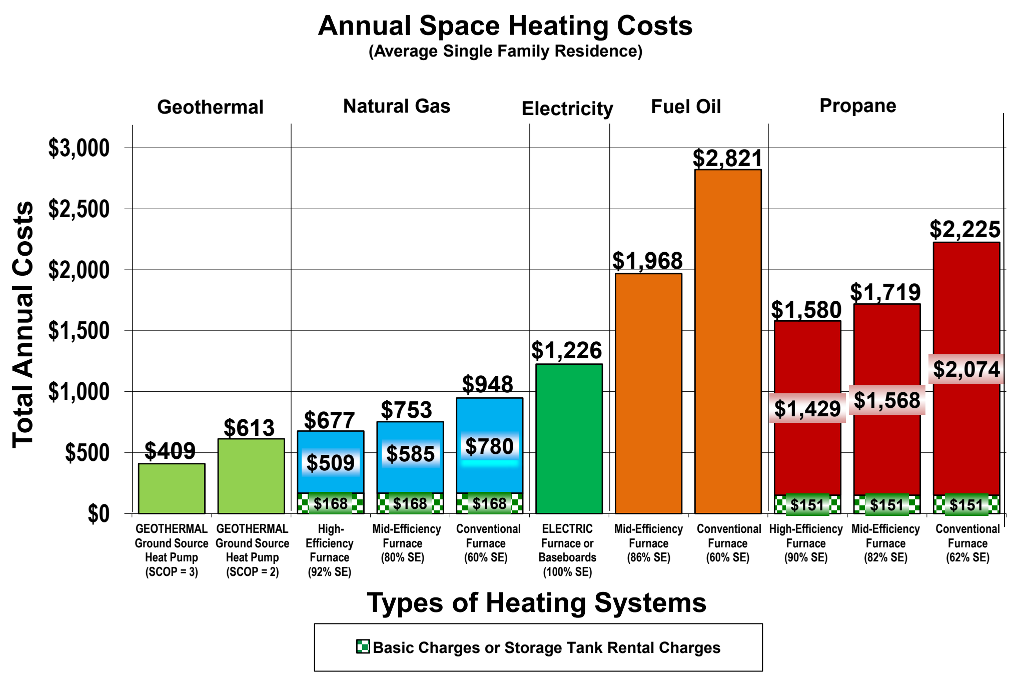

Energy rates

Natural gas:
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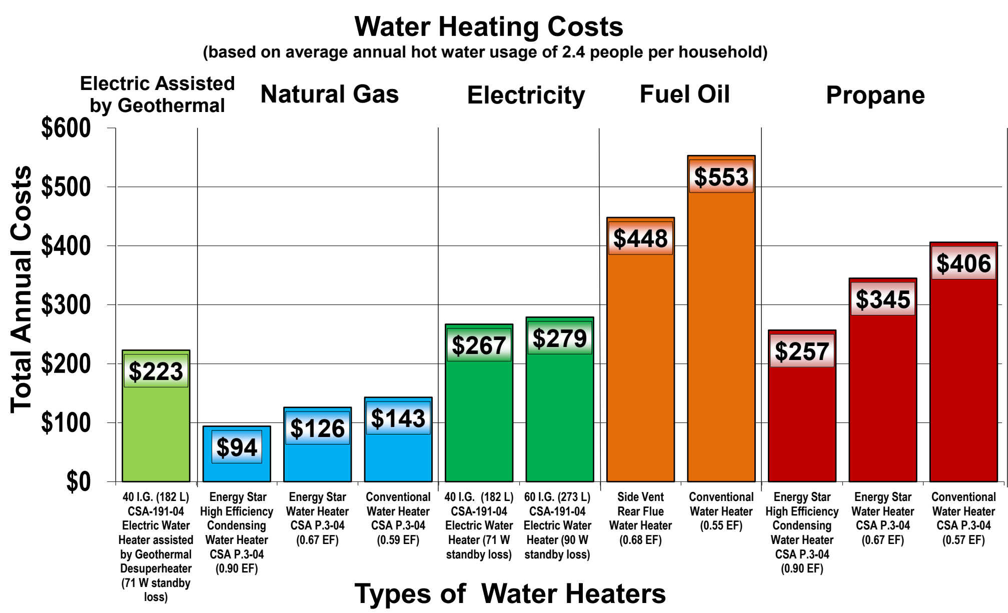

Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect August 1, 2014

2

Weigh your options

The home heating costs shown in the chart are based on the amount of gas used to heat the average natural gas-heated home served by Manitoba Hydro. This average home is about 1,200 square feet and uses a mid-efficiency furnace and conventional gas water heater. Your heating costs may differ due to a variety of factors, such as weather, heating equipment, insulation levels, air tightness and lifestyle. Water heating costs are based on typical usage of the average Manitoba household of 2.4 people.

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Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect August 1, 2014

3

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ENERGY RATES — in effect August 1, 2014

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Manitoba Hydro
POWER SMART*

Typical space & water heating costs

Average single family residence at rates in effect November 1, 2014

1

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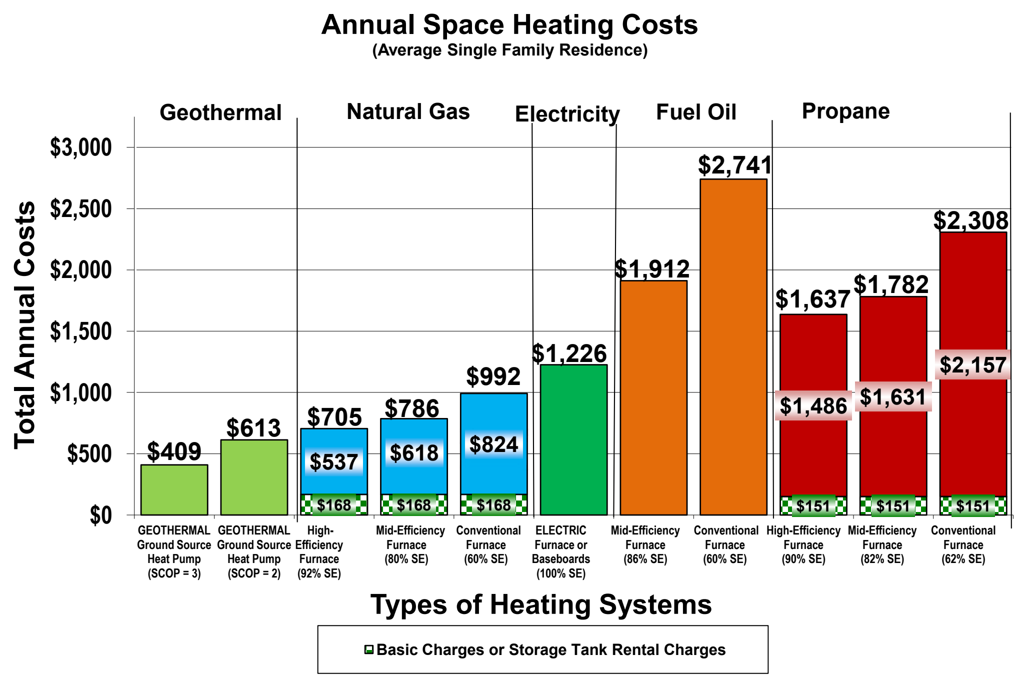

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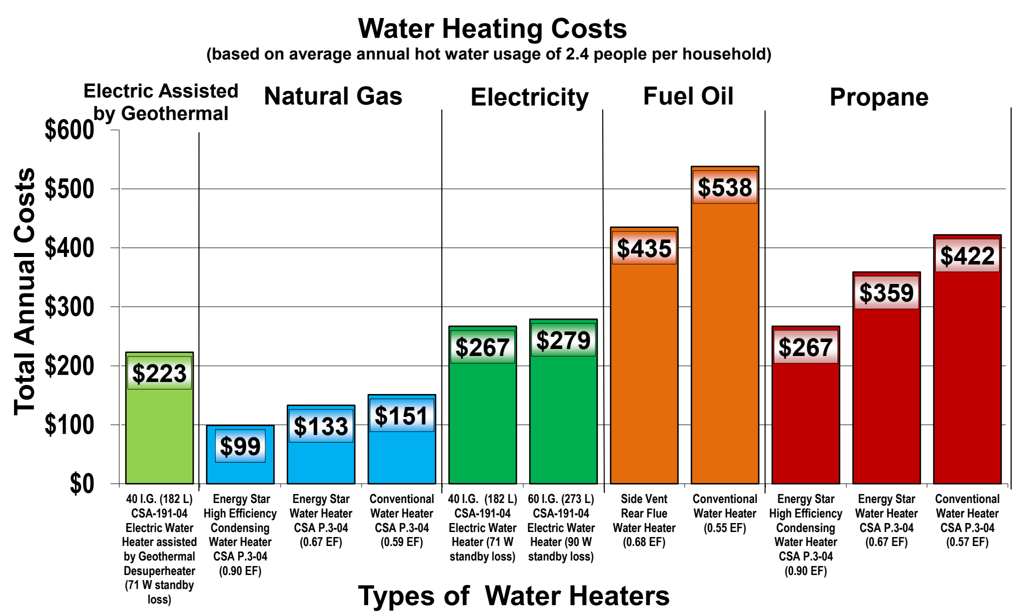

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POWER SMART*

Typical space & water heating costs

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Manitoba Hydro
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3

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  The SCOP of a geothermal heat pump system typically ranges from 2.0 to 3.0. For reference, the SCOP of an electric baseboard heater is 1.0. The SCOP rating accounts for cycling losses, circulating fan and pump energy and auxiliary electric heating loads which are not included in the manufacturer's COP rating of the heat pump "unit". The overall system SCOP will therefore always be significantly lower than the unit COP.

  The SCOP of a geothermal system can vary significantly and is highly dependent on the quality of the system design, installation, commissioning and ongoing maintenance practices.
- Note that the natural gas energy price reflected in the charts is a bundled price that includes primary and supplemental gas, and transportation and distribution charges. For reference, one of the major components of the bundled price is the price of Primary Gas, at $0.1665 per cubic metre. Primary Gas currently comprises 92 per cent of the gas supplied (supplemental gas is 8 per cent.)
- Taxes are not included in these calculations and costs.

ENERGY RATES — in effect November 1, 2014

	Commodity charge	Heating value	
Natural gas	$0.308/cubic metre	35,310	Btu/cubic metre
Electricity	$0.07381/kilowatt-hour	3,413	Btu/kilowatt-hour
Fuel oil	$1.059/litre	36,500	Btu/litre
Propane	$0.571/litre	24,200	Btu/litre

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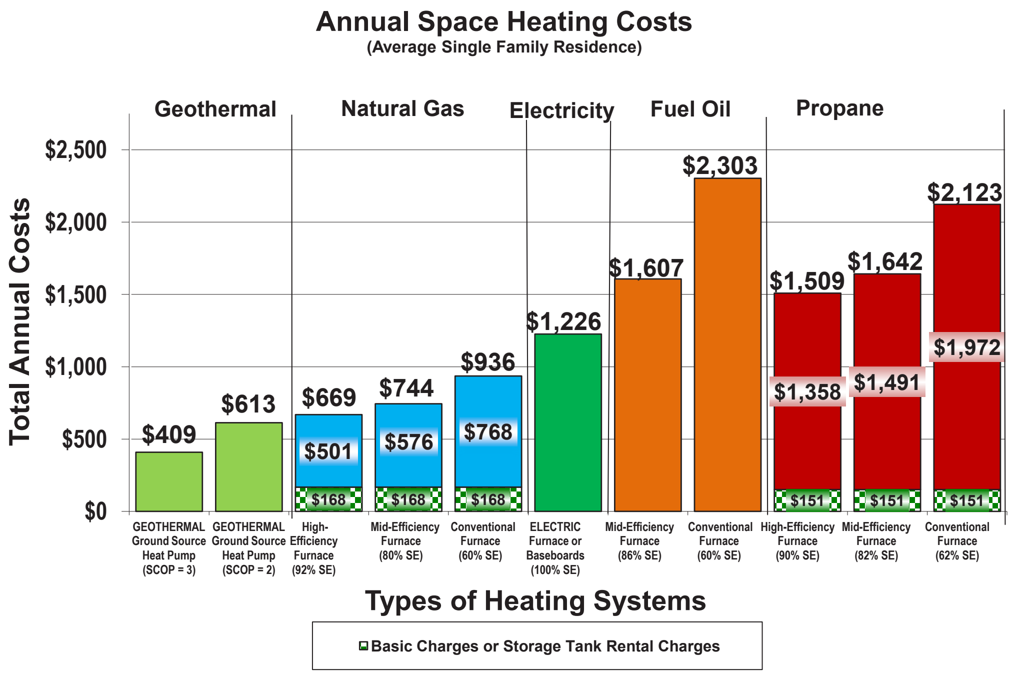
Typical space & water heating costs

Average single family residence at rates in effect February 1, 2015

1

Wondering about your energy options for heating?

1. Consult the charts to identify the costs of your current home heating and water heating systems.
2. Review the costs of other systems to see how your costs compare.
3. Consult the accompanying notes for guidance if you are thinking of switching systems or building a new home.



Energy rates

Natural gas:
$0.2871/cubic metre

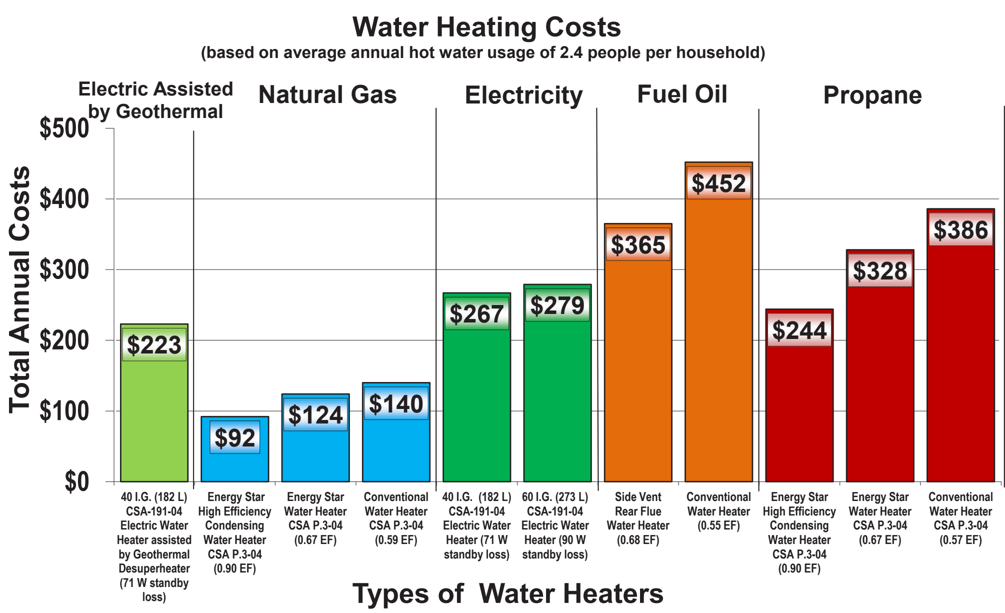
Electricity:
$0.07381/kilowatt-hour

Fuel oil:
$**0.89**/litre

Propane:
$0.522/litre

Basic monthly charge for natural gas is **$14** (**$168** per year)

Annual propane tank rental: **$151**



Manitoba Hydro
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Typical space & water heating costs

Average single family residence at rates in effect February 1, 2015

2

Weigh your options

The home heating costs shown in the chart are based on the amount of gas used to heat the average natural gas-heated home served by Manitoba Hydro. This average home is about 1,200 square feet and uses a mid-efficiency furnace and conventional gas water heater. Your heating costs may differ due to a variety of factors, such as weather, heating equipment, insulation levels, air tightness and lifestyle. Water heating costs are based on typical usage of the average Manitoba household of 2.4 people.

Annual cost estimates

The charts present annual costs as if all energy rates remained fixed for the coming year at rates in effect on February 1, 2015.

Your actual annual costs will vary, since natural gas rates change four times a year, while propane and oil rates can change weekly. Note that Primary Gas represents the bulk of the gas used. With Manitoba Hydro's Quarterly Rate Service, the price you pay for Primary Gas is the same price we pay for the gas in the marketplace. This rate changes every 3 months and is currently $0.1252 per cubic metre. If you buy Primary Gas on a Fixed Rate Service contract from Manitoba Hydro or a Gas Broker, you will continue to pay Manitoba Hydro for Supplemental Gas as well as transportation and distribution charges. The figure of $0.2871 per cubic metre of natural gas that we've used in the charts is known as a "re-bundled" effective rate. It includes charges for Primary and Supplemental gas, as well as for transportation and distribution of the gas on Manitoba Hydro's Quarterly Rate Service.

Key points if you are thinking of converting

Is it economically feasible?

Note that the costs of switching to another system to heat your home and hot water may be economically feasible only if your current system is at or near the end of its useful life, or if you are building a new home. Be sure to obtain quotations from at least three reputable heating contractors before you make your decision.

Conventional furnaces no longer manufactured

The space heating chart includes conventional natural gas, fuel oil, and propane furnaces. These conventional furnaces have not been manufactured since 1992, but many are still in operation.

High efficiency furnaces are now required by law

Effective December 30, 2009 the Province of Manitoba enacted legislation controlling the sale and lease of gas and propane heating equipment. Visit www.greenmanitoba.ca (click on the energy tab) for more information on this regulation.

Size of existing electrical service

Your electrical system may need to be upgraded if you want it to carry a heating load.

Depending on the capacity of the electrical appliances and equipment currently installed, and the size of your home, the Manitoba Electrical Code will allow a maximum of 8 to 10 kilowatts of electric heating on a standard 100-amp service. Most homes will need more than this.

Increasing the size of an electrical service usually involves changing your electrical panel or installing an additional one. An electrician should perform an electrical code load calculation to advise whether your existing service is adequate to serve the heating equipment required to heat your home.

Other gas appliances

If you have other appliances in your home like a range, clothes dryer, fireplace, or swimming pool heater, switching to an all-electric system may be quite costly.

Flue Gas Venting

When natural gas is burned, flue gases are produced which primarily contain carbon dioxide and water vapour which are not harmful to people. However, flue gases can also contain trace amounts of carbon monoxide and other gases that can present a health hazard. High-efficiency natural gas furnaces will not use the existing chimney to vent (remove) flue gases from the home. Instead they will be vented via approved plastic piping through the home's side wall or roof.

If you have a standard natural gas water heater, the Manitoba Gas Notices allow it to continue to use the existing chimney if it is in good condition and meets the requirements of the Code Authority Having Jurisdiction (Manitoba Dept. of Labour). Your heating contractor should inform you if the chimney has corroded or does not meet the code requirements. Generally, installing a new approved smaller diameter chimney liner may meet the requirements.

Issues that can arise once the natural gas water heater vents alone on the old chimney include: flue gases condensing in the chimney, or flue gas spillage into the home. If these venting problems occur, you may need to upgrade your venting system or have other work performed to rectify them. If the upgrades are costly, other options to consider are replacing the conventional heater with a side-wall vented gas water heater or an electric water heater.

Reduced chimney ventilation

Converting to electric heat or to a high-efficiency gas furnace will reduce the uncontrolled ventilation provided by the chimney. The uncontrolled chimney ventilation will be completely eliminated if you also replace your conventional gas water heater and either remove or cap off the chimney.

With a conventional gas furnace, warm moist air continuously exits the house through the chimney. This draws cold and dry replacement air into the house through cracks in walls and around windows and doors. This uncontrolled ventilation dehumidifies your home in winter, but consumes heating energy.

Reducing or eliminating this chimney ventilation can save energy but may also increase humidity levels and change the way that air leaks into and out of your home. Homes usually become slightly more positively pressurized.

The increase in humidity and change in air leakage patterns may cause increased condensation/icing: on interior surfaces of well-sealed windows, and anywhere warm moist air leaks out of the home such as electrical outlets, between the panes of poorly sealed windows, on door seals, in door lock mechanisms and around chimney and plumbing stacks. A very small percentage of homeowners have reported experiencing some of these issues.

There is not one solution that works in every home and for every issue. Here are some of the measures that individually or in combination can minimize or eliminate the effects of reduced chimney ventilation:

- improved weatherstripping and caulking on doors and windows and other areas of air leakage (but not on storm doors)
- seasonal window insulator kits (clear heat shrink poly over inside windows and frames)
- improved windows (preferably triple pane)
- a ventilation system which may consist of:
  - exhaust fan(s)
  - exhaust fan(s) combined with a fresh air intake
  - heat recovery ventilator (HRV)

Manitoba Hydro
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Typical space & water heating costs

Average single family residence at rates in effect February 1, 2015

3

Carbon monoxide safety

If you are burning heating oil, diesel, propane, kerosene, natural gas, wood, or coal in your home, or if you have an attached garage, we recommend that you install at least one carbon monoxide detector in your home.

The building code now requires permanently mounted carbon monoxide detectors in all new homes with fuel burning appliances or attached garages.

For further details, contact us for a copy of our brochure on "Carbon monoxide safety — Because your family comes first!"

What is the payback?

Determining how many years it will take for a new heating system to pay for itself may help you reach a decision.

Determine the potential savings

Subtract the annual cost of the new heating system you are considering from the annual cost of your current heating system (check the charts).

The difference is approximately what you can expect to save each year, at current energy rates.

Determine the costs of the new system

Determine how much it will cost to buy and install the new system, along with any other adjustments required. Get quotations from three reputable contractors.

Factor in the cost of financing, if necessary.

Determine the payback

Divide the estimated cost of switching your system, by the estimated savings.

The result is the number of years it will take for the new system to pay for itself.

Explanation of technical information in the charts

- Typical annual home heating requirement (output) of 60 Gigajoules is based on Manitoba Hydro's system average for natural gas heated homes.
- Water heating usage is based on Manitoba Hydro's average electric and natural gas water heating household of 2.4 people consuming about 140 litres per day that are heated up an average temperature rise of 50 C.
- The Electric water heating assisted by geothermal desuperheater option is based on Manitoba Hydro's field monitoring of nine homes with geothermal heating and desuperheaters where 80 per cent of the average water heating load was provided by the electric heating elements of the water tank and 20 per cent by the desuperheater.
- The cost of heating with propane includes a propane tank rental or lease charge of $151 per year for a typical 500 US gallon tank. See table below. This charge may not apply to all customers and may vary.
- The cost of space heating with natural gas includes a basic monthly charge of $14 ($168 per year).
- SE (seasonal efficiency) is defined as the total heat output delivered by the furnace during one heating season as a percentage of the total energy input to the system. SE takes into consideration not only normal operating losses but also the fact that most furnaces rarely run long enough to reach their steady-state efficiency temperature, particularly during milder weather at the beginning and end of the heating season.
- Energy Factor (EF) is an overall efficiency rating of the water heater. The higher the EF, the more efficient the model. Electric water heaters are required to have maximum standby losses of 71 watts for a 40 gallon and 90 Watts for a 60 gallon.
- SCOP (Seasonal Coefficient of Performance) = 2 and = 3 appears in the home heating chart under geothermal closed loop heat pump. It refers to the Seasonal Coefficient of Performance of the heat pump over an entire heating season.

  SCOP is defined as the total heat output of the system during the heating season, divided by the total energy input to the system.

  The SCOP of a geothermal heat pump system typically ranges from 2.0 to 3.0. For reference, the SCOP of an electric baseboard heater is 1.0. The SCOP rating accounts for cycling losses, circulating fan and pump energy and auxiliary electric heating loads which are not included in the manufacturer's COP rating of the heat pump "unit". The overall system SCOP will therefore always be significantly lower than the unit COP.

  The SCOP of a geothermal system can vary significantly and is highly dependent on the quality of the system design, installation, commissioning and ongoing maintenance practices.
- Note that the natural gas energy price reflected in the charts is a bundled price that includes primary and supplemental gas, and transportation and distribution charges. For reference, one of the major components of the bundled price is the price of Primary Gas, at $0.1252 per cubic metre. Primary Gas currently comprises 89 per cent of the gas supplied (supplemental gas is 11 per cent.)
- Taxes are not included in these calculations and costs.

ENERGY RATES — in effect February 1, 2015

	Commodity charge	Heating value	
Natural gas	$0.2871/cubic metre	35,310	Btu/cubic metre
Electricity	$0.07381/kilowatt-hour	3,413	Btu/kilowatt-hour
Fuel oil	$0.89/litre	36,500	Btu/litre
Propane	$0.522/litre	24,200	Btu/litre

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Section:	11	**Page No.:**	Appendix 11.49
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation Expense		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a breakdown of costs incurred by MH related to conversion to ELG. This should include internal costs and external costs broken down by consultant, which costs should be further broken down discretely by conversion effort and specific depreciation study.

b) On the same basis as (a), provide an estimate as to the costs that would be incurred related to the preparation of an IFRS-compliant ASL-based methodology.

RATIONALE FOR QUESTION:

To understand the costs related to conversion to ELG compared to continuing to use ASL.

RESPONSE:

a) The process to prepare for the April 1, 2015 conversion to the ELG method involved the selection of additional asset components in combination with the 2010 Depreciation Study, as well as efforts to re-allocate costs from existing asset components to the new component groups (asset conversion). Please note that, for efficiency purposes, the work associated with identifying additional asset components was blended with the work required for completing the 2010 Depreciation Study. For example, interviews and site tours conducted by Gannett Fleming with accounting and operations staff involved both an assessment of potential new components (for conversion to IFRS) and an assessment of the service lives of assets in existing and new component groups (for the 2010 Depreciation Study). Time was not tracked separately between activities pertaining to the identification of additional components and activities pertaining to the depreciation study and as such, it is not possible to segregate many of the costs between the two activities. The breakdown of the costs incurred to date is as follows:

2010 Depreciation Study / Identification of New Asset Components Under IFRS:

Work Performed By	Activities	Cost ($ millions)
Manitoba Hydro staff (Corporate Controller staff, engineers, and management)	- Interview operations staff - Identify additional asset components - Validate new components with engineers, depreciation consultant - Implement IT, SAP related changes - Prepare / review historical accounting records - Provide staff with awareness and understanding of new components - Prepare GRA material, respond to IR's	$0.9
Gannett Fleming	- Engagement to assist with IFRS related issues and complete the 2010 Depreciation Study as follows: ▪ Develop new asset components that comply with IFRS ▪ Develop historic cost and accumulated depreciation for existing and new asset components ▪ Develop depreciation rates for new and existing asset components ▪ Develop additional depreciation scenarios for ASL and ELG procedures with and without net salvage ▪ Provide support for year-end audit questions from Ernst & young	$0.2
Gannett Fleming (Regulatory Support)	- Regulatory support for Manitoba Hydro's 2012/13 and 2013/14 GRA ▪ Assist with the preparation of responses to IR's and undertakings ▪ Participate as a witness	$.05
Total costs		**$1.15**

Please note that the cost of $1.15 million do not include the cost of the 2014 Depreciation Study, or the costs associated with the response to PUB directives 8 & 9 in Order 43/13.

Asset Conversion Costs - New Components:

Asset conversion costs were incurred by Manitoba Hydro staff primarily in the Corporate Controller Division with the assistance of operations staff. These efforts have been ongoing following Manitoba Hydro's completion of the 2010 Depreciation Study in 2012 and, given the high volume of transactional data to analyze, will not be completed until 2015. The overall goal of the conversion effort is to balance efficiency and accuracy in reviewing historical accounting records so as to re-allocate costs between existing and new asset components. For many of the new asset components, historical costs are not readily available as the cost information was not recognized in accordance with the new component such that estimates of the costs have to be made based on recent information and information collected from operations staff. The costs incurred for asset conversion are as follows:

Work Performed By	Activities	Cost ($ millions)
Manitoba Hydro staff (Corporate Controller staff, engineers, and management)	- Review historical accounting / cost records to assess opening costs for each asset component group - Confirm asset costs with engineering staff – develop estimates where necessary - Re-allocate costs between existing and new component groups - Re-allocate costs between components for ongoing projects - Provide staff with awareness and understanding of new components	$1.7
Total		**$1.7**

b) An estimate as to the costs that would be incurred for the preparation of an IFRS-compliant ASL-based methodology would include both a depreciation study and asset conversion. An estimate of these costs is as follows:

Depreciation Study/Identification of Additional Asset Components:

Work Performed By	Activities	Cost ($ millions)
Manitoba Hydro staff (Corporate Controller staff, engineers, and management)	- Interview operations staff - Identify additional asset components - Validate new components with engineers, depreciation consultant - Implement IT, SAP related changes - Prepare / review historical accounting records - Provide staff with awareness and understanding of new components - Prepare GRA material, respond to IR's	$0.7
Gannett Fleming*	- Engagement to assist with IFRS compliant ASL method as follows: ▪ Develop new asset components that comply with IFRS ▪ Develop historic cost and accumulated depreciation for existing and new asset components ▪ Develop depreciation rates for new and existing asset components ▪ Develop additional depreciation scenarios ▪ Provide support for year-end audit questions from Ernst & young	$0.2
Gannett Fleming* (Regulatory Support)	- Regulatory support for future Manitoba Hydro GRA ▪ Assist with the preparation of responses to IR's and undertakings ▪ Participate as a witness	$.05
Total costs		**$.95**

*These estimates not confirmed with Gannett Fleming

Estimated Asset Conversion Costs (IFRS compliant ASL method):

Work Performed By	Activities	Cost ($ millions)
Manitoba Hydro staff (Corporate Controller staff, engineers)	- Review historical accounting / cost records to assess opening costs for each asset component group - Confirm asset costs with engineering staff – develop estimates where necessary - Re-allocate costs between existing and new component groups - Re-allocate costs between components for ongoing projects - Provide staff with awareness and understanding of new components	$1.5
Total costs		**$1.5**

Section:		Page No.:	
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation		
Issue:	Treatment of Gains and Losses on Asset Retirement		

PREAMBLE TO IR (IF ANY):

MH has stated that:

> *"Currently under CGAAP, Manitoba Hydro follows a common industry practice for regulated utilities whereby asset retirement gains and losses are recorded in the accumulated depreciation account for the retired asset's respective component group. Such gains and losses are then factored into future depreciation rate changes for the component group and are recognized in net income over time, as part of future years' depreciation expense."*

QUESTION:

a) Please indicate whether the existing regulatory practice could continue for rate setting and financial reporting purposes. Discuss the implications related to Financial Reporting.

b) Please file Manitoba Hydro's external auditor's opinion/report(s) related to the continuation of the current accounting practice.

RATIONALE FOR QUESTION:

To understand the implications of retaining an existing accounting practice.

RESPONSE:

a) The existing regulatory practice whereby asset retirement gains and losses are recorded in the accumulated depreciation account for the retired asset's respective component group and then factored into future depreciation rate changes for the group may be continued for rate setting purposes if ordered by the PUB, but cannot be continued for financial reporting purposes under IFRS. IFRS specifically requires gains and losses on the retirement of an asset to be recognized in net income immediately. As per IFRS standard IAS 16, Property, plant and Equipment:

68 *The gain or loss arising from the derecognition of an item of property, plant and equipment shall be included in profit or loss when the item is derecognized*

If the PUB directed the continuation of the current CGAAP practice of recording asset retirement gains and losses in the accumulated depreciation account for rate-setting purposes upon the adoption of IFRS, Manitoba Hydro would be required to establish a regulatory deferral account for financial reporting to capture the difference in the accounting for gains and losses between the rate-setting and the financial reporting purposes. This accounting treatment would be necessary for compliance with the requirements of IFRS standard *IFRS 14 – Regulatory Deferral Accounts*.

In addition, as further outlined in the response to PUB/MH-II-21c, if the recognition of asset retirement gains and losses is different for rate-setting purposes from the method used for financial reporting, Manitoba Hydro will be required to incur the additional administrative costs of having to maintain two separate set of asset sub-ledgers to capture the thousands of transactions that occur for PP&E assets over the course of a year. Notably, Manitoba Hydro expects asset retirement gains and losses to be lower when using the ELG method under IFRS.

b) Manitoba Hydro has not engaged its auditor Ernst & Young to provide an opinion/report(s) related to the continuation of the current accounting practice of recording asset retirement gains and losses in accumulated depreciation and as such, a report does not exist.

Section:	5	Page No.:	Appendix 11.49 MH Exhibit #57 2012 GRA
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation Expense		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

Gannett Fleming states in its Depreciation Analysis that:

> *"Gannett Fleming does not view that the current level of Manitoba Hydro asset componentization is sufficient if using the ASL method for financial statements prepared under IFRS. In the experience of Gannett Fleming, electric generation utilities across Canada that use the ASL procedure have a significantly increased level of componentization for financial reporting purposes. Gannett Fleming views that Manitoba Hydro's current level of depreciable components would need to be broken down into additional components based on asset dollar value, differing service lives and differing forces of retirement in order for Manitoba Hydro to continue using the ASL procedure in the development of depreciation rates under the IFRS."*

QUESTION:

a) Please have Gannett Fleming provide an update to MH Exhibit #57 from the 2012 GRA.

b) Please indicate whether any of the account groupings have changed from what was presented.

c) If available, please provide a copy of the detailed account listings for BC Hydro, Newfoundland and Labrador Hydro and SaskPower.

d) Please indicate whether the account grouping of the listed utilities are IFRS compliant.

RATIONALE FOR QUESTION:

To understand the practices with respect to ELG and ASL in other jurisdictions.

RESPONSE:

a) Please see the response to MIPUG-MH-I-16(a) for an update to MH Exhibit #57 from the 2012 GRA.

b) Two new peer group depreciation studies (2014 study for AltaLink and the 2013 study for Ontario Power Generation) were filed as compared to the peer group studies filed in Manitoba Hydro's 2012/13 GRA. No depreciation study for Ontario Power Generation was filed in the previous GRA so there is no information to compare to. The 2014 AltaLink depreciation study information is updated from the 2010 study information filed in the 2012/13 GRA, but includes the same accounts.

c) Please see the response to MIPUG-MH-I-16(a) for copies of the detailed account listings for BC Hydro, Newfoundland and Labrador Hydro and SaskPower.

d) Manitoba Hydro and Gannett Fleming are not in a position to know whether or not the account listings for BC Hydro, Newfoundland and Labrador Hydro and SaskPower are IFRS compliant. SaskPower is currently reporting under IFRS and thus, one could assume their process for determining depreciation is IFRS compliant.

Section:	Tab 7, App. 7.1	**Page No.:**	Table 14, p.18
Topic:	Electric Load Forecast		
Subtopic:	Domestic Load Forecasts Residential Sales Forecasts		
Issue:	Electric Heating		

PREAMBLE TO IR (IF ANY):

MH's Residential Sales forecasts suggest an ongoing shift to electric heat and water heating. This ignores the increasing spread between electric and natural gas supply costs.

QUESTION:

a) Provide a typical residential total energy bill comparison for all-electric vs. natural gas heating customers in Winnipeg for the next ten years.

b) Provide a typical residential total energy bill for an electric heat customer in Thompson for the next ten years.

c) Provide a typical residential total energy bill for an electric heat customer in a rural northern Manitoba home for the next ten years.

d) For each of (a) through (c), define what constitutes a 'typical' residential home in each of the categories.

RATIONALE FOR QUESTION:

To understand the magnitude of future electric heating energy bills.

RESPONSE:

For parts a) to c), please see Manitoba Hydro's response to PUB/MH-II-58b.

For part d), please see Manitoba Hydro's response to PUB/MH-II-58a.

Section:	Tab 9, App. 9.1	Page No.:	pp. 4 to 6
Topic:	Energy Supply		
Subtopic:	Export Sales		
Issue:	NEB-MISO Sales- Timing/ Make-up of MISO sales		

PREAMBLE TO IR (IF ANY):

MH's MISO sales in 2014/15 as reported to the NEB break down as follows:

	Firm Contracts (GWh)	Non-firm 5x16 (GWh)	Non-firm 2x16 (GWh)	Non-firm 7x8 (GWh)	Total MISO Sales (GWh)
Apr	280③	350①	60	0	690
May	280③	350①	144	0	774
Jun	400③	230①	270	251	1151②
Jul	460③	170①	270	366	1266②
Aug	460③	170①	270	394	1294②
Sep	300③	330①	270	58	958
Oct	180	160	0	0	340
Nov	160	390	0	0	550
Dec (forecast)	170	150④	0	0	270
Jan (forecast)	170	150④	0	0	270
Feb (forecast)	150	150④	0	0	250
Mar (forecast)	170	150④	0	0	270

① MH apparently achieved 100% of 5x16 US tie-line capacity.

② MH apparently achieved 90% of the 7x24 US-Intertie line capacity.

③ Includes Diversity Sales with zero capacity revenue

④ May include bilateral opportunity sales

QUESTION:

Confirm or revise the breakdown of MISO energy sales in the above table.

RATIONALE FOR QUESTION:

To assess the types of sales Manitoba Hydro can achieve in MISO.

RESPONSE:

Manitoba Hydro cannot confirm the information in the table provided. Information provided to the NEB as required by its export permits is not sales data, rather it is energy that is sourced in Canada for physical export to the US using the appropriate NEB permit. US sales are routinely greater than delivery as sales can be sourced from energy purchased in the US. As these sales are not sourced in Canada, they are not reported to the NEB as exports from Canada.

In addition the question assumes that all sales are MISO sales. This is incorrect in that MISO sales are only a portion of MH's total US sales. Lastly the question assumes that Diversity Sales were reported to the NEB as Interruptible Sales. Rather Diversity Sales are reported to the NEB under the NEB Diversity Agreement firm export permits.

Below is the revised breakdown of the US energy sales based on the NEB breakdown provided in Tab 9, App. 9.1.

The data provided in the table below is based on actual deliveries for 2014/15.

	Firm Contracts GWh	Non Firm 5 x 16 GWh	Non Firm 2 x 16 GWh	Non Firm 7 x 8 GWh
April	264	182	132	112
May	273	159	146	195
June	406	238	187	320
July	460	232	201	373
August	451	206	239	398
September	383	181	141	253
October	182	30	43	87
November	160	126	111	150
December	184	106	114	103
January	176	118	102	73
February	160	49	27	15
March	176	168	119	142

Section:	5	Page No.:	Appendix 11.49
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation Expense		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a breakdown of costs incurred by MH related to conversion to ELG, including internal costs and external costs broken down by consultant including costs broken down discretely by conversion efforts, and specific depreciation study.

b) Please provide a similar breakdown in to (a) related to an IFRS compliant ASL based methodology.

RATIONALE FOR QUESTION:

To understand the costs related to conversion to ELG.

RESPONSE:

Please see the responses to PUB/MH-II-59a and PUB/MH-II-59b, which provides a breakdown of costs incurred by Manitoba Hydro for the conversion to ELG and an estimate as to the costs that would be incurred for the preparation of an IFRS compliant ASL based methodology.

Section:	Tab 3	Page No.:	
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	MISO Export Contracts		
Issue:	Market Prices for Firm Contract Sales		

PREAMBLE TO IR (IF ANY):

In Appendix 11.20, MH's tabulation of monthly NEB transactions includes a Permit No. 379 Firm Summer Sale commencing in June of 2013 and carrying into 2014. This sale previously was reported as Interruptible.

QUESTION:

a) Where in Manitoba Hydro's list of contractual counterparties is this party disclosed?
b) What are the MW capacity and GWh energy involved?
c) Confirm that the sale attracts MISO market average energy prices with no explicit capacity revenue.
d) Explain the rationale for a contract that earns market price revenues.

RATIONALE FOR QUESTION:

To explore Manitoba Hydro's export revenue projections.

RESPONSE:

a) Permit 379 is in relation to the WPS 108 MW Surplus Energy Sale.

b) The WPS 108 MW Surplus Energy Sale is an energy sale only with an export volume up to 946 GWh annually.

c) Energy prices associated with specific contracts are considered to be confidential and as such, the information requested cannot be disclosed.

d) This energy sale requires WPS to hold firm MISO transmission to Wisconsin which increases Manitoba Hydro firm US market access. As indicated in c), the energy price associated with this contract is considered confidential and cannot be disclosed.

Section:	Appendices 11.20/11.21/11.22	Page No.:	
Topic:	Minimum Filing Requirements		
Subtopic:	Opportunity Sales		
Issue:	Winter Imports		

PREAMBLE TO IR (IF ANY):

MH's supply-demand tables suggest that the winter 2013/14 Domestic Load Peak Demand of 4713 MW (gross) could have been met by hydraulic generation resources. In PUB/MH I-82(a), MH indicates that that was not possible and capacity imports were required in a high flow year.

QUESTION:

a) Explain why Manitoba Hydro imports power during the winter months, when Manitoba Hydro's hydraulic capacity is sufficient to meet Manitoba's domestic load requirements.

b) To the extent that imports were required as a result of Manitoba Hydro having to meet export commitments during the relevant timeframe, please quantify these commitments and the resulting capacity shortage.

RATIONALE FOR QUESTION:

To assess the impact of exports on Manitoba Hydro's ability to meet domestic demand from domestic sources.

RESPONSE:

a) In order to serve its load, Manitoba Hydro needs both sufficient capacity and sufficient energy supplies. As indicated in the question, to meet peak demands it appears that Manitoba Hydro has sufficient hydraulic capacity to do so. However, from an energy perspective there may be insufficient hydraulic energy flowing in Manitoba rivers in the winter to meet the Manitoba energy requirement.

As a result, additional non-hydraulic energy supplies must be used. This energy can be sourced from wind generation in Manitoba, market purchases or thermal generation. Under the wind Power Purchase Agreements, Manitoba Hydro must buy any wind energy generated in the province so this energy supply is used first to augment the hydraulic energy supply. To the extent additional energy is required, generally it can be sourced from the MISO off peak market at least cost. So if additional energy is needed, off peaks imports are scheduled. Once that supply is maxed out, energy is next purchased in the on peak hours but only to the extent that it costs less than Manitoba Hydro's incremental cost of thermal generation at Brandon and Selkirk.

In the winter, hydraulic energy is limited due to ice restrictions in the outlet channels from Lake Winnipeg. These ice restrictions can limit the outflow on the Nelson River by up to 50% from what is possible in the open water season. To minimize the shortfall in the Nelson River hydraulic energy supply in the winter, Manitoba Hydro generally operates Lake Winnipeg to the maximum possible discharge from December through March.

b) Manitoba Hydro's export commitments do not result in a capacity shortage. Despite the record cold conditions in Manitoba during the winter of 2013/14, Manitoba Hydro was still exporting during all but a few on-peak hours. During the December 2013 through February 2014 period, on-peak net metered interchange was into Manitoba (i.e. in the import direction) for approximately 1% of the hours. The quantity of on-peak power that flowed into Manitoba was also comparatively very little, and totaled only 0.2% of the net metered export quantity for this period.

Section:	Appendix 11.15 MFR 9 Appendix 11.37 MFR 4	Page No.:	2014 Annual Report, pp.106&107
Topic:	Minimum Filing Requirements		
Subtopic:	Internally Generated Funds		
Issue:	Surplus to Sustaining Capital spending		

PREAMBLE TO IR (IF ANY):

Since 2007/08 MH has counted increasingly on domestic revenue to fund sustaining capital spending:

	Cash Flow from Operations ($M) [1]*	Net Export Revenues ($M) [2]**	Domestic Revenue Component ($M) [3= 1-2]	Sustaining Capital Spending ($M) [4]*	Export Revenue Contributions ($M) [5=4-3]
2007/08	599	367	232	357	125
2008/09	653	324	329	349	20
2009/10	528	202	324	405	81
2010/11	550	172	388	443	55
2011/12	518	98	420	465	45
2012/13	554	102	442	433	(9)
2013/14	661	127	534	470	(64)
2014/15	558	155	407	571	164
2015/16	587	181	406	577	171
2016/17	571	147	324	610	286
2017/18	598	243	355	547	192
2018/19	482	160	222	547	215
2019/20	441	195	246	548	302
2020/21	469	259	210	573	363
2021/22	522	553	(31)	555	586
2022/23	613	570	43	563	520
2023/24	699	588	111	571	460

Sources:

* Cash Flow from Operations and Sustaining Capital Spending from Appendix 11.37

** Net Export Revenue historical information from 2014 Annual Report pp.106&107, forecast information based on Appendix 11.15

QUESTION:

a) Confirm that MH's sustaining capital has been increasingly funded from domestic revenue.

b) Confirm that after 2012/13 and 2013/14, the export revenue contribution to Sustaining Capital has become negative.

c) Confirm that after 2014, MH anticipates funding Sustaining Capial increasingly from export revenues.

RATIONALE FOR QUESTION:

To explore Manitoba Hydro's ability to sustaining capital expenditures from internally generated funds.

RESPONSE:

Manitoba Hydro does not accept the calculated source of sustaining capital expenditure funding provided in the table above. Column 5 is incorrect as the calculated export revenue contribution in 2015, 2017 and 2019 to 2022 exceeds the net export revenues in those years and fails to recognize that sustaining capital expenditures are increasingly funded by debt due to a shortfall in internally generated funds.

Please see the response to PUB/MH-II-30 for a notional proportionate allocation of cash flow from operations, based on a breakdown of cash flow from customers (including domestic and export), to Manitoba Hydro's electric operations sustaining capital expenditures.

Section:	Appendix 11.19 MFR 1	**Page No.:**	
Topic:	Minimum Filing Requirements		
Subtopic:	Total Income		
Issue:	IFF11-2 vs. IFF14		

PREAMBLE TO IR (IF ANY):

The 2014/15 interim rate increase of 2.75% was reflective of IFF11-2 financial circumstances. These have changed in IFF12, IIF13 and IIF14. Actual net revenues for 2013/14 were significantly higher than forecast in IFF11-2 and for 2014/15 will also be higher.

QUESTION:

Confirm or amend the Net Revenue table for 2013/14 and 2014/15:

		IFF11-2	IFF12	IFF13	IFF14	Actual
Domestic Sales:	- in 2014/15	1462	1478	1463	1432	n/a
	- in 2013/14	1400	1409	1396	N/A	1424
Export Sales:	- in 2014/15	394	296	383	434	n/a
	- in 2013/14	363	296	408	N/A	439
Total Revenue:	- in 2014/15	1873	1774	1846	1864	n/a
	- in 2013/14	1778	1105	1804	N/A	1867
Water Rentals	- in 2014/15	113	103	123	123	n/a
	- in 2013/14	112	108	125	N/A	126
F&PP:	- in 2014/15	187	133	142	130	n/a
	- in 2013/14	158	117	144	N/A	177
Net Revenue:	- in 2014/15	1573	1538	1581	1611	n/a
	- in 2013/14	1508	1478	1535	N/A	1564

RATIONALE FOR QUESTION:

To explore changes to Manitoba Hydro's financial position.

RESPONSE:

The 2014/15 interim rate application was based upon the financial outlook in IFF13, and not IFF11-2 as indicated in the preamble to the question.

Please see the following table with the amended values (in blue font).

		MH11-2	MH12	MH13	MH14	Actual
Domestic Sales:	- in 2014/15	1 463	1 478	1 442	1 407	n/a
	- in 2013/14	1 399	1 409	1 378	N/A	1 405
Export Sales:	- in 2014/15	394	343	383	409	n/a
	- in 2013/14	363	344	408	N/A	439
Other Revenue:	- in 2014/15	16	15	13	15	n/a
	- in 2013/14	16	15	13	N/A	22
Total Revenue:	- in 2014/15	1 873	1 836	1 838	1 831	n/a
	- in 2013/14	1 778	1 768	1 799	N/A	1 866
Water Rentals	- in 2014/15	113	112	123	124	n/a
	- in 2013/14	112	116	125	N/A	126
F&PP	- in 2014/15	187	179	142	134	n/a
	- in 2013/14	158	166	144	N/A	177
Net Revenue:	- in 2014/15	1 574	1 545	1 573	1 572	n/a
	- in 2013/14	1 508	1 486	1 530	N/A	1 564

Section:	Tab 5: Appendix 5.6 Attachment 4	Page No.:	PUB/MH I-42 b
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation Expense		
Issue:	Changes in 2014 Depreciation Study		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a list of the Canadian electric utilities in other Canadian jurisdictions currently seeking approval for using the ELG procedure.

b) Please indicate the depreciation practices of Ontario-based electric utilities, specifically whether they use ASL or ELG and the extent of componentization for ASL-based utilities.

c) Please file the Gannett Fleming Depreciation Study for Ontario Power Generation Inc. (OPG), including the listing of depreciation accounts.

d) Please describe the process followed by OPG to determine that additional componentization was not required for IFRS compliance.

e) Please indicate whether MH has undertaken the same level of investigation as part of its IFRS conversion activities as OPG. If not, please elaborate.

RATIONALE FOR QUESTION:

To understand the prevalence of the ASL and ELG approaches in Canadian regulated electric utilities.

RESPONSE:

a) Manitoba Hydro and Gannet Fleming are not aware of Canadian electric utilities in other Canadian jurisdictions currently seeking approval to use the ELG procedure. Notably, many utilities applying the ASL method are reporting under US GAAP which has componentization requirements similar to CGAAP.

Please see the response to PUB/MH-I-42b for a listing of North American utilities (including the Regulatory jurisdiction) which have received approval for the use of Equal Life Group (ELG) procedure for rate-setting purpose. Specifically, Gannet Fleming ULC is aware that the following Canadian electric utilities use the ELG procedure:

ATCO Electric
ATCO Gas
Enmax Power Corporation
FortisAlberta Utilities, Inc.
Newfoundland Power Limited
Northland Utilities (NWT) Limited
Northland Utilities (Yellowknife) Limited
Nova Scotia Power, Inc.

b) Manitoba Hydro and Gannett Fleming are aware of the depreciation practices of Ontario Power Generation (OPG) and Hydro One. OPG follows US GAAP using the ASL method and, as demonstrated in the depreciation study included in the response to part c, OPG is more componentized than Manitoba Hydro. In addition, Hydro One follows US GAAP using a vintage based procedure which requires an additional layer of componentization for each installation year within each component.

Manitoba Hydro and Gannett Fleming are not in a position to know the depreciation practices of other Ontario-based electric utilities, specifically whether they use ASL or ELG and the extent of componentization for ASL-based utilities.

c) Please see the attachment to this response for the latest (2013) Gannett Fleming Depreciation Study for Ontario Power Generation Inc.

d) Manitoba Hydro and Gannett Fleming are not aware of the process followed by OPG to determine whether or not additional componentization was required for IFRS compliance. At the time of their last (2013) depreciation study, OPG filed the study consistent with the requirements of US GAAP; compliance with IFRS was not considered as part of that depreciation study.

e) Please see the response to part (d) of this question. Manitoba Hydro's level of investigation into ensuring its asset components are compliant with IFRS has appropriately focussed on assessing its own operations (both past and future) and accounting records, as well as enlisting the services of a depreciation expert from Gannett Fleming to assist with developing the necessary components for compliance with IFRS. Manitoba Hydro also received assistance from KPMG and Ernst & Young with respect to confirming that IFRS has stricter rules with respect to componentization for determining depreciation.

Large utilities are complex organizations that evolve based on the influence of economic, demographic, regulatory, geographic and political impacts specific to their jurisdiction. As such, numerous differences exist between Canadian utilities with respect to the nature, age and condition of their assets, the state of their historical PP&E accounting records, and the influence their respective regulators have had over their accounting/regulatory practices. Although some common depreciation practices exist across the Country, such as the use of the ASL method, the application of these methods can vary across utilities depending on upon their degree of componentization and the how the accounting records are maintained within each component. Generic guidance or studies for componentization and depreciation methods as developed for utilities in one jurisdiction would likely not reflect the circumstances of a particular utility in a different jurisdiction.

Where information is available, Manitoba Hydro has considered the IFRS related changes being made by other utilities in formulating its own policies (e.g. reductions in overhead capitalized). Notably, very few Canadian electric-based utilities have transitioned to IFRS so there is very little audited and confirmed information available from which to compare to. In consideration of Manitoba Hydro's specific circumstances, the adoption of the ELG method of depreciation is the most efficient and best approach for Manitoba Hydro to comply with IFRS. As discussed in Tab 2, page 46, the adoption of the ELG method, in combination with the other accounting changes being made by Manitoba Hydro, including the removal of negative salvage from depreciation rates, is not driving the need for rate increases and as such, there is no benefit to customers of continuing with CGAAP accounting policies for rate-setting purposes upon transition to IFRS.

ONTARIO POWER GENERATION INC.

TORONTO, ONTARIO

ASSESSMENT OF REGULATED ASSET DEPRECIATION RATES AND GENERATING STATION LIVES NOVEMBER 2013

Gannett Fleming

Excellence Delivered ***As Promised***

November 29, 2013

Ontario Power Generation Inc.
700 University Avenue
Toronto, Ontario
M5G1X6

Attention:
Mr. David Bell
Senior Manager, Accounting and Reporting
Ontario Power Generation Inc.

Pursuant to your request, we have conducted a review and assessment of the Regulated Asset Depreciation Rates and Generating Station Lives of Ontario Power Generation Inc. ("OPG"). Our report presents a description of the methods used in the estimation of service life and our recommendations for average service life estimates.

We gratefully acknowledge the assistance of OPG personnel in the completion of the review.

Respectfully submitted,
GANNETT FLEMING CANADA ULC.

LARRY E. KENNEDY
VICE PRESIDENT

LEK/hac
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PART I. INTRODUCTION

ONTARIO POWER GENERATION

ASSESSMENT OF REGULATED ASSET DEPRECIATION RATES AND GENERATING STATION LIVES

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the Gannett Fleming Canada ULC ("Gannett Fleming") review of the Ontario Power Generation Inc. ("OPG" or "the Company") average service life estimates based on December 31, 2012 asset values and for Niagara Tunnel placed in-service in 2013. The average service life estimates recommended in this report are considered in OPG's depreciation review process in establishing the asset depreciation rates and generating station lives for the Property, Plant and Equipment ("PP&E") of OPG's prescribed facilities, including directly assigned corporate PP&E balances. As the depreciation and amortization expense is calculated for revenue requirement purposes, the assets for which average service lives were analyzed include intangible assets.

The facilities for which average service lives were analyzed consist of two nuclear generating stations (Pickering and Darlington) and 54 hydroelectric stations, including six stations (the "previously regulated hydroelectric facilities") that were prescribed by *Ontario Regulation 53/05* under the *Ontario Energy Board Act, 1998* effective 2005 (Sir Adam Beck I, II and the Pump Generating Station; DeCew Falls I and II; R.H. Saunders) and 48 stations (the "newly regulated hydroelectric facilities") that are proposed to be prescribed, as announced by the Government of Ontario in a proposed amendment to *Ontario Regulation 53/05*.[1]

Given the similarity of the plant making up both the previously and newly regulated hydroelectric facilities, the assets of both groups of facilities are categorized by OPG using the same asset classes, with the same average service lives. As part of this study, Gannett Fleming specifically reviewed the operating considerations and typical station configurations of the newly regulated hydroelectric facilities in order to determine if this approach is reasonable, or if there is a need for additional componentization or changes to average service lives specific to these facilities. This review included site tours of 16 newly regulated facilities and operational staff discussions.

REPORT STRUCTURE

Part I, Introduction, contains statements with respect to the scope and plan of the report and the basis of the study. Part II, Methods Used in the Estimation of Average Service Life, presents the methods used in the estimation of average service lives. Part III, Results of Study, presents a summary of the service life estimates and the comparable peer data used in the development of the average service life estimates. Schedule 1A of this report summarize the average service life estimates for the accounts making up the previously and newly regulated hydroelectric facilities. Schedule 1B of this report summarizes the average service life estimates for all

[1] Notice of proposed amendment can be found in OPG's application to the Ontario Energy Board for new payment amounts under EB-2013-0321 Ex. A1-6-1, Attachment 3.

accounts of the prescribed nuclear assets and also separates the nuclear Asset Retirement Costs ("ARC"), which are depreciated over station lives.

BASIS OF THE STUDY

Background. In March 2007, Gannett Fleming submitted a report titled "Review of the Ontario Power Generation Inc. Depreciation Review Process" (the "2007 Report"). The 2007 Report presented a summary of the findings of an independent review of the processes, procedures and methods used by OPG to review its depreciation expense. The 2007 Report indicated that "Gannett Fleming has found that the processes, procedures and methods followed by Ontario Power Generation Inc. adequately meet regulatory objectives regarding depreciation generally accepted by Canadian regulatory authorities."[2] Additionally, Gannett Fleming found that "OPG's current Depreciation Review Process results in the depreciation expense component of the revenue requirement that reasonably and appropriately reflects the consumption of the average service life of OPG's regulated assets. Gannett Fleming also views that, overall, the DRC process is adequate in meeting the generally accepted regulatory objectives regarding depreciation for regulated North American utilities."[3] Overall, the 2007 Report concluded that the procedural foundation upon which OPG's Depreciation Review Committee ("DRC") has developed average service life estimates is robust and appropriate. The 2007 Report contributed, in part, to the Ontario Energy Board ("OEB") Decision EB-2007-0905 finding that the approach employed by OPG in the development of its depreciation expenses is reasonable.

[2] Cover Letter to the 2007 Report.
[3] 2007 Report, page III-2.

In 2011, Gannett Fleming was retained by OPG to complete a comprehensive assessment of the asset depreciation rates and generating station lives of OPG's regulated assets as of December 31, 2010. As noted in the report titled "Assessment of Regulated Asset Depreciation Rates and Generating Station Lives" dated December 16, 2011 (the "2011 Depreciation Study"), the DRC had continued to follow the methods as outlined in the 2007 Report in the four years since the issuance of that report. Furthermore, Gannett Fleming found that OPG had modified and adapted its processes to address the key recommendations in the 2007 Report. As such, Gannett Fleming viewed that the then currently approved average service life estimates continued to be based on a procedurally sound and reasonable DRC process. In light of this, Gannett Fleming found much of the work prepared by the DRC over the preceding several years to be a reliable information source in the course of conducting the 2011 Depreciation Study. The 2011 Depreciation Study recommended the continuation of the currently approved average service life estimates for all plant accounts for OPG's regulated assets, with three modifications to the average service life estimates to the hydroelectric accounts, including the creation of a new plant account for security systems. OPG implemented these modifications for all of its hydroelectric operations effective January 1, 2012.

The 2011 Depreciation Study also recommended the continuation of the then current life span dates for the regulated stations, including the Pickering A and Pickering B nuclear units (now more generally described as Pickering to reflect the consolidation of the units into a single station), pending the technical results of a pressure tube study. Specifically, Gannett Fleming noted the following: "Gannett Fleming believes that until the review of the Pickering B plant is completed it is premature to adjust the life span date of Pickering A from the current date of December 31, 2021. Gannett Fleming also believes that the use of a life span of September 30, 2014 for Pickering B is appropriate until such time as reviews to determine the economic feasibility of a major pressure tube program are completed, which Gannett Fleming understands is expected in 2012. In the circumstance that the assessment of the condition of the Pickering pressure tubes results in a decision that the Pickering plant cannot continue operations, future depreciation reviews may be required to adjust the life span date of the Pickering A units."[4]

As anticipated in the 2011 Depreciation Study, the results of the work program related to the Pickering B (now known as Pickering Units 5 through 8) pressure tubes confirmed in 2012 that these units could operate beyond September 30, 2014. In addition, the Niagara Tunnel, which represents a significant new addition to the PP&E of OPG's regulated assets, was placed in-service in 2013, and 48 additional OPG hydroelectric facilities are proposed to become subject to OEB regulation. In light of these developments, OPG issued a Request for Proposal in 2013 for a new independent depreciation study. Gannett Fleming was retained to provide an independent professional opinion regarding the average service life estimates used by OPG for the previously and newly regulated assets, leading to the recommendations and conclusions as contained in this report. Gannett Fleming used a similar approach to the 2011 Depreciation Study in arriving at these recommendations and conclusions.

The DRC has continued to follow the methods outlined in the 2007 Report,

[4] 2011 Depreciation Study, page II-12.

having modified and adapted its processes to address key recommendations in that report. As such, the currently approved average service life estimates, as modified by the results of the 2011 Depreciation Study, continue to be based on a procedurally sound and reasonable DRC process. Given this previously-reviewed DRC process, the prior Gannett Fleming findings regarding this process, and the review of the DRC work by Gannett Fleming as part of the 2011 Depreciation Study, Gannett Fleming, to a large extent, continues to find the work prepared over the past several years by the DRC to be a reliable information source. While the 2007 Report and the 2011 Depreciation Study were focused on the prescribed facilities, OPG's internal DRC review process applies to all of OPG's hydroelectric facilities, including the newly regulated hydroelectric plants. In light of this and given the similarity of plant assets and asset management programs across OPG's hydroelectric fleet, Gannett Fleming also finds the DRC work to be, to a large extent, a reliable source of information for the newly regulated hydroelectric facilities.

With the exception of minor fixed assets, which represent approximately 2% of OPG's total regulated investment excluding ARC, OPG continues to depreciate its regulated assets using a straight line method of depreciation, with the depreciation rates being calculated based on the Average Life Group – Whole Life Procedure. The Average Life Group – Whole Life procedure has been used by OPG for a number of years and has previously been approved by the OEB.

Service Life Estimates. The service life estimates presented herein are based on commonly accepted methods and procedures for determining average service life estimates for electric utility plant, and consideration of information obtained about condition assessments through discussion with OPG operating staff and site tours. The service life estimates were based on in-service asset values through December 31, 2012 (with the exception of the Niagara Tunnel which was placed in-service in 2013), a review of the Company's practices and outlook as they relate to plant operation and retirement, and the service life estimates for other electric generation companies.

The average service life estimates for each depreciable group were reviewed based on the professional judgment of Gannett Fleming. In reviewing the average service lives, Gannett Fleming gave consideration to the average service lives currently approved for use by OPG; the results of the 2011 Depreciation Study; the approved service life estimates for a peer group of electric generation companies; the experience of internal OPG operating and management staff; assessment of asset conditions; and the experience of Gannett Fleming in selecting average service lives for similar plant. Gannett Fleming's review of the average service lives for the Niagara Tunnel is discussed specifically in Part II of this report.

Depreciation Policy. In the review of OPG's plant account structure, Gannett Fleming considered the expectation of the diversity of asset retirement ages within each account in the development of the average service life estimate for each account. The use of the Average Life Group - Whole Life Procedure applies the same annual accrual rate to all vintages of plant, which is calculated by dividing 100% by the average service life estimate. As such, a common life estimate is applied to each of the asset vintages, and each of the assets within each vintage. This procedure is widely used by a number of regulated electric utilities throughout North America, and results in a reasonable recovery of capital investment.

Depreciation related to the nuclear asset classes continues to be based on the lesser of the generation station life or asset class life. Hydroelectric generating stations' lives, including those of the newly regulated hydroelectric stations, are considered to be limited by the service lives of the dams; however, since the dams have service lives that exceed those of most other asset classes, Gannett Fleming is of the view that they are not a significant limiting factor at this time.

As discussed later in this report, based on its review, Gannett Fleming has recommended that two new hydroelectric plant accounts and two new nuclear plant accounts be created in order to separate certain assets currently recorded in other accounts. Gannett Fleming also understands that, for ease of future average service life reviews, the DRC is considering a recommendation for a disaggregation of Account 15340000 – Nuclear Process Systems into separate, new plant accounts for major types of systems. The new accounts would have the same average service life of 55 years as Account 15340000. Gannett Fleming agrees with this approach, as it would facilitate future service life reviews.

RECOMMENDATIONS

The average service life estimates set forth herein apply specifically to the PP&E (including intangible assets) of OPG's previously and newly regulated hydroelectric facilities and prescribed nuclear facilities, including directly assigned corporate PP&E, as of December 31, 2012 and the Niagara Tunnel placed in-service in 2013. The average service life recommendations contained in this report should be applied to all assets within each group of assets. As described in the Results section of this report, Gannett Fleming is recommending six changes to the average service life estimates, as follows:

- Account 10318000 – Hydroelectric – Gates, Stoplogs and Operating Mechanisms – Change average service life estimate from the currently approved 50 years to 55 years;
- New Account – Hydroelectric – Roofing – Create a new plant account with an average service life estimate of 30 years;
- New Account – Hydroelectric – Fencing – Create a new plant account with an average service life estimate of 25 years;
- New Account – Nuclear – Roofing – Create a new plant account with an average service life estimate of 25 years;
- New Account – Nuclear – Large Circulating Water Motors (greater than 200Hp) – Create a new plant account with an average service life estimate of 30 years; and
- Reclassification of assets for nuclear turbine generator controls from existing Account 15411100 – Turbines and Auxiliaries with a 55-year average service life to existing Account 15600000 – Nuclear – Instrumentation and Control with a 15-year average service life.

Gannett Fleming is also of the view that, as recommended by the DRC in 2012, a new hydroelectric plant account with an average service life estimate of 90 years should be established for the tunnel lining of the new Niagara Tunnel.

Continued surveillance and periodic revisions are required to maintain use of appropriate average service lives and depreciation rates. Each account should be subjected to a complete depreciation study which re-evaluates its average service life estimates periodically. Gannett Fleming notes that the practice of OPG to review its various asset accounts and depreciation service lives over an approximate five-year cycle meets this common depreciation practice.

PART II. METHODS USED IN THE ESTIMATION OF AVERAGE SERVICE LIFE

PART II. METHODS USED IN THE ESTIMATION OF AVERAGE SERVICE LIFE

DEPRECIATION

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric generation plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy and obsolescence.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight Line method of depreciation.

As described in earlier sections of this report, the recommendations of this report are to continue to incorporate the depreciation practices historically used at OPG, namely that the depreciation expense be calculated in accordance with the Straight Line method of depreciation, incorporating the Average Life Group - Whole Life procedure in the calculation of the depreciation rate. The calculation of annual depreciation expense based on the Straight Line - Average Life Group - Whole Life procedure requires the estimation of average life as discussed in the sections that follow.

AVERAGE SERVICE LIFE

The use of an average service life for property groups that include large numbers of similar assets implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a life estimate that considers the retirements of units which survive at successive ages. The average service life estimates reviewed by Gannett Fleming were based on judgment which considered a number of factors, including:

- Understanding of the processes used in the development of the currently used average service life estimates through the completion of a prior review of the DRC process filed in EB-2007-0905, and through the completion of the 2011 Depreciation Study;
- Understanding of the assets currently in service through discussions with company staff, including representatives of the nuclear and hydroelectric generation operating units;
- Physical site tours of nuclear and newly regulated hydroelectric generation sites;
- Review of current accounting practices and procedures applied and their consistency with those in place during the review submitted in EB-2007-0905 and those reflected in the 2011 Depreciation Study;
- Review of analyses provided to DRC;
- Average service life estimates from other peer electric generation companies; and,
- The general experience and professional judgment of Gannett Fleming.

Prior Assignments and Review of the DRC Process. Gannett Fleming had been previously retained in 2007 to review the practices and procedures used by the DRC in the completion of prior depreciation studies, and, in 2011, for the completion of a full depreciation study. The 2007 review resulted in a report of the findings of Gannett Fleming which were submitted to the management of OPG in 2007. The 2011 Depreciation Study resulted in a report dated December 16, 2011, which was submitted to management of OPG in 2011 and, in 2013, filed by OPG in OEB proceeding EB-2013-0321. These prior reviews provided Gannett Fleming with an understanding of the processes used by OPG in the determination of average service life estimates, a general understanding of the type of generation plant in service at OPG, and an understanding of the regulatory oversight of the Ontario Energy Board.

Operating Discussions and Site Tours. Discussions with operating representatives and the physical site tours undertaken by Gannett Fleming provided Gannett Fleming with an understanding of the type of assets in service for both nuclear and hydroelectric service. The site tours provide Gannett Fleming with the necessary background to make an assessment of the physical installations of the OPG plant, and to understand the type of plant in service and the operating conditions of the facilities. The operating interviews are undertaken to understand the historic operating conditions that have led to retirement of plant in the past and to understand the current condition of the assets which may impact future retirement plans. The operating interviews were conducted both during the Gannett Fleming tours of the physical facilities and immediately following the tours, and again after Gannett Fleming completed an initial analysis of the average service life expectations.

In conducting the 2011 Depreciation Study, Gannett Fleming toured the following generation sites:

- R.H. Saunders Hydroelectric Generating Station;
- Sir Adam Beck I Hydroelectric Generating Station;
- Sir Adam Beck II Hydroelectric Generating Station; and
- Darlington Nuclear Generating Station.

The scope of this report includes the review of the newly regulated hydroelectric generation plants. In order to gain a better understanding of these assets and as part of the assessment of nuclear assets, Gannett Fleming toured the generation plants listed below in the course of this assignment. Gannett Fleming toured a total of 16 newly regulated hydroelectric facilities, representing a range of different types and sizes of the facilities.

- Chats Falls Hydroelectric Generating Station;
- Arnprior Hydroelectric Generating Station;
- Stewartville Hydroelectric Generating Station;
- Calabogie Hydroelectric Generating Station;
- Barrett Chute Hydroelectric Generating Station;
- Chenaux Hydroelectric Generating Station;
- Des Joachims Hydroelectric Generating Station;
- Otto Holden Hydroelectric Generating Station;

- Bingham Chutte Hydroelectric Generating Station;
- Big Chute Hydroelectric Generating Station;
- Ragged Rapids Hydroelectric Generating Station;
- Hanna Chute Hydroelectric Generating Station;
- South Falls Hydroelectric Generating Station;
- Elliot Chute Hydroelectric Generating Station;
- Tretheway Falls Hydroelectric Generating Station;
- Big Eddy Hydroelectric Generating Station;
- Darlington Nuclear Generating Station; and
- Pickering Nuclear Generating Station.

Tours of the above generating stations provided Gannett Fleming with the necessary background to complete this assignment. During and immediately following each of the above site tours, interviews of the operational representatives were undertaken by Gannett Fleming. These interviews were conducted at the time of the site tours and covered the following topics, including, where applicable, inquiries regarding operational or other changes since the 2011 Depreciation Study:

- Operating history of both the plant being toured and of other similar plant not toured;
- Replacement history of major plant components and review of significant retirement programs;
- General operating experience of the major plant components;
- Review of any life restricting operational issues;

- Review of any issues that have emerged during the DRC process;
- Review of changes where advancements in technology may cause changes to average service life indications; and
- Discussions of the manner in which OPG's hydroelectric plants may be different than other peer hydroelectric generation plants.

In addition, following the plant tours, discussions were conducted through a number of telephone interviews held between Gannett Fleming and operational representatives of OPG.

Review of Accounting Policies. Gannett Fleming had discussions with management representatives during prior assignments to understand OPG's depreciation and accounting policies and practices. As part of the current assignment, Gannett Fleming confirmed with management representatives whether there had been changes to these policies and practices since the 2011 Depreciation Study and whether these policies and practices are also applied to the newly regulated hydroelectric plant.

An understanding of the accounting policies is required to:

- Understand the accounting entries associated with the retirement of plant. In particular, Gannett Fleming required an understanding of the accounting entries associated with gains and losses on retirement;
- Understand any thresholds or policies with regard to capitalization of major component as compared to the replacement of minor components of plant through operating and maintenance budgets; and

- Determine if a review of the adequacy of the accumulated depreciation reserve is required.

Gannett Fleming notes that, notwithstanding OPG's of adoption of US GAAP, the current DRC and depreciation policies and practices for the previously regulated assets are the same as those reflected in the 2011 Depreciation Study. Gannett Fleming also notes that starting in 2011, all gains and losses on retirement transactions are booked by OPG for all of its assets to the income statement in the year of the retirement transaction. In this manner, the accumulated depreciation account does not include embedded gains or losses from previous retirement transactions. Gannett Fleming understands that, on an OPG-wide basis, the total cumulative undepreciated value of embedded past losses, which OPG removed from the net book value of fixed and intangible assets in 2011, is less than $1M.

Gannett Fleming also notes that any amount of cost of removal (that is not associated with the retirement of an asset for which an Asset Retirement Obligation ["ARO"] is established) is charged directly to the income statement in the year of the transaction. Both the recording of gains and losses to income and the charging of cost of removal to income is in accordance with the provisions of US GAAP. As previously noted in the 2011 Depreciation Study (page II-7), while these are not the traditional practices of regulated utilities, Gannett Fleming believes that the nature of the large plant components and small amount of retirement transactions make this policy viable and reasonable for OPG. Additionally, because the accumulated depreciation account does not include adjustments for past retirement transactions the need to test the adequacy of the accumulated depreciation accounts is eliminated.

Gannett Fleming confirmed that the same DRC and depreciation policies and practices are applied by OPG both to the previously and newly regulated hydroelectric assets.

Analysis and Results of DRC Reviews. OPG is the world's largest operator of CANada Deuterium Uranium ("CANDU") nuclear units, has some of the oldest CANDU units, and has the most extensive operational knowledge of all CANDU operators in the world. OPG is heavily involved in technical exchanges with other CANDU operators, and closely monitors equipment degradation issues in order to assess potential impacts on OPG's units. OPG is often the "lead" utility in terms of the knowledge of degradation issues, which may impact unit and component lives. In the particular circumstance of the CANDU nuclear installations, OPG internal staff is recognized as experts in the technology.

The DRC has continued to complete detailed reviews of the average service life expectations for OPG's plant accounts. The DRC's technical reviews are conducted by internal and external experts in the specific areas associated with a number of accounts. As indicated above, the OPG operational staff is considered to be the world experts in the operational aspects of the CANDU units. As part of the current assignment and the 2011 Depreciation Study, Gannett Fleming reviewed these analyses which provided a significant background on the physical condition of the assets, a meaningful history of the manner in which plant assets have provided electric generation service over the past many years, and identified major upcoming replacement or retirement programs.

Peer Analysis. In order to provide a comparison for each account grouping, Gannett Fleming selected a peer group of companies to use in the development of average service lives. The companies selected for comparison were all companies for which Gannett Fleming has recently completed depreciation studies relating to Canadian electric generation plants. As such, Gannett Fleming is able to make a meaningful comparison giving consideration to factors such as capitalization and retirement policies, maintenance practices, and general operational practices. The companies selected for comparison were:

- BC Hydro;
- Manitoba Hydro;
- New Brunswick Power;
- Newfoundland and Labrador Power Corporation (Nalcor);
- Northwest Territories Power Corporation; and
- SaskPower.

As noted in the 2011 Depreciation Study (page II-8), asset service lives for OPG's hydroelectric asset classes lend themselves to comparison with other utilities due to the similar nature of the technology used in hydroelectric energy production. This applies both to the previously and newly regulated hydroelectric assets. As such, the above utilities provided Gannett Fleming with a comparable base of average service life estimates to use in the development of the service life estimates for OPG's hydroelectric asset classes.

Professional Judgment. The use of professional judgment in the development of average service life estimates is a practice that is appropriate and has been used for many years before North American regulatory jurisdictions. When available, the use of statistical analysis of the historic retirement transactions combined with the use of professional judgment which includes the physical site inspections, review of accounting procedures and practices, use of operational staff interviews, review of prior studies, and review of the approved life estimates of peer companies, provides the most complete method of service life analysis. However, the use of professional judgment alone also provides an appropriate basis for developing average service life estimates, when appropriate factors are considered, and has been accepted as a valuable depreciation analysis tool in many North American jurisdictions.

In the specific circumstances of the OPG average service life estimation, the volume of historic retirement transactions available to be analyzed is not sufficient to undertake a detailed study of retirement history. As such, a retirement rate analysis was not completed by Gannett Fleming. However, all of the remaining life estimation tools were available and were used to develop appropriate average service life estimates.

Life Span Dates. Life expectancy of electric generation plant assets is impacted not only by physical wear and tear of the assets but also by economic factors including the feasibility of the economic replacement of major operating components or the economic viability of the plant as a whole. In circumstances where the replacement of major operating components is not economically feasible, the life of the major component can be the determining factor of the generation plant and all of the assets within the plant. As such, the remaining depreciation life of electric generation plant assets is the lesser of the physical life expectation of the asset or the period to the end of the life span of the generation plant.

The use of life span dates for determining depreciable lives for regulated electric generation plant is common throughout many North American regulatory jurisdictions. The basis for the determination of the life span date is usually based on one or more of the following:

- the physical life estimation of the major and vital components of the generating plant;
- the duration of operating licenses;
- precedent and policy of the regulatory jurisdiction;
- expiration of the supply source for which the generation plant is dependent; and
- expiration of market demand upon which the generation plant is dependent.

In prior depreciation reviews, OPG has determined a life span date for each of the prescribed nuclear plants. The life span dates have been determined through a review of the expected life of the significant components at each nuclear site. Additionally, the life span dates historically have been influenced by the period through to any required major site refurbishment, as the continued operation of the plant is dependent upon the ability to economically refurbish the plant for continued use. It is the experience of Gannett Fleming that the depreciation schedules for most North American nuclear generation plants are dependent upon appropriately developed life span dates. It continues to be the view of Gannett Fleming that the use of life span dates is appropriate for the OPG nuclear generation plants.

In the 2011 Depreciation Study, it was noted that an assessment of the condition of the Pickering Units 5 through 8 (formerly Pickering B) pressure tubes was underway at that time. In that report, Gannett Fleming noted that the use of a life span date of September 30, 2014 for Pickering Units 5 through 8 was appropriate until such time as reviews to determine the economic feasibility of a major pressure tube program are completed, which was expected to occur in 2012. It was also noted that the operation of Pickering Units 1 and 4 (formerly Pickering A) requires the joint operation of certain components of both sets of units. As such, both physical and economic considerations may result in the circumstance that should Pickering Units 5 through 8 be shut down before Pickering Units 1 and 4, there is a significant likelihood that the operation of Pickering Units 1 and 4 would not be viable following the shutdown. At that time, Gannett Fleming was of the view that until the review of pressure tubes at Pickering Units 5 through 8 was sufficiently complete, it was premature to adjust the life span date of Pickering Units 1 and 4 from the then current date of December 31, 2021.

In 2012, the DRC considered the impact of the results of the substantial completion in 2012 of the work program necessary to determine the feasibility of achieving extended service lives of the pressure tubes at Pickering. Upon receiving confirmation that the work program indicated high confidence that the operation of the pressure tubes at Pickering Units 5 through 8 could be extended, the DRC concluded that the following dates, which were reflected in materials submitted by OPG in OEB proceeding EB-2012-0002, appropriately recognize the expected average life spans of the nuclear stations, for depreciation purposes, effective December 31, 2012:

- Pickering Units 1 and 4 (formerly Pickering A) – December 31, 2020; and
- Pickering Units 5 through 8 (formerly Pickering B) – April 30, 2020.

The above station life span dates reflect the following expected life span dates for the individual Pickering units:

- Units 1, 4, 7 and 8 – Q4 2020
- Unit 5 – Q1 2020
- Unit 6 – Q2 2019

The life span dates for Pickering Units 1 and 4 were aligned with the last two units of Pickering Units 5 through 8 in recognition of the technical and economic considerations that likely would have prevailed against the operation of Units 1 and 4 in the absence of continued operation of at least two units of Pickering Units 5 through 8.

Gannett Fleming has reviewed the DRC's analysis in establishing the above station and unit life span dates and has concluded that they are reasonable for use in this study. Gannett Fleming is also of the view that the factors considered and methods used by the DRC in the assessment of life span dates remain appropriate and consistent with common regulatory practices and should continue to be used in future reviews.

As recognized in the previous DRC reviews and the 2011 Depreciation Study, a major refurbishment program is expected to be undertaken at the Darlington nuclear site. This continues to be reflected in the life span date of December 31, 2051 for the Darlington station. Given that the major operating components at the Darlington plant are expected to be refurbished in the near future, Gannett Fleming finds that the

December 31, 2051 date continues to be reasonable, as recommended in the 2012 DRC review.

The previously and newly regulated hydroelectric plant dams are considered to be the life-limiting component of these stations, but since the dams have service lives that exceed that of most other classes, Gannett Fleming is of the view that they are not a significant limiting factor.

Niagara Tunnel. In March 2013, the Niagara Tunnel Project was placed in-service. The scope of the project included the design, construction and commissioning of a new, 10.2 kilometer long diversion tunnel from a new intake under the existing International Niagara Tunnel Works structure in the upper Niagara River above Niagara Falls to a new outlet canal feeding into the existing Sir Adam Beck ("SAB") Pump Generating Station canal. This tunnel supplements the diversion capacity of the two existing tunnels that bring water from the Niagara Falls to the SAB stations, and therefore enables additional generation from these facilities. The new diversion tunnel and related works were delivered under a Design-Build Agreement between OPG and its main contractor.

The new tunnel was constructed using a two-pass tunneling system, with the initial pass consisting of the excavation of the tunnel using a tunnel boring machine and the installation of the initial lining using steel supports in the tunnel roof and a full circumference layer of shortcrete (sprayed concrete). The permanent lining comprised of an impermeable membrane generally surrounding un-reinforced concrete locked in place by cement grout was installed as part of the second pass.

The Niagara Tunnel is a significant investment of approximately $1.5 billion in OPG's rate base. This cost largely related to the tunneling activity (approximately $900 million) and to the installation of the tunnel lining (approximately $375 million)[5]. The life expectation of the investment associated with the tunneling is considered to be the same as the life expectations of the two existing tunnels at the Niagara Falls. As such the investment associated with the tunneling for the project has been grouped with the investment associated with the existing tunnels. Gannett Fleming agrees with this treatment. The material and installation techniques used for the lining of the new tunnel are significantly different than the linings of the existing two tunnels. Based on its review of the technical specifications and requirements for the new tunnel as well as other documentation and discussions, Gannett Fleming supports the recommendation of the 2012 OPG DRC that a longer service life of 90 years (as compared to the 75-year life applied to the lining material in the existing tunnels) be used for the investment specific to the tunnel lining of the new tunnel. A further discussion of the recommended service life for the new tunnel lining is found in Appendix 1.

[5] Amounts are for the Niagara Tunnel addition placed in-service in March 2013.

PART III. RESULTS OF STUDY

PART III. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The review of the reasonableness, and recommended alternative average service life estimates related to plant in service as of December 31, 2012 and the Niagara Tunnel placed in service in 2013 is the principal result of the study. Continued surveillance and periodic revisions are required to maintain continued use of appropriate average service lives. An assumption that life estimates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and for the change of the composition of property in service.

SUMMARY OF RESULTS

Gannett Fleming has reviewed the life span dates and average service life estimates for all regulated generation plants and asset categories, considering the factors as identified in Part II of this report. While this review included an analysis of all asset categories, additional focus was placed on the investment categories that comprise the majority of the plant in service.

Gannett Fleming recommends the use of the life span dates as discussed in Part II of this report. Furthermore, Gannett Fleming recommends the continued use of the currently approved average service life estimates, as modified for the results of the 2011 Depreciation Study, for all accounts with the following exceptions:

- <u>Account 10318000 – Hydroelectric Head Gates, Stoplogs and Operating Mechanisms</u> – Average service life to be changed from the currently approved 50 years to 55 years;

- New Account – Hydroelectric – Roofing – Create a new plant account with a 30-year average service life to separate roofing from other plant accounts;
- New Account – Hydroelectric – Fencing – Create a new plant account with a 25-year average service life to separate fencing from other plant accounts;
- New Account – Nuclear – Roofing – Create a new plant account with a 25-year average service life to separate roofing from other plant accounts;
- New Account – Nuclear – Large Circulating Water Motors – Create a new plant account with a 30-year average service life to separate large motors (greater than 200 Hp) from other plant accounts; and
- Reclassification Between Accounts – Nuclear –Turbine Generator Controls – Reclassify nuclear turbine generator controls from Account 15411100 – Nuclear – Turbines and Auxiliaries with a 55-year average service life to Account 15600000 – Nuclear – Instrumentation and Control with a 15-year average service life.

The above recommendations for the hydroelectric plant accounts apply both to the previously and newly regulated hydroelectric assets. Gannett Fleming also agrees with the 2012 DRC recommendation that a new, separate hydroelectric plant account with an average service life estimate of 90 years be established for the tunnel lining of the new Niagara Tunnel placed in service in 2013.

A detailed discussion of the reasons and factors considered leading to the recommended changes for the above accounts is provided in Appendix 1 to this report.

Additionally, Gannett Fleming is satisfied that it is appropriate for OPG to categorize the assets making up both the previously and newly regulated hydroelectric facilities into the same plant accounts, with the same average service lives. In order for this approach to remain reasonable over time, future reviews of asset service lives for the hydroelectric plant accounts should continue to consider whether the conclusions of such reviews and the underlying analysis are applicable to both groups of assets.

DESCRIPTION OF APPENDICES

Appendix 1 to this report provides a summary of the factors considered in the review of each of the major accounts in which Gannett Fleming is recommending a change, as well as the lining of the new Niagara Tunnel. While Gannett Fleming reviewed all accounts listed in Schedule 1A and Schedule 1B, Appendix 1 only provides detailed analyses of the accounts in which a change to the average service life estimate is recommended, as well as the lining of the new Niagara Tunnel.

Appendix 2 to this report provides a listing of the newly regulated hydroelectric stations.

ONTARIO POWER GENERATION

SCHEDULE 1A - SUMMARY OF THE CURRENT AVERAGE SERVICE LIFE ESTIMATES AND GANNETT FLEMING RECOMMENDED AVERAGE SERVICE LIFE ESTIMATES

PREVIOUSLY AND NEWLY REGULATED HYDROELECTRIC ASSETS AS AT DECEMBER 31, 2012

ASSET CLASS #	DESCRIPTION		NBV	% AGE	CURRENT	RECOMMENDED
10200000	HYDROELECTRIC - SUBSTRUCTURES AND SUPERSTRUCTURES	$	1,227,972,792	19.79%	100	100
10101000	HYDROELECTRIC - EXCAVATION, DREDGING, RIPRAPPING AND GROUTING	$	1,380,649,053	22.25%	100	100
10312000	HYDROELECTRIC - DAMS - CONCRETE	$	991,676,359	15.98%	100	100
10318000	HYDROELECTRIC - GATES, STOPLOGS AND OPERATING MECHANISMS	$	361,275,033	5.82%	50	55
10306000	HYDROELECTRIC - SURGETANK, PIPELINE, CONDUIT, PENTSTOCK	$	292,982,384	4.72%	75	75
10400000	HYDROELECTRIC - TURBINES AND GOVERNORS	$	213,248,856	3.44%	70	70
10501000	HYDROELECTRIC - MAIN ROTATIONAL ELECTRICAL EQUIPMENT - LESS WINDINGS	$	221,787,828	3.57%	75	75
10301000	HYDROELECTRIC - LINING OF TUNNELS AND PERMANENT SHAFTS	$	219,912,108	3.54%	75	75
10510000	HYDROELECTRIC - MAIN POWER AND STATION SERVICE - TRANSMISSION	$	175,590,706	2.83%	50	50
10500000	HYDROELECTRIC - MAIN ROTATIONAL ELECTRICAL EQUIPMENT - WINDINGS	$	114,912,729	1.85%	40	40
10311000	HYDROELECTRIC - DAMS - EARTH AND ROCKFILL	$	106,329,529	1.71%	100	100
10405000	HYDROELECTRIC - TURBINE RUNNERS	$	96,535,236	1.56%	40	40
10210000	HYDROELECTRIC - SERVICE AND EQUIPMENT BUILDINGS	$	101,137,556	1.63%	55	55
10502000	HYDROELECTRIC - BUS, SWITCHING AND POWER CABLE	$	85,327,386	1.37%	45	45
10300000	HYDROELECTRIC - CANAL, FOREBAY, RETAINING WALL LINING	$	83,670,918	1.35%	75	75
10504000	HYDROELECTRIC - CONTROL BOARDS AND SWITCHBOARDS	$	77,122,794	1.24%	25	25
10700000	HYDROELECTRIC - AUXILIARY SYSTEMS	$	72,291,792	1.16%	30	30
10302000	HYDROELECTRIC - SPILLWAYS, SLUICES, FLUMES	$	72,513,556	1.17%	75	75
10100000	HYDROELECTRIC - LAND	$	37,317,826	0.60%	100	100
10709000	HYDROELECTRIC - OWNED BRIDGES, RAILWAY TRACK, WHARVES	$	54,666,182	0.88%	65	65
10505000	HYDROELECTRIC - STATION SERVICE ELECTRICAL EQUIPMENT	$	44,045,969	0.71%	50	50
10601000	HYDROELECTRIC - MECHANICAL EQUIPMENT - CRANES AND FOLLOWERS	$	45,064,408	0.73%	55	55
10205000	HYDROELECTRIC - OUTDOOR STRUCTURES	$	20,878,634	0.34%	75	75
10710000	HYDROELECTRIC - FIRE PROTECTION SYSTEMS	$	27,019,773	0.44%	20	20
10503000	HYDROELECTRIC - HIGH VOLTAGE SWITCHING	$	16,335,367	0.26%	40	40
10503100	HYDROELECTRIC - REVENUE METERING - HIGH VOLTAGE SWITCHING, CONTROL BOARDS AND SWITCHBC	$	13,162,790	0.21%	30	30
10311100	HYDROELECTRIC - DAMS - TIMBER CRIB	$	8,624,328	0.14%	60	60
16210000	ADMINISTRATION AND SERVICE BUILDINGS - PERMANENT BLDGS. ROADS AND SITE IMPROVEMENT	$	7,852,168	0.13%	50	50
10991000	HYDROELECTRIC - MAJOR SPARES	$	7,207,631	0.12%	100	100
10315000	HYDROELECTRIC - STEEL RACKS	$	6,220,914	0.10%	40	40
10302100	HYDROELECTRIC - PUBLIC SAFETY/WARNING BOOMS	$	4,066,117	0.07%	15	15
16550000	ADMINISTRATION AND SERVICE BUILDINGS - LAN CABLE	$	3,922,188	0.06%	10	10
10531000	HYDROELECTRIC - CIRCUIT BREAKERS	$	4,048,211	0.07%	50	50
10720000	HYDROELECTRIC - SECURITY SYSTEMS	$	1,987,371	0.03%	10	10
16100000	ADMINISTRATION AND SERVICE BUILDINGS - LANDS	$	591,758	0.01%	N/A	N/A
16560100	ADMINISTRATION AND SERVICE BUILDINGS - ADMINSTRATIVE SYSTEMS SW	$	830,257	0.01%	5	5
16230000	ADMINISTRATION AND SERVICE BUILDINGS - FRAME & METAL	$	11,000	0.00%	25	25
18400000	COMMUNICATIONS - POWER LINE EQUIPMENT	$	591,742	0.01%	15	15
18460000	COMMUNICATIONS - DATA ACQ. EQUIP., MAN MACHINE INTERFACE EQUIPMENT	$	105,828	0.00%	15	15
18630000	COMMUNICATIONS - OPTICAL WIRE	$	644,287	0.01%	25	25
16551000	ADMINISTRATION AND SERVICE BUILDINGS - LAN ELECTRICAL CONNECTING DEVICES	$	777,362	0.01%	5	5
18633000	COMMUNICATIONS - OPTICAL WIRE - REVENUE METERING	$	715,860	0.01%	30	30
18540000	COMMUNICATIONS - ADMINISTRATIVE TELEPHONE EQUIPMENT	$	216,553	0.00%	7	7

ONTARIO POWER GENERATION

SCHEDULE 1A - SUMMARY OF THE CURRENT AVERAGE SERVICE LIFE ESTIMATES AND GANNETT FLEMING RECOMMENDED AVERAGE SERVICE LIFE ESTIMATES
PREVIOUSLY AND NEWLY REGULATED HYDROELECTRIC ASSETS AS AT DECEMBER 31, 2012

ASSET CLASS #	DESCRIPTION	NBV	% AGE	CURRENT	RECOMMENDED
18600000	COMMUNICATIONS - WOOD POLE, COMMUNICATION CABLE APPARATUS AND BOOTHS	$ 77,039	0.00%	40	40
18530000	COMMUNICATIONS - TIMBER AND STEEL STRUCTURES	$ 17,738	0.00%	40	40
18100000	COMMUNICATIONS - LAND	$ 879	0.00%	100	100
16630000	ADMINSITRATION AND SERVICE BUILDINGS - SYSTEMS & EQUIPMENT	$ 132,754	0.00%	20	20
18200000	COMMUNICATIONS - BUILDINGS	$ 58,601	0.00%	50	50
18500000	COMMUNICATIONS - RADIO EQUIPMENT	$ 5,974	0.00%	15	15
	MINOR FIXED ASSETS	$ 4,094,653	0.07%		
NEW	HYDROELECTRIC - NIAGARA FALLS - NEW TUNNEL LINING	$ -	0.00%	N/A	90
NEW	HYDROELECTRIC - BUILDINGS - ROOFING	$ -	0.00%	N/A	30
NEW	HYDROELECTRIC - FENCING	$ -	0.00%	N/A	25
	GRAND TOTAL	**$ 6,206,228,777**	**100.00%**		

ONTARIO POWER GENERATION

SCHEDULE 1B. SUMMARY OF CURRENT AVERAGE SERVICE LIFE ESTIMATES AND GANNETT FLEMING RECOMMENDED AVERAGE SERVICE LIFE ESTIMATES
PRESCRIBED NUCLEAR ASSETS AS AT DECEMBER 31, 2012

ASSET CLASS #	DESCRIPTION	NBV	% AGE	CURRENT	RECOMMENDED
15200000	NUCLEAR - BUILDINGS AND STRUCTURES	202,581,250	13.84%	55	55
15340000	NUCLEAR - PROCESS SYSTEMS	165,034,350	11.27%	55	55
15600000	NUCLEAR - INSTRUMENTATION AND CONTROL - PA&BG	163,390,095	11.16%	15	15
15701000	NUCLEAR - SERVICE WATER AND FIRE PROTECTION SYSTEM	122,983,880	8.40%	25	25
15720000	NUCLEAR - COMMON SERVICE SYSTEMS	94,104,574	6.43%	35	35
15121000	NUCLEAR - ELECTRONIC SITE SECURITY SYSTEM	77,170,667	5.27%	15	15
15120000	NUCLEAR - YARD FACILITIES	62,632,092	4.28%	50	50
15450000	NUCLEAR - CONDENSER TUBING	59,936,357	4.09%	30	30
15561000	NUCLEAR - AC STANDBY POWER - PB&DG	45,936,441	3.14%	55	55
15361000	NUCLEAR - IRRADIATED FUEL BAYS - PICKERING B	36,512,986	2.49%	65	65
15550000	NUCLEAR - REACTOR BUILDING CABLING	31,313,114	2.14%	40	40
16310000	ADMINISTRATION AND SERVICE BUILDINGS - NUCLEAR TRAINING SIMULATORS	29,502,112	2.02%	45	45
15991000	NUCLEAR - MAJOR / STRATEGIC SPARES	23,310,388	1.59%	100	100
15341100	NUCLEAR - MODERATOR HEAT EXCHANGERS-PICKERING	21,664,508	1.48%	25	25
16560100	ADMINISTRATION AND SERVICE BUILDINGS - INTANGIBLES ADMINISTRATION SYSTEM SOFTWARE	20,482,148	1.40%	5	5
15510000	NUCLEAR - STATION SERVICE MAIN TRANSFORMERS AND AC POWER DISTRIBUTION SYSTEMS-PA&BG	18,723,596	1.28%	40	40
15460000	NUCLEAR - AUXILIARY SYSTEMS - PB&DG	17,433,082	1.19%	40	40
15500000	NUCLEAR - MAIN POWER OUTPUT SYSTEM	17,311,287	1.18%	35	35
15421000	NUCLEAR - GENERATOR ROTORS, STATORS AND AUXILIARY SYSTEMS - PB&DG	14,463,334	0.99%	55	55
15560000	NUCLEAR - AC STANDBY POWER - PA&BG	12,946,426	0.88%	40	40
15710000	NUCLEAR - WATER TREATMENT PLANT	11,755,949	0.80%	20	20
15352100	NUCLEAR - SHUTDOWN COOLING SYSTEM HEAT EXCHANGERS-DARLINGTON	7,180,243	0.49%	30	30
16540000	ADMINSTRATION AND SERVICE BUILDINGS - ADMINISTRATIVE TELECOM EQUIPMENT	6,817,736	0.47%	7	7
15330000	NUCLEAR - REACTIVITY CONTROL UNITS	6,428,607	0.44%	40	40
15461000	NUCLEAR - AUXILIARY SYSTEMS - PB&BG	5,888,839	0.40%	55	55
15711000	NUCLEAR - CIRCULATING WATER - PA&BG	5,645,173	0.39%	55	55
16210000	ADMINSTRATION AND SERVICE BUILDINGS - PERMANENT BUILDINGS, ROADS AND SITE IMPROVEMENTS	5,189,964	0.35%	50	50
15501000	NUCLEAR - REVENUE METERING - MAIN POWER OUTPUT, INSTRUMENTION AND CONTROL-PICK/DARL	4,420,168	0.30%	30	30
15990000	NUCLEAR - ALTERNATE SPARES	3,870,028	0.26%	100	100
15300000	NUCLEAR - REACTOR VESSELS	3,255,283	0.22%	40	40
16211000	ADMINISTRATION AND SERVICE BUILDINGS - BUILDINGS - LEASED	3,053,583	0.21%	10	10
15700000	NUCLEAR - CIRCULATING WATER	2,967,609	0.20%	40	40
16630000	ADMINISTRATION AND SERVICE BUILDINGS - BUILDING SYSTEMS AND EQUIPMENT	2,378,027	0.16%	20	20
15370000	NUCLEAR - TRITIUM REMOVAL FACILITY	2,367,846	0.16%	30	30
15411100	NUCLEAR - TURBINES, AUXILIARY EQUIPMENT, STEAM REHEATER TUBE - PB&DG	1,920,354	0.13%	55	55
15531000	NUCLEAR - BUILDING ELECTRICAL SERVICE SUPPLIES - PB&DG	1,586,505	0.11%	55	55
15352000	NUCLEAR - SHUTDOWN COOLING SYSTEM HEAT EXCHANGERS-PICKERING	1,259,362	0.09%	25	25
16550000	ADMINISTRATION AND SERVICE BUILDINGS - LAN CABLE	1,147,295	0.08%	10	10
18500000	COMMUNICATIONS - RADIO EQUIPMENT	1,030,056	0.07%	15	15
16230000	ADMINISTRATION AND SERVICE BUILDINGS - BUILDINGS- FRAME AND METAL CLAD	1,005,387	0.07%	25	25

ONTARIO POWER GENERATION

SCHEDULE 1B. SUMMARY OF CURRENT AVERAGE SERVICE LIFE ESTIMATES AND GANNETT FLEMING RECOMMENDED AVERAGE SERVICE LIFE ESTIMATES
PRESCRIBED NUCLEAR ASSETS AS AT DECEMBER 31, 2012

ASSET CLASS #	DESCRIPTION	NBV	% AGE	CURRENT	RECOMMENDED
15511000	NUCLEAR - STATION SERVICE MAIN TRANSFORMERS AND AC POWER DISTRIBUTION SYSTEMS - PB&DG	896,419	0.06%	55	55
15541000	NUCLEAR - ELECTRICAL AUXILIARY SYSTEM-PB&DG	791,287	0.05%	55	55
15400000	NUCLEAR - TURBINES, AUXILIARY EQUIPMENT, STEAM REHEATER TUBE -PA&BG	693,921	0.05%	40	40
16311000	ADMINISTRATION AND SERVICE BUILDINGS - NUCLEAR SIMULATORS - DESIGN UPGRADES	456,887	0.03%	10	10
15360000	NUCLEAR - IRRADIATED FUEL BAYS - PICKERING A	400,039	0.03%	40	40
15311000	NUCLEAR - FUEL CHANNEL ASSEMBLIES	154,089	0.01%	25	25
15430000	NUCLEAR - EXCITERS	75,910	0.01%	30	30
18633000	COMMUNICATIONS - OPTICAL WIRE - REVENUE METERING	38,917	0.00%	30	30
18460000	COMMUNICATIONS - DATA ACQ. EQUIP., MAN MACHINE INTERFACE EQUIPMENT	24,631	0.00%	15	15
18630000	COMMUNICATIONS - OPTICAL WIRE	8,636	0.00%	25	25
	MINOR FIXED ASSETS - SERVICE EQUIPMENT	134,697,036	9.20%		
	MINOR FIXED ASSETS - OTHER	8,923,873	0.61%		
NEW	NUCLEAR - ROOFING		0.00%	N/A	25
NEW	NUCLEAR - LARGE CIRCULATING WATER MOTORS - OVER 200 HP		0.00%	N/A	30
	TOTAL	**1,463,762,346**	**100.00%**		
	ASSET RETIREMENT COSTS (ARC)	1,510,363,609			
	GRAND TOTAL	**2,974,125,954**			

APPENDIX 1

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

Account 10318000 – Hydroelectric Gates, Stoplogs and Operating Mechanisms

Current Average Service Life Estimate – 50 years

Recommended Average Service Life Estimate – 55 years

Average of Peer Average Service Lives – 72 years (Range from 50 to 100 years)

Discussion:

This account includes the investment in a number of the operating mechanisms related to the hydroelectric dams, including the head gates and stoplogs. Since the 1990's, OPG has been engaged in a significant gate replacement program. The average replacement age of the original gates has been 40 to 60 years. OPG's Dam Safety Program mandates rigorous annual functional testing, inspection and gate maintenance. Experience gained through these monitoring and assessment programs has shown that after 40-60 years of service life, the gates typically require an extensive rebuild. Replacement parts or components may no longer be commercially available requiring extensive and costly re-engineering to restore original functionality. Replacing with a current gate design takes full advantage of improvements in manufacturing processes, operating mechanism design, material properties, electronic controls, etc. that have occurred over the past 50 years.

Integration of wind and other intermittent renewable sources of generation has increased over time and is expected to continue into the future. As a result, increased cycling of hydro generating units has been experienced, along with a similar increase in gate operation cycles.

In making the recommendation for an increase to the average service life estimate, Gannett Fleming has specifically noted that the life estimates of the peer group have been increasing in recent depreciation studies. A review of peer companies has indicated average service life estimates for the peer group of companies now range from 50 years to as long as 100 years. However, it is noted that the peer companies at the longer end of this range include this investment in their overall dam structures accounts. With the removal of the longer life peer indications from the peer analysis the comparable life estimates of the peer group range from 50 to 80 years with an overall average of 55 years.

The recommended 55-year average service life estimate has been developed giving consideration to all of the above influences. It is expected that improvements in gate design and reliability will be partially offset by moderately increasing frequency of operation, thus the currently assigned life of 50 years can be increased to 55 years, which is consistent with the indications from the adjusted peer analysis.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

NEW ACCOUNT – Hydroelectric Fencing

Current Average Service Life Estimate – 100 years

Recommended Average Service Life Estimate – 25 years

Average of Peer Average Service Lives – 25 to 30 years

Discussion:

This account would include the OPG investment related to site parameter fencing at the hydroelectric facilities. During the operational tours conducted by Gannett Fleming it was specifically noted that OPG had recently undergone a significant program to upgrade its site parameter fencing. OPG intends to continue its focus on public safely through the planned continuation of this program. As such, it is appropriate to set up a separate account for fencing.

A review of the peer companies has indicated average service life estimates ranging from 25 to 30 years with most peer utilities using 25 years. Therefore, based on a peer analysis, an average service life of 25 years is reasonable. Discussions with OPG operational staff have also confirmed that the use of a 25-year average service life for this new account is reasonable.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

NEW ACCOUNT – Hydroelectric Roofing

Current Average Service Life Estimate – 75 to 100 years

Recommended Average Service Life Estimate – 30 years

Average of Peer Average Service Lives – 30 years

Discussion:

This proposed new account relates to the OPG investment in roofing which has shown to have a materially shorter life than the associated buildings. Historically, several of OPG hydroelectric plant roofing systems have reached between 25 to 50 year service life milestones before complete replacement. However, the service life is dependent on the type of roofing material utilized and exposure conditions. The original multi-layer tar and felt roofing systems (with gravel protection) have averaged over 40 years, while the newer roofing systems (EPDM, PVC and TPO) have averaged about 25 to 30 years. The past issues (e.g., premature joint failures, cracking, poor wear resistance, etc.) with the newer systems have been partially resolved through modern material formulations and installation improvements.

A review of the peer companies that have componentized roofing into a separate category has indicated average service life estimates of 30 years. It is also the view of the OPG operational staff that the roofing materials and installations systems currently in place systems will achieve an average service life of 30 years. Therefore, based on the peer analysis, discussions with OPG operational staff, and Gannett Fleming's experience the use of a 30-year average service life for this new account is proposed.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

NEW ACCOUNT – Nuclear Large Circulating Water Motors

Current Average Service Life Estimate – 40 to 55 years

Recommended Average Service Life Estimate – 30 years

Average of Peer Average Service Lives –N/A

Discussion:

This proposed new account relates to the OPG investment in large electric motors of more than 200 horsepower with operating voltages between 2kV and 15kV being used for critical operations and safety systems. A review of operational benchmark information from the Electric Power Research Institute ("EPRI") and the United States Nuclear Regulatory Commission ("US NRC") indicates that the expected life of a large high voltage motor ranges from 24 years to 40 years. Due to the high voltages and large rotating masses involved, the electrical and mechanical wear and tear occurs in these motors at a higher rate than experienced by smaller motors. OPG operational experience has shown that large motors, such as the Darlington Heat Transport Pump Motors, are approaching failure at the rates predicted by the US NRC-sponsored research and EPRI. A complete teardown and rebuild is required to extend the life of these motors. In the case of the Darlington motors, spare motors are being purchased to facilitate the rebuild of the 16 in-service motors.

Given the different average service life expectations associated with these motors, Gannett Fleming recommends the creation of a new account for the investment in large circulating water motors with an average service life of 30 years. The recommended life of 30 years is consistent with the mid-point of the expected lives in the US NRC-sponsored and EPRI reports and OPG's operational experience.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

NEW ACCOUNT – Nuclear Roofing

Current Average Service Life Estimate – 55 years

Recommended Average Service Life Estimate – 25 years

Average of Peer Average Service Lives – N/A

Discussion:

This proposed new account relates to the OPG investment in roofing of Nuclear Buildings and Structures which has shown to have a materially shorter life than the associated buildings. A 2012 Station Roof Replacement Project was initiated as the station roofs were reaching the end of their 25-year design life. OPG's internal assessments have indicated that station roofing requires repair or replacement, with the condition of the roofing deteriorating due to its age. A number of work orders associated with the condition of the roofs been initiated.

Based on the design life and the operating experience of OPG, Gannett Fleming recommends that OPG should create a new account for nuclear roofing, with a 25-year average service life.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

Reclassification of Nuclear Turbine Generator Controls from Account 15411100 – Nuclear Turbines and Auxiliaries to Account 15600000 – Nuclear Instrumentation and Control

Current Average Service Life Estimate – 55 years as part of Account 15411100

Recommended Average Service Life Estimate – 15 years as part of Account 15600000

Average of Peer Average Service Lives – 15 to 25 years

Discussion:

Gannett Fleming recommends a change in the coding of the nuclear turbine generator controls from Account 15411100 – Nuclear Turbines and Auxiliaries to Account 15600000 – Nuclear Instrumentation and Control. It is the view of Gannett Fleming that the emergence of digital technology for turbine generator control equipment results in the 55-year life estimate associated with Account 15411100 being no longer appropriate for these specific assets. It is also noted that, in general, the turbine generator control systems are more similar in technology and life characteristics to the assets recorded in Account 15600000. As such, Gannett Fleming recommends that these assets be reclassified to Account 15600000.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Niagara Tunnel Lining

NEW ACCOUNT – Hydroelectric – Niagara Falls- New Tunnel Lining

Current Average Service Life Estimate – N/A

Recommended Average Service Life Estimate – 90 years

Average of Peer Average Service Lives – N/A

Discussion:

The investment in this account relates to the lining material of the Niagara Tunnel that was placed into service in the first quarter of 2013. The 2011 Depreciation Study conducted by Gannett Fleming and internal OPG depreciation reviews have recommended a life estimate of 75 years for the linings associated with the two original tunnels at Niagara Falls. This estimated service life for existing OPG tunnel linings of 75 years is consistent with industry practice.

The Niagara Tunnel Project ("NTP") was an extremely large, complex, and challenging construction project with an estimated total capital cost of approximately $1.5 Billion. Most of the investment was placed in service in March 2013. Based on its review of the NTP, it is the view of Gannett Fleming that the tunnel excavation investment would have a similar life of 100 years as expected for the existing two Niagara tunnels and other hydroelectric excavation. However, Gannett Fleming's review also specifically noted that the NTP tunnel lining material installation procedures, were specifically designed and the tunnel was specifically constructed for a service life of 90 years. In fact, the 90-year design life was a specific requirement of the NTP to be considered by contractors working on this project. As such, the technical specifications and material used in both the new tunnel construction and tunnel lining have a stated mandatory requirement for a service life of 90 years for the lining system and structures of the Niagara Tunnel Facility.

In making the above recommendation associated with the new tunnel lining, Gannett Fleming's review included:

- A tour of the new tunnel construction activity in 2011 as part of the Sir Adam Beck facility tour conducted as part of the 2011 Depreciation Study;
- Technical design specifications for the project;
- Owner's mandatory requirements for the tunnel facility contained in OPG's Design and Build Contract with Strabag AG;
- A number of discussions with NTP staff regarding the project (and specifically the tunnel lining);
- DRC work and documentation related to the lining investment for the new tunnel; and

- OPG's evidence with respect to the NPT filed with the OEB as part of the EB-2013-0321 proceeding (Ex. D1-2-1).
.

Gannett Fleming considers the above reviews as sufficient evidence to establish the average service life for the new Niagara Tunnel lining at 90 years, as recommended by the 2012 DRC. As the two existing tunnels are recommended to continue to be depreciated over 75 years, the investment associated with the 2013 tunnel lining should be segregated into a separate account.

APPENDIX 2

APPENDIX 2

ONTARIO POWER GENERATION

NEWLY REGULATED HYDROELECTRIC FACILITIES

<u>Ottawa-St. Lawrence Plant Group</u>:

Arnprior Station
Barrett Chute Station
Calabogie Station
Mountain Chute Station
Stewartville Station
Chats Falls Station
Chenaux Station
Des Joachims Station
Otto Holden Station

<u>Northeast Plant Group</u>:

Abitibi Canyon Station
Otter Rapids Station
Lower Notch Station
Matabitchuan Station
Indian Chute Station

<u>Central Hydro Plant Group</u>:

Auburn Station
Big Chute Station
Big Eddy Station
Bingham Chute Station
Coniston Station
Crystal Falls Station
Elliot Chute Station
Eugenia Falls Station
Frankford Station
Hagues Reach Station
Hanna Chute Station
High Falls Station
Lakefield Station
McVittie Station
Merrickville Station
Meyersburg Station
Nipissing Station
Ragged Rapids Station
Ranney Falls Station
Seymour Station
Sidney Station
Sills Island Station
South Falls Station
Stinson Station
Trethewey Falls Station

<u>Northwest Plant Group</u>:

Aquasabon Station
Alexander Station
Cameron Falls Station
Caribou Falls Station
Kakabeka Falls Station
Manitou Falls Station
Pine Portage Station
Silver Falls Station
Whitedog Falls Station

Section:	Appendix 5.6	**Page No.:**	MIPUG/MH I-19a
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation		
Issue:	Overview of Depreciation Method changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please refile MIPUG/MH I-19 (a) pages 7 & 8 assuming that ASL is retained and net salvage is removed for rate-setting purposes.

b) Please discuss the financial reporting implications of recording depreciation for rate-setting purposes based on (a) for 2015/16.

RATIONALE FOR QUESTION:

To assess the impact of retaining ASL for rate-setting purposes.

RESPONSE:

a) The following schedule identifies the incremental impact on annual depreciation expense of the following items assuming that CGAAP ASL is retained and net salvage is removed for rate-setting purposes. Please note that the depreciation expense figures shown in this response are not IFRS compliant:

- Net asset additions (additions net of retirements);
- 2010 Depreciation Study – incremental changes resulting from the 2010 changes to componentization and to average service lives applied to net additions;
- 2014 Depreciation Study changes to average service lives;
- Implementation of IFRS changes other than the change to an IFRS compliant depreciation method (ELG), including removal of the provision for net salvage from depreciation rates, removal of IFRS ineligible costs from capitalized overhead and capitalization of meter exchange program costs.

MANITOBA HYDRO - CONSOLIDATED ELECTRIC OPERATIONS
DEPRECIATION AND AMORTIZATION EXPENSE

	2014/15 Forecast *	Year over Year Change (Forecast): Net Additions	2010 Depn Study: Change in Asset Life	2014 Depreciation Study: Change in Asset Life	2014 Depreciation Study: Removal of Net Salvage	IFRS Remove Indirect Overhead	Capitalize Meter Exchange Program	2015/16 Forecast *
Generation								
Hydraulic Generating Stations	112,990	7,237	415	(3,749)	(13,690)	-	-	103,203
Thermal Generating Stations	15,770	85	9	5	(1,731)	-	-	14,138
Demand Side Management	31,576	3,381	-	-	-	-	-	34,957
Diesel Generating Stations	2,342	586	(500)	13	(121)	-	-	2,320
Amortization of Contributions	(1,049)	(399)	302	-	-	-	-	(1,146)
	$ 161,629	$ 10,890	$ 225	$ (3,730)	$ (15,542)	$ -	$ -	$ 153,472
Transmission								
Transmission	16,329	614	(13)	(2)	(4,244)	-	-	12,684
Amortization of Contributions	(1,391)	(228)	1	-	-	-	-	(1,618)
	$ 14,938	$ 386	$ (12)	$ (2)	$ (4,244)	$ -	$ -	$ 11,065
Stations								
Substations	88,555	12,264	(767)	(3,322)	(18,922)	-	-	77,807
Transformers	1,627	(2,085)	49	2,426	(502)	-	-	1,514
Amortization of Contributions	(1,170)	185	-	-	-	-	-	(985)
	$ 89,012	$ 10,364	$ (718)	$ (896)	$ (19,425)	$ -	$ -	$ 78,337
Distribution								
Subtransmission Lines	7,376	1,300	(473)	(61)	(2,753)	-	-	5,390
Distribution Lines	60,514	6,418	(2,737)	98	(16,693)	-	-	47,601
Meters & Metering Transformers	2,848	(23)	(21)	112	6	-	31	2,952
Amortization of Contributions	(5,678)	(1,663)	925	43	(13)	-	-	(6,386)
	$ 65,061	$ 6,032	$ (2,306)	$ 192	$ (19,452)	$ -	$ 31	$ 49,557
Other								
Communications	17,167	553	251	(314)	(1,186)	-	-	16,472
Motor Vehicles	10,162	759	(75)	(76)	(31)	-	-	10,738
Structures & Improvements	7,928	543	130	(87)	(402)	-	-	8,112
General Equipment	16,631	(739)	(495)	1,387	1	-	-	16,784
Computer Development	17,687	785	(62)	(163)	1	-	-	18,248
Affordable Energy Fund	5,270	(980)	-	-	-	-	-	4,290
Miscellaneous	1,701	1,029	(11)	124	(458)	-	-	2,385
Corporate Allocation	(1,974)	(6)	(6)	(55)	458	-	-	(1,583)
Target Adjustment	(621)	(2,498)	-	(8)	515	(419)	-	(3,030)
	$ 73,951	$ (554)	$ (268)	$ 808	$ (1,103)	$ (419)	$ -	$ 72,416
Total Dep'n and Amort Expense	$ 404,590	$ 27,118	$ (3,080)	$ (3,628)	$ (59,765)	$ (419)	$ 31	$ 364,847

* 2014/15 and 2015/16 Forecast figures have been restated from those shown in the response to PUB-MH II-33a to reflect the reallocation of Wuskwatim costs into the respective asset reporting categories.

MANITOBA HYDRO - CONSOLIDATED ELECTRIC OPERATIONS
DEPRECIATION AND AMORTIZATION EXPENSE

	2015/16 Forecast *	Year over Year Change (Forecast)						2016/17 Forecast *
		Net Additions	2010 Depn Study	2014 Depreciation Study		IFRS Remove	Capitalize Meter	
			Change in Asset Life	Change in Asset Life	Removal of Net Salvage	Indirect Overhead	Exchange Program	
Generation								
Hydraulic Generating Stations	103,203	4,532	145	120	(1,769)	-	-	106,231
Thermal Generating Stations	14,138	69	23	6	(41)	-	-	14,195
Demand Side Management	34,957	2,544	-	-	-	-	-	37,501
Diesel Generating Stations	2,320	(128)	(73)	(245)	-	-	-	1,874
Amortization of Contributions	(1,146)	-	-	-	-	-	-	(1,146)
	$ 153,472	$ 7,017	$ 96	$ (120)	$ (1,810)	$ -	$ -	$ 158,655
Transmission								
Transmission	12,684	1,385	(56)	(48)	(369)	-	-	13,596
Amortization of Contributions	(1,618)	(3)	(2)	-	-	-	-	(1,623)
	$ 11,065	$ 1,382	$ (58)	$ (48)	$ (369)	$ -	$ -	$ 11,972
Stations								
Substations	77,807	5,882	(429)	(720)	(849)	-	-	81,690
Transformers	1,514	(30)	44	337	(97)	-	-	1,768
Amortization of Contributions	(985)	-	-	-	-	-	-	(985)
	$ 78,337	$ 5,852	$ (386)	$ (383)	$ (946)	$ -	$ -	$ 82,474
Distribution								
Subtransmission Lines	5,390	797	(289)	(29)	(106)	-	-	5,763
Distribution Lines	47,601	7,501	(2,789)	(487)	(907)	-	-	50,919
Meters & Metering Transformers	2,952	(35)	68	(53)	16	-	114	3,062
Amortization of Contributions	(6,386)	(1,520)	875	53	(7)	-	-	(6,985)
	$ 49,557	$ 6,743	$ (2,135)	$ (515)	$ (1,004)	$ -	$ 114	$ 52,760
Other								
Communications	16,472	697	268	(740)	139	-	-	16,835
Motor Vehicles	10,738	417	(41)	34	(51)	-	-	11,097
Structures & Improvements	8,112	700	144	(103)	(44)	-	-	8,809
General Equipment	16,784	(650)	(355)	1,026	-	-	-	16,804
Computer Development	18,248	2,814	82	(604)	-	-	-	20,540
Conawapa	-	7,711	-	-	-	-	-	7,711
Affordable Energy Fund	4,290	(2,781)	-	-	-	-	-	1,509
Miscellaneous	2,385	642	21	(47)	2	-	-	3,003
Corporate Allocation	(1,583)	0	(28)	27	(2)	-	-	(1,586)
Target Adjustment	(3,030)	(1,750)	-	(58)	615	(2,100)	-	(6,324)
	$ 72,416	$ 7,800	$ 90	$ (464)	$ 658	$ (2,100)	$ -	$ 78,399
Total Dep'n and Amort Expense	$ 364,847	$ 28,794	$ (2,393)	$ (1,530)	$ (3,471)	$ (2,100)	$ 114	$ 384,260

* 2015/16 and 2016/17 Forecast figures have been restated from those shown in the response to PUB-MH II-33a to reflect the reallocation of Wuskwatim costs into the respective asset reporting categories.

b) Please see the response to PUB/MH-II-21c for a discussion on the implications of recording depreciation for rate-setting purposes based on the CGAAP ASL method.

Section:	Tab 3	Page No.:	Coalition MH I-19 (d) / PUB/MH I-6 a-c
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Financial Targets		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's financial targets are subject to assumptions that may not be met during periods of cash shortfalls.

QUESTION:

a) Please describe the mitigating actions to meet Manitoba Hydro's financial targets during the 2003/04 drought.
b) Please describe the mitigating actions that MH can take to address an interest coverage ratio below 1.0 and indicate at what ratio the Corporation could operate and still meet its interest obligations.
c) Discuss the implications of a drought on meeting the interest coverage ratio, in particular if one were to coincide with the years MH's interest coverage ratio falls below 1.0.

RATIONALE FOR QUESTION:

To assess the mitigation measures Manitoba Hydro can take during periods of cash shortfall.

RESPONSE:

<u>Response to parts a-c)</u>

Manitoba Hydro did not meet its financial targets in 2003/04 as a result of the drought. During this time, Manitoba Hydro undertook a number of drought management activities such as decreasing off-peak exports and operating coal-fired generation, in order to mitigate the negative financial impact of the drought. Manitoba Hydro also undertook other activities such conserving cash by reducing corporate expenditures, securing additional bridge financing and obtaining rate increases (see Appendix 11.9 for the details of rate increase requested and approved, as well as Orders 101/04 and 143/04 that provided rate increases arising from the 2003/04 drought).

Moving forward, given the substantial capital expenditure forecast, Manitoba Hydro's ability to generate sufficient cash flows to meet its financial obligations is critical. Liquidity and access to capital will be essential for business continuity. Manitoba Hydro is of the view that the IFF14 base case, with the 3.95% annual rate increases, is manageable and that Manitoba Hydro's self-supporting status will be maintained. To span across short term cash shortfalls, Manitoba Hydro can undertake a series of actions similar to those undertaken during the 2003/04 drought (such as cash conservation, bridge financing and higher rate increases). Please see the response to PUB/MH-II-72a-d for a discussion of the debt management activities that Manitoba Hydro is undertaking to proactively mitigate the impact associated with future cash shortfalls.

Substantial cash shortfalls, for example in the case of severe prolonged drought would place significant downward pressure on the Corporation's financial ratios, including the interest coverage ratio.

Directionally, the lower the interest coverage ratio, the greater the operational liquidity risk that the Corporation will have insufficient cash flow from operations to meet its sustaining expenditures and financial obligations.

Manitoba Hydro's interest coverage ratio provides an indication of the ability of the Corporation to meet interest payment obligations with the net income generated by the Corporation. The ratio is calculated as net income plus gross interest expense, with this sum divided by gross interest expense. Gross interest (which is in both the ratio's numerator and denominator) is before any adjustment for capitalized interest. Net income (which is only in the ratio's numerator) excludes the capitalized interest but includes depreciation expense (which is a partial proxy for the cash flow required to replace depreciating assets and fund sustaining capital expenditures).

Annual interest coverage at or greater than 1.20 provides a margin of earnings in excess of that which is required to cover interest payments to bondholders. As Manitoba Hydro's net income within the interest coverage ratio includes non-cash items such depreciation expense, it is estimated that the Corporation could theoretically meet its interest obligations at a ratio of approximately 0.80. If the interest coverage ratio is below 1.00, the risk of cash shortfalls from operations becomes serious, especially if there are other adverse circumstances such as a drought. Should these adverse circumstances arise during these periods of vulnerability, one of the potential implications would be the need for higher rate increases.

Manitoba Hydro's interest coverage ratio is forecast to be well below target for several years of the forecast. In eight years of the forecast, Manitoba Hydro's interest coverage ratio is below 1.00. In these circumstances, in order to maintain the same level of sustaining expenditures and customer service, there is elevated risk that Manitoba Hydro would need to secure additional debt – thereby increasing finance expense and ultimately raising customer rates.

Manitoba Hydro will continue to take appropriate actions to ensure it remains a self-supporting corporation. This includes seeking the annual rate increases necessary to maintain financial ratios and rate stability for customers. Based on the financial outlook in MH14, the 3.95% annual proposed and indicative rate increases are the minimum required.

Section:	Tab 3: Section 3.1	Page No.:	PUB/MH I-6 (b) & (c)
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Key Financial Risks		
Issue:	Credit Rating of Province of Manitoba & Manitoba Hydro		

PREAMBLE TO IR (IF ANY):

In PUB/MH I-6, MH states that:

> *Considering the unprecedented levels of debt financing during the next few years, the projected losses of approximately $1 billion over a ten year period in the IFF14 base case (which includes the assumption of 3.95% annual rate increases), would place downward pressure on the Corporation's self-supporting status. While the capital markets are deep, this level of debt financing may also apply pressure on the province's credit spreads.*

QUESTION:

a) If MH's budgeted deficit of approximately $1 billion has the potential to apply pressure on the province's credit spreads, could that mean higher borrowing costs for the Province?

b) Please explain what pressure on the Province's credit spreads might mean related to the Province's and Manitoba Hydro's cost of borrowing.

c) Please indicate whether MH has provided any analysis of the potential impact of MH forecasting $1 billion in losses on the Provincial treasury.

d) Please indicate the potential increase in borrowing costs over the forecast period if the Credit Rating of the Province was downgraded one level. Provide the estimated incremental increase in interest rates and borrowing costs.

RATIONALE FOR QUESTION:

To understand the implications of MH's forecasts on borrowing costs and the Province.

RESPONSE:

Response to part a) and b)

Manitoba Hydro's budgeted deficits of approximately $1 billion, if realized and unmitigated, have the potential to lead to higher borrowing costs for Manitoba Hydro and the Province.

Substantial cash shortfalls, for example in the case of severe drought or if the projected losses of approximately $1 billion over a ten year period in the IFF14 base case become realized (which includes the assumption of 3.95% annual rate increases), would place downward pressure on the Corporation's self-supporting status. While the capital markets are deep, this level of debt financing may also apply pressure on the province's credit spreads. As these cash shortfalls would likely require additional debt financing, more supply of Manitoba bonds would be placed into the financial markets which may require pricing incentives for investors in the form of wider credit spreads and higher bond yields.

Manitoba Hydro has undertaken a number of debt management activities in order to mitigate the potential pressure on Manitoba credit spreads, such as:

- Reducing the interest rate risk exposure on the existing debt portfolio by decreasing the proportion of floating rate debt within the portfolio.
- Reducing the interest rate risk exposure on the existing debt portfolio by extending the weighted average term to maturity by issuing longer dated debt, including the issuance of ultra long debt with terms to maturity beyond 30 years.
- Managing the refinancing risk within the existing debt portfolio by having a relatively smooth debt maturity schedule.
- Reducing Manitoba Hydro's liquidity risk and enhancing financing flexibility by maintaining positive cash balances and/or access to liquidity.
- Establishing benchmark sized debt issues so that investors may reduce their market risk by having liquid bonds that can be readily traded in the financial markets.
- Diversifying the investor base by varying the terms to maturity for debt issuance so that investors with different term preferences may participate in Manitoba issues.
- Diversifying the investor base beyond the domestic Canadian capital markets by issuing Manitoba bonds into international markets.

Response to part c)

Manitoba Hydro cannot disclose cabinet confidences nor does it disclose advice, opinions, recommendations, analyses or policy options developed by or for a minister. In Order 33/15, the PUB accepted Manitoba Hydro's submission that cabinet confidences should not be disclosed.

Response to part d)

The incremental increase in interest rates and borrowing costs associated with a one level downgrade cannot be conclusively determined. As described in response to PUB/MH-I-6, should the credit rating for the Province of Manitoba be downgraded, the financial impact upon Manitoba Hydro's access to financing and borrowing costs would depend upon a number of factors. The financial markets are a complex system with many moving parts and the last downgrade for the Province of Manitoba occurred nearly 30 years ago in 1986. On August 18, 2014 Moody's placed the Province of Manitoba's Aa1 long term debt rating on a negative outlook.[1] Manitoba Hydro observes that since mid-July 2014, the Province of Manitoba's provincial credit spreads relative to the Ontario provincial benchmark have weakened by 7 to 10 basis points for 10 and 30 year bonds respectively (although it remains unclear to what degree the negative outlook impacted the relative spread performance as investors have recently shown a preference for big liquid issues of Ontario and Quebec in these markets as opposed the less frequent issuers such as Manitoba).

[1] Moody's P-1 short term rating on the Manitoba Hydro-Electric Board's commercial paper program was not affected. Credit ratings and outlooks from S&P and DBRS remained unchanged. Moody's also placed the Province of Ontario's Aa2 long term debt rating on a negative outlook on July 2, 2014.

Section:	Tab 3	Page No.:	Coalition MH I-19 (g)
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Financial Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain why sustaining capital expenditures in 2026 to 2032 are materially higher than what was forecast in previous forecasts.

b) Please discuss the relationship between Plant in Service and sustaining capital expenditures. In particular increase why there are higher levels of sustaining capital spending given the removal of Conawapa from the IFF14 forecast.

RATIONALE FOR QUESTION:

To explore the relationship between sustaining capital spending and major new generation & transmission.

RESPONSE:

a) Sustaining capital expenditures in the period 2026 to 2032 were increased in CEF14 primarily to reflect the findings of the Asset Condition Assessment report due to aging infrastructure. With the significant capital investment in Major New Generation and Transmission in the 10-year period of the forecast to 2024, as well as more consequential capital related issues due to customer growth, accelerated replacement of aging assets will not occur until the latter forecast years.

b) The provisions for sustaining capital expenditures are generally assumed to be placed in-service in October and March of each year. As a result, sustaining capital plant in-service generally tracks closely to the associated capital expenditures.

The schedule in the response to COALITION/MH-I-32c (i-iv) provides the continuity of capital expenditures, construction in progress, and in-service additions from construction in progress to plant in service. However, once Keeyask is in-service by 2022, the additions to plant in service are primarily related to sustaining capital expenditures from 2023 through to the end of the forecast period in 2034.

As noted in a) above, sustaining capital expenditures are for the replacement and refurbishment of existing infrastructure, load growth, as well as addressing capacity constraints and are unrelated to Conawapa.

Section:	Tab 4, Appendix 4.1	Page No.:	PUB/MH I-20(e)
Topic:	Capital Expenditure Forecast		
Subtopic:	Bipole III Project Costs		
Issue:	Cost Escalations and Scope Change		

PREAMBLE TO IR (IF ANY):

The provided 2010 CPJ calculations of Bipole III budget estimates breakdowns are as follows:

– licensing & properties	$ 188M
– transmission line	1,210M
– Keewatinow converter station	948M
– Keewatinow AC collector system	294M
– Riel converter station	1,467M
Total for Bipole III	$4,107M

QUESTION:

a) Provide a similar line item estimate of MH's 2014 budget estimate of $4.65B.
b) Explain the changes in budget line items going from 2010 to 2014.
c) Identify any specific scope changes any cost implications.

RATIONALE FOR QUESTION:

MH's budget increase for Bipole III from $3.27B to $4.65B needs a detailed explanation.

RESPONSE:

a) The following table outlines the Bipole III 2014 Control Budget in the requested format:

Estimate Item	**2014 Bipole III Control Budget** *(in Millions $)*
Licensing & Properties	$255.8
Transmission Line	$1,422.7
Keewatinohk Converter Station	$1,476.9
AC Collector System	$255.4
Riel Converter Station (*including Riel Expansion*)	$1,179.8
Community Development Initiative (CDI)	$61.9
Total Cost for Bipole III	**$4,652.5**

b) Manitoba Hydro provided the CPJ's which have been approved over the last 4 years in its response to PUB/MH I-20e. Please refer to the response provided in PUB/MH I-20a for the explanations on the increase to the Bipole III budget from the $3,279.8 billion amount included in CEF10-2, CEF11-2, and CEF 12 to the updated cost in CEF14 of $4,652.5.

c) Please refer to PUB/MH-II-13a-d for explanation of the change to the HVDC Converter capacity. There are no other scope changes to note.

Section:		**Page No.:**	PUB/MH I-80(a)
Topic:	CEC Hearings – Lake Winnipeg Regulation (LWR)		
Subtopic:	License Renewal Implications		
Issue:	Reducing operating range to 711 to 714		

PREAMBLE TO IR (IF ANY):

PUB/MH I-80(a) used NFAT Plan 14 (which included Conawapa) to calculate the net income impact of a one foot reduction in operating range.

QUESTION:

a) Provide a revised 20 year IFF14 comparison which excludes Conawapa and includes the enhanced DSM as per 2014 PRP.

b) Provide a revised IFF14 based present value estimate of the lost revenue related to the one foot reduction.

RATIONALE FOR QUESTION:

To explore the financial impact of a change to the LWR licence in the absence of Conawapa.

RESPONSE:

a) As noted in PUB/MH-I-80a, Manitoba Hydro is not seeking any change to the license nor did it suggest alternatives to the license. It is noted that the impacts of LWR operating ranges below include the financial impacts only and does not include any costs to mitigate adverse affects to stakeholders.

Projected financial statements for the one foot decrease in the LWR operating range scenario has been updated based on IFF14 assumptions which exclude Conawapa and include the enhanced DSM.

Under an average of all historic flows, the reduced LWR operating range results in lower dependable energy which requires additional energy resources by around

2033/34 at an in-service cost of approximately $340 million. Projected net extraprovincial revenues (net of water rentals and fuel and power purchases) are approximately $425 million lower compared to the base scenario due to lower long-term firm export sales and lower thermal requirements partially offset by higher opportunity export sales and higher power purchased. Assuming the same 3.95% even annual rate increases as the base scenario, the reduction in net extraprovincial revenues results in higher borrowing requirements and finance expense of approximately $260 million. Overall, retained earnings are $697 million lower compared to the base scenario by 2033/34. In order to achieve the same retained earnings as in MH14 by 2033/34, equal annual rate increases of 4.07% from 2015/16 to 2030/31 (followed by 2% rate increases) would be necessary.

b) The following table provides the present value of net extraprovincial revenue reductions assuming a 6.95% nominal discount rate.

Fiscal Year	Nominal WACC	Discount Factor	Change in Net Extraprovincial Revenue	Discounted Change in Net Extraprovincial Revenue	
			In Millions $		
2015		1.000			
2016	6.95%	1.070			
2017	6.95%	1.144	(22)	(19)	
2018	6.95%	1.223	(15)	(13)	
2019	6.95%	1.308	(12)	(9)	
2020	6.95%	1.399	(14)	(10)	
2021	6.95%	1.497	(21)	(14)	
2022	6.95%	1.601	(21)	(13)	
2023	6.95%	1.712	(25)	(15)	
2024	6.95%	1.831	(27)	(15)	
2025	6.95%	1.958	(16)	(8)	
2026	6.95%	2.094	(18)	(9)	
2027	6.95%	2.240	(34)	(15)	
2028	6.95%	2.395	(27)	(11)	
2029	6.95%	2.562	(31)	(12)	
2030	6.95%	2.740	(30)	(11)	
2031	6.95%	2.930	(37)	(13)	
2032	6.95%	3.134	(35)	(11)	
2033	6.95%	3.352	(4)	(1)	
2034	6.95%	3.585	(35)	(10)	
Total			(426)	**(209)**	**NPV**

ELECTRIC OPERATIONS (PUB_MH_II_75 1 Foot Decrease LWR)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
additional*	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	433	448	472	501	801	931	942	972
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	1 992	2 092	2 215	2 339	2 716	2 931	3 037	3 167
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	600	606	619	631
Finance Expense	495	510	548	583	754	890	1 199	1 331	1 341	1 358
Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752
Water Rentals and Assessments	124	123	111	112	112	114	124	127	131	132
Fuel and Power Purchased	134	130	197	209	213	207	240	272	267	279
Capital and Other Taxes	99	107	121	134	143	144	144	150	150	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	1 962	2 052	2 325	2 475	2 931	3 164	3 255	3 323
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	115	37	47	(104)	(133)	(204)	(232)	(219)	(160)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	13%	12%	10%	9%	9%
Interest Coverage	1.16	1.16	1.04	1.05	0.91	0.89	0.84	0.83	0.84	0.88
Capital Coverage	0.98	1.02	0.90	1.07	0.86	0.78	0.78	0.89	1.03	1.16

ELECTRIC OPERATIONS (PUB_MH_II_75 1 Foot Decrease LWR)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	1 551	1 565	1 580	1 593	1 607	1 624	1 641	1 659	1 677	1 696
additional*	734	832	935	1 043	1 157	1 280	1 409	1 486	1 566	1 649
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	986	920	919	907	901	907	885	874	882	875
Other	16	17	17	18	18	18	19	19	19	20
	3 288	3 334	3 450	3 561	3 683	3 829	3 954	4 037	4 144	4 240
EXPENSES										
Operating and Administrative	643	656	669	682	696	706	719	733	747	763
Finance Expense	1 363	1 362	1 352	1 355	1 343	1 324	1 289	1 224	1 188	1 158
Depreciation and Amortization	767	780	791	804	811	820	831	842	857	882
Water Rentals and Assessments	133	133	133	133	134	134	135	135	138	137
Fuel and Power Purchased	285	285	293	296	303	312	318	325	322	359
Capital and Other Taxes	162	163	164	165	166	167	168	170	174	175
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3 364	3 389	3 412	3 445	3 463	3 473	3 468	3 438	3 434	3 483
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(80)	(56)	35	110	214	346	473	584	693	738
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.31%	53.13%	59.18%	65.47%	72.01%	78.80%	85.86%	89.58%	93.37%	97.24%
Financial Ratios										
Equity	9%	9%	9%	10%	11%	12%	14%	17%	19%	22%
Interest Coverage	0.94	0.96	1.02	1.08	1.16	1.26	1.36	1.47	1.56	1.62
Capital Coverage	1.22	1.27	1.40	1.52	1.62	1.86	1.95	2.11	2.24	2.31

ELECTRIC OPERATIONS (PUB_MH_II_75 1 Foot Decrease LWR)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 296	2 599	2 728	2 167	2 239	2 443
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 586	27 669	28 299	27 727	27 789	27 967
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 906	22 792	22 955	23 450	23 641
Current and Other Liabilities	2 016	2 151	2 119	3 109	2 269	2 726	2 703	2 229	1 985	2 095
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 778	2 815	2 862	2 758	2 624	2 420	2 188	1 969	1 809
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 586	27 669	28 299	27 727	27 789	27 967

ELECTRIC OPERATIONS (PUB_MH_II_75 1 Foot Decrease LWR)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 836	43 291
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 384)	(17 200)	(18 040)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 710	24 666	24 636	25 251
Construction in Progress	322	344	225	254	277	323	365	524	763	255
Current and Other Assets	2 389	2 539	2 791	3 066	3 448	3 745	3 538	4 013	4 466	5 099
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27 916	28 065	28 306	28 550	28 910	29 163	28 939	29 521	30 181	30 916
LIABILITIES AND EQUITY										
Long-Term Debt	23 595	24 398	24 601	24 743	24 876	24 149	24 139	24 143	24 137	23 781
Current and Other Liabilities	2 133	1 497	1 464	1 419	1 395	1 991	1 267	1 222	1 156	1 470
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	1 729	1 672	1 706	1 816	2 029	2 375	2 847	3 430	4 123	4 861
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 916	28 065	28 306	28 550	28 910	29 163	28 939	29 521	30 181	30 916

ELECTRIC OPERATIONS (PUB_MH_II_75 1 Foot Decrease LWR)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	2 023	2 125	2 224	2 336	2 713	2 928	3 034	3 164
Cash Paid to Suppliers and Employees	(803)	(871)	(948)	(980)	(1 005)	(1 016)	(1 074)	(1 107)	(1 131)	(1 167)
Interest Paid	(511)	(514)	(547)	(592)	(785)	(930)	(1 221)	(1 355)	(1 337)	(1 350)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	587	550	584	469	425	449	495	581	664
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 600	1 590	600	760	580
Sinking Fund Withdrawals	110	21	-	7	448	205	294	717	165	28
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 470	933	574	443	286
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(246)	(263)	(358)	(253)	(260)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 516)	(1 831)	(1 303)	(1 144)	(981)	(987)
Net Increase (Decrease) in Cash	(270)	(78)	63	(67)	(34)	64	79	(76)	43	(38)
Cash at Beginning of Year	133	(137)	(214)	(152)	(219)	(253)	(189)	(109)	(185)	(143)
Cash at End of Year	(137)	(214)	(152)	(219)	(253)	(189)	(109)	(185)	(143)	(180)

ELECTRIC OPERATIONS (PUB_MH_II_75 1 Foot Decrease LWR)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 285	3 331	3 447	3 558	3 680	3 825	3 951	4 034	4 141	4 236
Cash Paid to Suppliers and Employees	(1 186)	(1 199)	(1 220)	(1 237)	(1 259)	(1 279)	(1 299)	(1 321)	(1 338)	(1 391)
Interest Paid	(1 360)	(1 361)	(1 369)	(1 386)	(1 389)	(1 385)	(1 367)	(1 279)	(1 258)	(1 243)
Interest Received	20	22	35	49	63	72	84	64	79	94
	759	793	894	983	1 095	1 234	1 369	1 498	1 623	1 697
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	390	780	190	190	180	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	298	105	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	255	405	161	163	155	(22)	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(922)	(1 035)	(956)
Sinking Fund Payment	(272)	(272)	(280)	(294)	(307)	(318)	(325)	(303)	(314)	(325)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 047)	(1 053)	(1 058)	(1 065)	(1 095)	(1 091)	(1 138)	(1 251)	(1 376)	(1 308)
Net Increase (Decrease) in Cash	(32)	144	(3)	81	154	121	189	189	200	343
Cash at Beginning of Year	(180)	(212)	(68)	(72)	10	164	285	474	663	863
Cash at End of Year	(212)	(68)	(72)	10	164	285	474	663	863	1 206

Section:	Appendix 7.1	Page No.:	MIPUG I-25
Topic:	Electric Load Forecast		
Subtopic:	Historical Accuracy		
Issue:	Initial year forecasts		

PREAMBLE TO IR (IF ANY):

MIPUG I-25 indicates that MH's first load forecasts for the three GSL subclasses are typically higher than actuals for 2013/14:

	Forecast (GWh)	Actual (GWh)	
GSL <30	1746	1687	(59)
GSL 30-100	1438	1283	(145)
GSL >100	4610	4222	(388)

QUESTION:

a) Explain why MH's 2013/14 load forecast for the initial forecast year was significantly higher than actual.

b) Explain why GSL >100 actual loads have not increased over the last four years why the 2013/14 actual is 1400 GWh lower than forecast in 2010.

c) Explain why GSL 30-100 loads have grown by 445 GWh over the last four years and are now forecast to increase by 523 GWh in the next four years.

d) Indicate what portions of the new pipeline load are GSL 30-100 & GSL >100.

RATIONALE FOR QUESTION:

To gain an appreciation of MH's near future industrial load growth prospects.

RESPONSE:

a) The table shown in the preamble compares different years as it presents the 2014 forecast for 2014/15 compared to 2013/14 actuals. The following table presents the

2013 forecast for 2013/14 compared to the actual energy use for 2013/14.

	2013 Forecast for 2013/14 (GWh)	2013/14 Actual (GWh)	Difference
GSL <30	1 679	1 687	9
GSL 30-100	1 324	1 283	(41)
GSL >100	4 651	4 222	(429)

The observed difference between 2013/14 actuals compared to forecast load for 2013/14 was primarily due to Top Consumers. As described on page 14 of the 2014 Load Forecast, Top Consumers load was down 464 GW.h in 2013/14 compared to forecast due to a temporary equipment problem with one top consumer and an unexpected reduction of a second top consumer.

b) The 2010 forecast for GSL >100 in 2013/14 was 5,496 GW.h. The 2013/14 actuals were 4,222 GW.h resulting in a difference of 1,274 GW.h compared to the 2010 forecast. Approximately one half of this difference is due to delays in projects in the pipeline sector and slightly less than one third of the difference is due to one customer expansion not using as much energy as originally projected.

c) The GSL 30-100 kV rate classification has grown by 445 GWh over the last four years primarily as a result of growth in the pipeline sector. The GSL 30-100 kV rate classification currently includes approximately half of the pipeline sector loads. The forecast growth reflects a substantial portion of the expected growth in the pipeline sector.

d) Manitoba Hydro is projecting that approximately 90% of the new pipeline load will be within the GSL 30-100 kV rate classification with the remaining 10% expected to be within the GSL >100 kV rate classification.

Section:	Tab 9	Page No.:	MIPUG/MH I-8 MIPUG/MH I-9
Topic:	Energy Supply		
Subtopic:	Drought		
Issue:	Net Revenue Reductions		

PREAMBLE TO IR (IF ANY):

MIPUG/MH I-8 and I-9 indicate the net revenue reductions of a 5 year/7 year drought in 2016/17 and of historical events.

QUESTION:

a) Confirm that the 5 year and 7 year droughts depicted in MIPUG/MH I-8 reflect the following specific historical time periods:

- 5 year drought 1987/88 to 1991/92
- 7 year drought 1936/37 to 1942/43.

b) Confirm that both the 5 year and 7 year drought starting in 2016/17 reflect average lost sales and average incremental energy purchases at approximately 5¢/kWh.

c) Confirm that MH assumes no pricing premium in the MISO market during drought events.

RATIONALE FOR QUESTION:

To explore drought risk.

RESPONSE:

a) Confirmed.

b) Based on the data presented in MIPUG/MH-I-8, the average unit value of the combined effect of export sales and fuel & power purchases is approximately equal to:

- 5-year drought: 4.8¢/kWh
- 7-year drought 5.2¢/kWh

c) Manitoba Hydro's production costing analysis of drought events does not assume an increase in overall MISO market prices. A reduction in annual hydro generation in the order of 10,000 GWh in a severe drought is small in comparison to the annual energy demand in MISO, excluding the southern zones, of around 500,000 GWh. Manitoba Hydro's production costing analysis does account for increasing unit costs of imports as the volume of imports increases as a result of imports occurring in higher priced hours.

Section:	Tab 9	**Page No.:**	MIPUG/MH I-8 MIPUG/MH I-9
Topic:	Energy Supply		
Subtopic:	Drought		
Issue:	Net Revenue Reductions		

PREAMBLE TO IR (IF ANY):

MIPUG/MH I-8 and I-9 indicate the net revenue reductions of a 5 year/7 year drought in 2016/17 and of historical events.

QUESTION:

d) Does MH see a $1.5 to 2.0 Billion drought reserve as an adequate component of Retained Earnings? Explain in the context of the 1921/30 to 1942/43 extended low flow period.

RATIONALE FOR QUESTION:

To explore drought risk.

RESPONSE:

Manitoba Hydro assumes the time period 1929/30 to 1942/43 was intended in the question and has extended it an additional year to 1943/44 to continue to the end of the 20 year forecast in 2033/34 for the purposes of this response.

The sequence of 1929/30 to 1943/44 flow years commencing in load year 2016/17 through to 2033/34 results in net revenues that would be approximately $4 billion lower than the average revenues for all flow years over the 20-year forecast period. Retained earnings at the $1.5 to $2.0 billion level would clearly not be sufficient and would result in the requirement for significant rate increases to customers.

However, the fourteen year period from 1929/30 to 1942/43 represents the most severe extended low flow period in Manitoba Hydro's flow record and has a very low likelihood of reoccurrence.

Section:	Tab 7, Appendix 7.1	Page No.:	MMF/MH I-40 GAC/MH I-9
Topic:	Electric Load Forecast		
Subtopic:	Electric Heat Customers		
Issue:	Growth		

PREAMBLE TO IR (IF ANY):

MMF/MH I-40 data suggests the residential customer number growth over the last four years has been:

- 2.5%/yr. in Northern Manitoba
- 2.5%/yr. in non-gas Manitoba
- 6.0%/yr. in electric heat in gas-available Manitoba
- 1.4%/yr. in non-electric heat sector.

This compares with a projected 3.6%/yr. electric heat growth and less than 0.2%/yr. non-electric heat growth set out in GAC/MH I-9 over a three-year period.

QUESTION:

a) Please reconcile the 2013/14 customer numbers in MMF/MH I-40 with Table 14 in the 2014 load forecast.

b) Quantify the percent growth in forecast electric heat customer numbers in each of the test years and over the next ten years.

c) Explain the essentially zero-growth rate in non-electric heat customers in GAC/MH I-9.

RATIONALE FOR QUESTION:

To explore the assumptions made by Manitoba Hydro regarding load growth I the electric vs non-electric customer base.

RESPONSE:

a) The 2013/14 customers numbers presented in Table 14 in the 2014 Load Forecast were inadvertently not updated from the 2012/13 customer numbers during the preparation of the report. The 2013/14 historic customer numbers and corresponding energy is corrected in the following chart and are consistent with the information presented in Manitoba Hydro's response to MMF/MH-I-40:

Table 14 – Residential Basic Sales (Revised)

RESIDENTIAL BASIC SALES
History and Forecast
2013/14 - 2033/34

Fiscal Year	Electric Heat Billed			Non Electric Heat Billed			Total Basic			% Elec Space Heat	% Elec Water Heat
	Custs	GW.h	kW.h/cust	Custs	GW.h	kW.h/cust	Custs	GW.h	kW.h/cust		
2013/14	169,582	4,237	24,983	292,692	3,013	10,294	462,274	7,249	15,682	36.7%	48.3%
2014/15	173,561	4,324	24,913	294,514	3,056	10,377	468,075	7,380	15,767	37.1%	49.4%
2015/16	177,387	4,395	24,775	296,375	3,086	10,412	473,762	7,481	15,790	37.4%	50.5%
2016/17	181,184	4,474	24,693	298,780	3,132	10,484	479,964	7,606	15,848	37.7%	51.5%
2017/18	184,929	4,549	24,601	301,458	3,177	10,538	486,387	7,726	15,885	38.0%	52.3%
2018/19	188,478	4,618	24,501	304,222	3,218	10,577	492,700	7,836	15,904	38.3%	53.1%
2019/20	191,795	4,683	24,419	307,092	3,263	10,625	498,887	7,946	15,928	38.4%	53.8%
2020/21	194,868	4,743	24,341	310,046	3,306	10,663	504,914	8,049	15,942	38.6%	54.5%
2021/22	197,696	4,800	24,280	312,991	3,351	10,705	510,687	8,151	15,960	38.7%	55.1%
2022/23	200,277	4,853	24,230	315,883	3,396	10,749	516,160	8,248	15,980	38.8%	55.8%
2023/24	202,640	4,902	24,192	318,697	3,440	10,794	521,337	8,342	16,002	38.9%	56.4%
2024/25	204,859	4,951	24,167	321,424	3,485	10,842	526,283	8,435	16,028	38.9%	57.1%
2025/26	206,970	4,998	24,148	324,046	3,529	10,891	531,016	8,527	16,058	39.0%	57.7%
2026/27	208,970	5,044	24,140	326,547	3,575	10,947	535,517	8,619	16,095	39.0%	58.3%
2027/28	210,869	5,090	24,140	328,932	3,621	11,008	539,801	8,711	16,138	39.1%	59.0%
2028/29	212,686	5,135	24,145	331,228	3,667	11,071	543,914	8,802	16,183	39.1%	59.6%
2029/30	214,445	5,181	24,158	333,479	3,715	11,140	547,924	8,895	16,235	39.1%	60.2%
2030/31	216,165	5,226	24,176	335,713	3,764	11,212	551,878	8,990	16,290	39.2%	60.8%
2031/32	217,856	5,272	24,200	337,951	3,815	11,289	555,807	9,087	16,349	39.2%	61.4%
2032/33	219,528	5,319	24,228	340,203	3,868	11,369	559,731	9,186	16,412	39.2%	62.0%
2033/34	221,184	5,366	24,262	342,474	3,922	11,453	563,658	9,289	16,479	39.2%	62.6%

b) The following chart presents the projected growth rate forecast for Residential Basic electric heat customers for 2014/15, 2015/16 and over the next 10 years.

Residential Basic - Electric Heat

Fiscal Yr	# of Customers	Annual % Growth
2013/14	169,582	
2014/15	173,561	2.3%
2015/16	177,387	2.2%
		10 Year Avg. Annual Growth %
2023/24	202,640	1.8%

c) Analysis of the 2009 Residential Energy Use Survey indicated that Manitoba Hydro's customer information/billing database underestimated the number of customers with electric space heat. Based on this information, Manitoba Hydro undertook an initiative to correct its database to more accurately reflect customer's heating source. The information provided in Manitoba Hydro's response to GAC/MH-I-9 reflects the Corporation's customer database, including changes being made to reflect the corrections. As such, the growth rates reflected in the data provided in response to GAC/MH-I-9 are not an accurate representation of the actual growth rates taking place in the market.

Section:	Appendix 11.21 Revised	**Page No.:**	MFR
Topic:	Minimum Filing Requirements		
Subtopic:	Export Revenues		
Issue:	Opportunity Sales		

PREAMBLE TO IR (IF ANY):

Appendix 11.21, Table 3 is missing the 2014/15 column.

QUESTION:

Please add a column for 2014/15 to Table 3.

RATIONALE FOR QUESTION:

Missing data.

RESPONSE:

Please see the table below which revises Table 3 from Appendix 11.21 to include 2014/15.

	EXPORT REVENUES																				
	2008/09			2009/10			2010/11			2011/12			2012/13			2013/14			2014/15		
	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price	GWh	$M (Cdn)	Avg Price
Opportunity Bilateral Winter	357	29	70.79	489	18	38.30	970	26	27.15	685	21	29.39	658	24	36.36	508	22	42.38	301	12	39.46
Opportunity Bilateral Summer	948	72	71.57	2139	42	19.95	881	26	29.87	1238	29	23.55	1042	30	28.65	963	31	32.67	1055	31	30.22
Market Winter																					
Day Ahead	1087	41	37.80	1435	33	23.11	946	17	17.77	473	8	15.34	363	10	25.59	608	8	36.27	727	21	29.19
Real Time	322	20	53.81	771	32	32.17	846	23	25.59	734	18	22.44	393	10	27.66	422	13	45.51	303	11	29.83
Market Summer																					
Day Ahead	2953	81	27.58	1676	26	15.64	2287	52	22.88	2247	44	19.41	2184	43	19.56	3643	101	23.89	2669	64	23.97
Real Time	368	40	48.31	1087	39	23.97	1037	37	27.76	1125	32	23.74	810	26	25.21	914	19	24.81	612	14	24.59
Merchant Winter	720	38	48.36	361	12	30.96	275	10	33.20	118	5	22.37	61	3	33.46	202	28	80.90	169	6	35.49
Merchant Summer	878	48	47.84	414	14	25.98	437	17	39.27	318	12	34.79	89	6	34.66	129	5	28.68	240	8	33.35

2014/15 is to end of Dec/14

Section:	Tab 5: Appendix 5.7 Tab 10	**Page No.:**	Coalition/MH I-51
Topic:	Financial Results and Forecast		
Subtopic:	Accounting Policy & Estimate Changes		
Issue:	Impact of IFRS		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please describe the issues related to maintaining two different sets of financial records related to maintaining the current ASL procedure for rate-setting purposes.

b) Please indicate the number of schedules that would have to be maintained to reconcile between financial reporting and revenue requirement rate reporting.

RATIONALE FOR QUESTION:

To explore the impact of retaining the ASL methodology.

RESPONSE:

For the response to a) and b), please see Manitoba Hydro's response to PUB/MH-II-21c.

Section:	4	**Page No.:**	Coalition I-12c, PUB/MH I-10b Attachment b, PUB/MH I-75c
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Export Revenue		
Issue:	Changes in Economic Variables impact on IFF		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a graphical comparison of net export revenue based on IFF14 with PUB/MH I-10b Attachment b. Provide a schedule including the yearly comparison similar to that provided in PUB/MH I-5c.

b) Please update PUB/MH I-5c to include the new plot of gross and net export revenue based on PUB/MH I-10b attachment B.

c) Please provide a table of supporting data points for part (b).

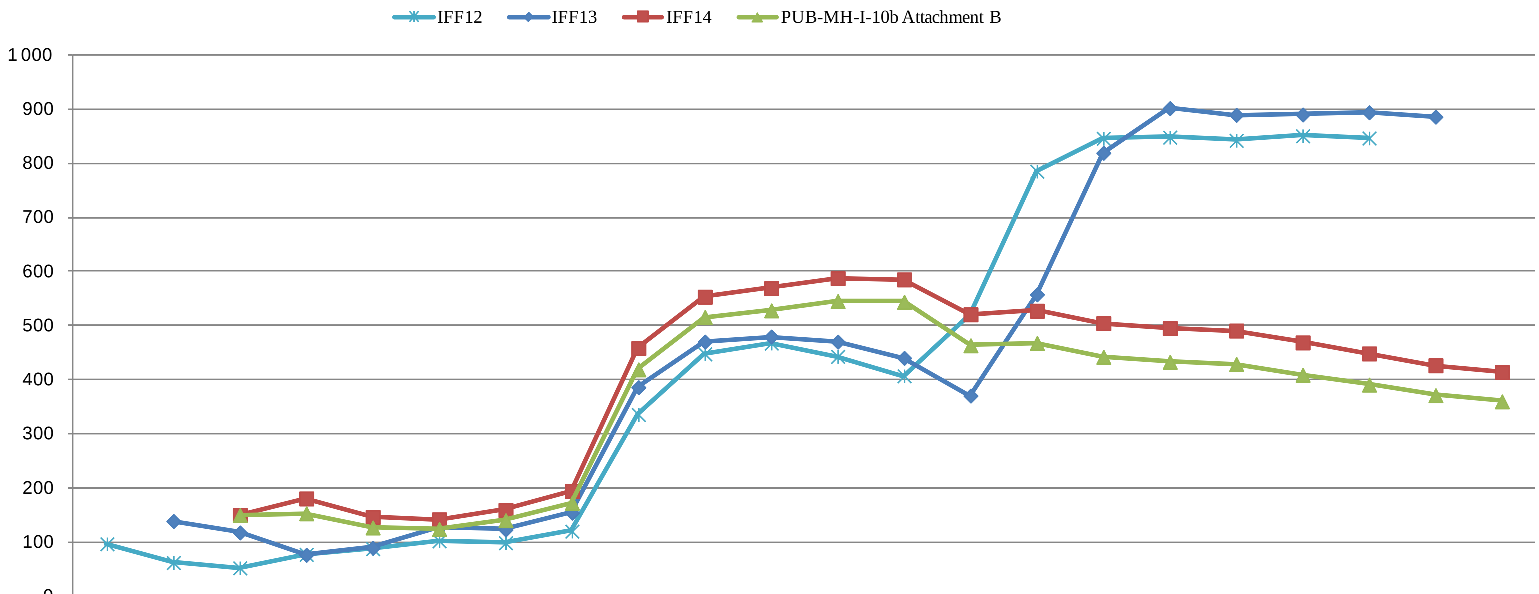
RATIONALE FOR QUESTION:

To assess changes in forecast assumptions.

RESPONSE:

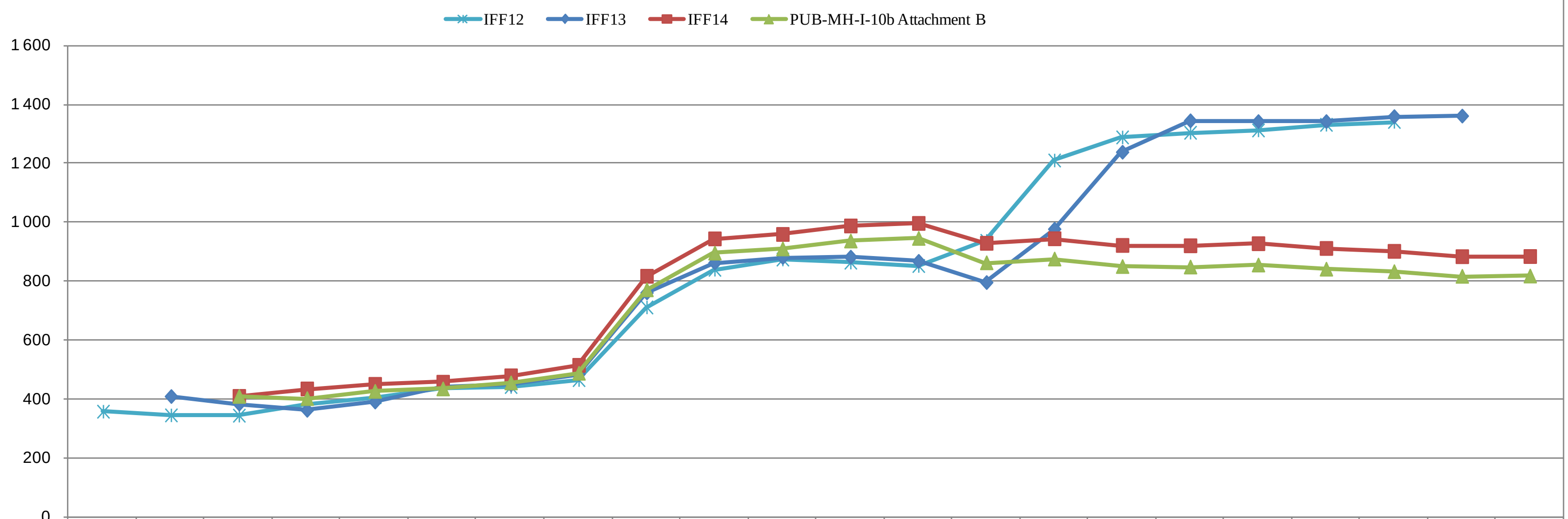
Please see the graphical comparisons of net export revenue and gross extraprovincial revenue between the scenario in PUB/MH-I-10b Attachment B with IFF14, IFF13 and IFF12. A schedule including the yearly comparison similar to that provided in PUB/MH-I-5c is also included below.

Net Extraprovincial Revenue



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IFF12	97	62	53	78	88	102	99	121	336	448	468	443	407	522	786	846	848	843	851	847		
IFF13		139	118	77	90	127	124	155	386	471	480	471	441	371	558	819	902	890	890	894	886	
IFF14			150	181	147	142	160	195	459	554	569	588	586	521	528	505	496	491	469	449	427	414
PUB-MH-I-10b Attachment B			150	153	127	124	141	173	419	516	528	546	544	464	468	443	433	429	409	391	372	360

Gross Extraprovincial Revenue



	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IFF12	357	344	343	380	406	435	441	464	711	839	873	863	851	937	1 209	1 288	1 304	1 312	1 331	1 341		
IFF13		408	383	362	390	441	448	484	760	862	880	881	867	795	976	1 238	1 344	1 342	1 342	1 358	1 360	
IFF14			409	434	450	457	479	514	817	943	959	987	996	928	944	921	920	927	911	901	883	884
PUB-MH-I-10b Attachment B			409	402	426	434	455	487	771	895	909	936	945	862	875	850	848	855	841	832	816	817

Gross Extraprovincial Revenue

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IFF14	409	434	450	457	479	514	817	943	959	987	996	928	944	921	920	927	911	901	883	884
PUB-MH-I-10b Attachment B	409	402	426	434	455	487	771	895	909	936	945	862	875	850	848	855	841	832	816	817
Annual Change	0	33	24	23	24	27	46	48	49	51	51	66	69	72	72	72	70	69	67	66
Cumulative Change	0	33	56	79	103	130	176	224	273	324	375	441	510	582	654	726	796	865	932	998

Net Extraprovincial Revenue

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IFF14	150	181	147	142	160	195	459	554	569	588	586	521	528	505	496	491	469	449	427	414
PUB-MH-I-10b Attachment B	150	153	127	124	141	173	419	516	528	546	544	464	468	443	433	429	409	391	372	360
Annual Change	0	28	19	18	19	22	39	37	41	42	41	57	60	62	62	62	60	58	55	54
Cumulative Change	0	28	47	65	84	106	145	182	223	266	307	364	424	486	548	610	670	727	783	837

Section:	Tab 3: Appendix 3.7	**Page No.:**	Coalition I-12c, PUB/MH I-10b Attachment b, PUB/MH I-75c
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Export Revenue		
Issue:	Changes in Export Revenue		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a table comparing all economic variables used in PUB/MH I-10b attachment b with those used in IFF14.

RATIONALE FOR QUESTION:

To test the impact of changes to other economic variables on the analysis provided in PUB/MH I-10b.

RESPONSE:

The interest rate impact arising from the update scenarios in PUB/MH-I-10b were primarily driven by changes in the Canadian short and long term interest rates, with a comparison found in the response to PUB/MH-I-75c.

Please also see the response to PUB/MH-II-83a for the comparison of the average unit export revenues included in PUB/MH-I-10b.

Section:	Tab 3: Appendix 3.7	Page No.:	Coalition I-12c, PUB/MH I-10b Attachment b, PUB/MH I-75c
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Export Revenue		
Issue:	Changes in Export Revenue		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please indicate whether PUB/MH I-10b Attachment b incorporates all the changes in all economic variables listed in COALITION/MH I-12c. If not, please update the analysis PUB/MH I 10b attachment B.

RATIONALE FOR QUESTION:

To test the impact of changes to other economic variables on the analysis provided in PUB/MH I-10b.

RESPONSE:

The scenario provided in PUB/MH-I-10b Attachment B assumes no change to interest rates in 2014/15, but assumes the interest rates shown in COALITION/MH-I-12c for 2015/16 and 2016/17.

The scenario provided in PUB/MH-I-10b did not include a change in assumptions for the USD/CAD exchange rate as the revenue requirement fluctuations associated with this economic variable have been largely eliminated due to the combination of natural and accounting hedges (see Manitoba Hydro's response to COALITION/MH-I-103a.

Section:	Tab 3: Appendix 3.7	**Page No.:**	Coalition I-12c, PUB/MH I-10b Attachment b, PUB/MH I-75c
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Export Revenue		
Issue:	Changes in Export Revenue		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a yearly comparison of IFF14 income statement, cash flow statement and balance sheet with PUB/MH I-10b Attachment B over the twenty-year forecast.

RATIONALE FOR QUESTION:

To test the impact of changes to other economic variables on the analysis provided in PUB/MH I-10b.

RESPONSE:

Please see the attached comparison of projected financial statements between PUB/MH-I-10b Attachment B and MH14.

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
Response to PUB-II-82 c - Comparison of PUB-MH-I-10b Attachment B less MH14
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
at approved rates	-	-	-	-	-	-	-	-	-	-
additional*	-	-	-	-	-	-	-	-	-	-
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Extraprovincial	-	(33)	(24)	(23)	(24)	(27)	(46)	(48)	(49)	(51)
Other	-	-	-	-	-	-	-	-	-	-
	-	(33)	(24)	(23)	(24)	(27)	(46)	(48)	(49)	(51)
EXPENSES										
Operating and Administrative	-	-	-	-	-	-	-	-	-	-
Finance Expense	-	(13)	(28)	(28)	(35)	(46)	(67)	(86)	(90)	(92)
Depreciation and Amortization	-	0	0	0	0	(0)	(1)	(1)	(1)	(1)
Water Rentals and Assessments	-	-	-	-	-	-	-	-	0	0
Fuel and Power Purchased	-	(5)	(4)	(5)	(5)	(5)	(7)	(11)	(8)	(9)
Capital and Other Taxes	-	0	(0)	(0)	(0)	(0)	(0)	0	0	(0)
Corporate Allocation	-	-	-	-	-	-	-	-	-	-
Other Expenses	-	-	-	-	-	-	-	-	-	-
	-	(18)	(32)	(33)	(41)	(51)	(74)	(98)	(99)	(102)
Non-controlling Interest	-	(0)	(1)	(0)	(0)	(0)	(3)	(0)	(0)	(0)
Net Income	-	(15)	8	10	16	24	25	49	50	51
* Additional General Consumers Revenue										
Percent Increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Cumulative Percent Increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Financial Ratios										
Equity	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%
Interest Coverage	0.00	(0.02)	0.01	0.02	0.01	0.01	0.02	0.02	0.03	0.03
Capital Coverage	0.00	(0.04)	0.00	0.02	0.03	0.06	0.05	0.09	0.09	0.09

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
Response to PUB-II-82 c - Comparison of PUB-MH-I-10b Attachment B less MH14
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
at approved rates	-	-	-	-	-	-	-	-	-	-
additional*	-	-	-	-	-	-	-	-	-	-
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Extraprovincial	(51)	(66)	(69)	(72)	(72)	(72)	(70)	(69)	(67)	(66)
Other	-	-	-	-	-	-	-	-	-	-
	(51)	(66)	(69)	(72)	(72)	(72)	(70)	(69)	(67)	(66)
EXPENSES										
Operating and Administrative	-	-	-	-	-	-	-	-	-	-
Finance Expense	(93)	(94)	(97)	(97)	(97)	(99)	(98)	(100)	(99)	(92)
Depreciation and Amortization	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Water Rentals and Assessments	0	0	0	0	0	0	0	0	0	0
Fuel and Power Purchased	(10)	(9)	(9)	(9)	(10)	(11)	(11)	(11)	(11)	(12)
Capital and Other Taxes	0	0	0	0	1	1	1	1	(1)	(0)
Corporate Allocation	-	-	-	-	-	-	-	-	-	-
Other Expenses	-	-	-	-	-	-	-	-	-	-
	(104)	(104)	(107)	(107)	(108)	(111)	(109)	(112)	(112)	(106)
Non-controlling Interest	(0)	0	0	0	0	0	0	0	0	0
Net Income	53	38	39	35	36	38	39	43	46	40
* Additional General Consumers Revenue										
Percent Increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Cumulative Percent Increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Financial Ratios										
Equity	1%	1%	1%	2%	2%	2%	2%	2%	2%	3%
Interest Coverage	0.04	0.03	0.04	0.04	0.04	0.06	0.06	0.09	0.10	0.11
Capital Coverage	0.08	0.06	0.06	0.06	0.04	0.05	0.05	0.06	0.06	0.06

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
Response to PUB-II-82 c - Comparison of PUB-MH-I-10b Attachment B less MH14
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	-	0	0	0	0	(28)	(66)	(66)	(66)	(66)
Accumulated Depreciation	-	(0)	(0)	(0)	(0)	0	1	2	3	3
Net Plant in Service	-	0	0	0	0	(28)	(65)	(64)	(63)	(62)
Construction in Progress	-	(6)	(20)	(37)	(56)	(44)	(9)	-	-	-
Current and Other Assets	-	(0)	(1)	(2)	(12)	(7)	(14)	(20)	(32)	(33)
Goodwill and Intangible Assets	-	(0)	(0)	(1)	(3)	(5)	(6)	(6)	(6)	(6)
Regulated Assets	-	-	-	-	-	-	-	-	-	-
	-	(6)	(22)	(40)	(70)	(84)	(94)	(90)	(101)	(102)
LIABILITIES AND EQUITY										
Long-Term Debt	-	-	-	-	-	(200)	(200)	(200)	(200)	(200)
Current and Other Liabilities	-	9	(15)	(42)	(89)	73	38	(7)	(68)	(120)
Contributions in Aid of Construction	-	-	-	-	-	-	-	-	-	-
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	-	(15)	(7)	3	19	43	68	117	167	218
Accumulated Other Comprehensive Income	-	-	-	-	-	-	-	-	-	-
	-	(6)	(22)	(40)	(70)	(84)	(94)	(90)	(101)	(102)

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
Response to PUB-II-82 c - Comparison of PUB-MH-I-10b Attachment B less MH14
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)
Accumulated Depreciation	4	5	6	7	8	9	10	11	12	12
Net Plant in Service	(61)	(61)	(60)	(59)	(58)	(57)	(56)	(55)	(54)	(53)
Construction in Progress	-	-	-	-	-	0	-	-	-	0
Current and Other Assets	(24)	(35)	8	185	77	114	152	194	241	279
Goodwill and Intangible Assets	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
Regulated Assets	-	-	-	-	-	-	-	-	-	-
	(92)	(102)	(58)	120	13	51	90	133	181	220
LIABILITIES AND EQUITY										
Long-Term Debt	(200)	(400)	(400)	(200)	(400)	(400)	(400)	(400)	(400)	(400)
Current and Other Liabilities	(163)	(11)	(6)	(63)	(6)	(7)	(7)	(7)	(5)	(6)
Contributions in Aid of Construction	-	-	-	-	-	-	-	-	-	-
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	271	309	348	383	419	457	496	540	585	626
Accumulated Other Comprehensive Income	-	-	-	-	-	-	-	-	-	-
	(92)	(102)	(58)	120	13	51	90	133	180	220

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
Response to PUB-II-82 c - Comparison of PUB-MH-I-10b Attachment B less MH14
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	-	(33)	(24)	(23)	(24)	(27)	(46)	(48)	(49)	(51)
Cash Paid to Suppliers and Employees	-	5	4	5	5	5	7	7	8	9
Interest Paid	-	7	24	31	35	55	70	91	90	93
Interest Received	-	(0)	(1)	(1)	(2)	(1)	(1)	(1)	(1)	(1)
	-	(20)	4	12	14	32	30	49	48	50
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	-	-	-	-	10	(210)	-	-	10	-
Sinking Fund Withdrawals	-	-	-	0	-	(0)	(1)	(1)	-	(1)
Retirement of Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Other	-	0	0	0	0	0	0	0	0	0
	-	0	0	0	10	(210)	(1)	(1)	10	(1)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	-	5	13	15	18	21	7	-	-	-
Sinking Fund Payment	-	-	(0)	0	0	1	1	1	2	3
Other	-	-	-	-	-	-	-	-	-	-
	-	5	13	15	18	22	8	1	2	3
Net Increase (Decrease) in Cash	-	(15)	17	28	43	(156)	38	49	60	52
Cash at Beginning of Year	-	0	(15)	2	30	72	(84)	(46)	3	63
Cash at End of Year	-	(15)	2	30	72	(84)	(46)	3	63	115

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
Response to PUB-II-82 c - Comparison of PUB-MH-I-10b Attachment B less MH14
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	(51)	(66)	(69)	(72)	(72)	(72)	(70)	(69)	(67)	(66)
Cash Paid to Suppliers and Employees	9	9	9	9	9	10	10	11	12	12
Interest Paid	92	98	100	105	99	106	106	107	107	102
Interest Received	(1)	(2)	(3)	(4)	(6)	(7)	(8)	(7)	(8)	(10)
	49	39	37	38	31	37	38	42	45	39
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	(10)	(190)	-	200	(190)	-	(10)	10	-	-
Sinking Fund Withdrawals	(2)	(2)	-	-	-	-	-	-	-	-
Retirement of Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Other	0	0	0	0	0	0	0	0	0	0
	(11)	(192)	0	200	(190)	0	(10)	10	0	0
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	-	-	-	-	-	0	-	-	(0)	-
Sinking Fund Payment	3	3	3	4	4	5	5	5	5	6
Other	-	-	-	-	-	-	-	-	-	-
	3	3	3	4	4	5	5	5	5	6
Net Increase (Decrease) in Cash	40	(150)	41	242	(156)	42	33	57	50	44
Cash at Beginning of Year	115	155	6	46	288	133	175	208	265	315
Cash at End of Year	155	6	46	288	133	175	208	265	315	360

Section:	3	**Page No.:**	PUB/MH I-10b Attachment b, PUB/MH I-14 (a)
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Export Revenue		
Issue:	Average Unit Export Revenue Changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a graphical comparison of average unit export prices comparing IFF14 with those included in PUB/MH I-10b Attachment B in a similar format as MH Exhibit #36 from the 2012/13 and 2013/14 GRA.

b) Update the response to PUB/MH I-14(a) to include the additional plot reflecting PUB/MH I-10b Attachment B.

c) Please include a table of the supporting data points for (b).

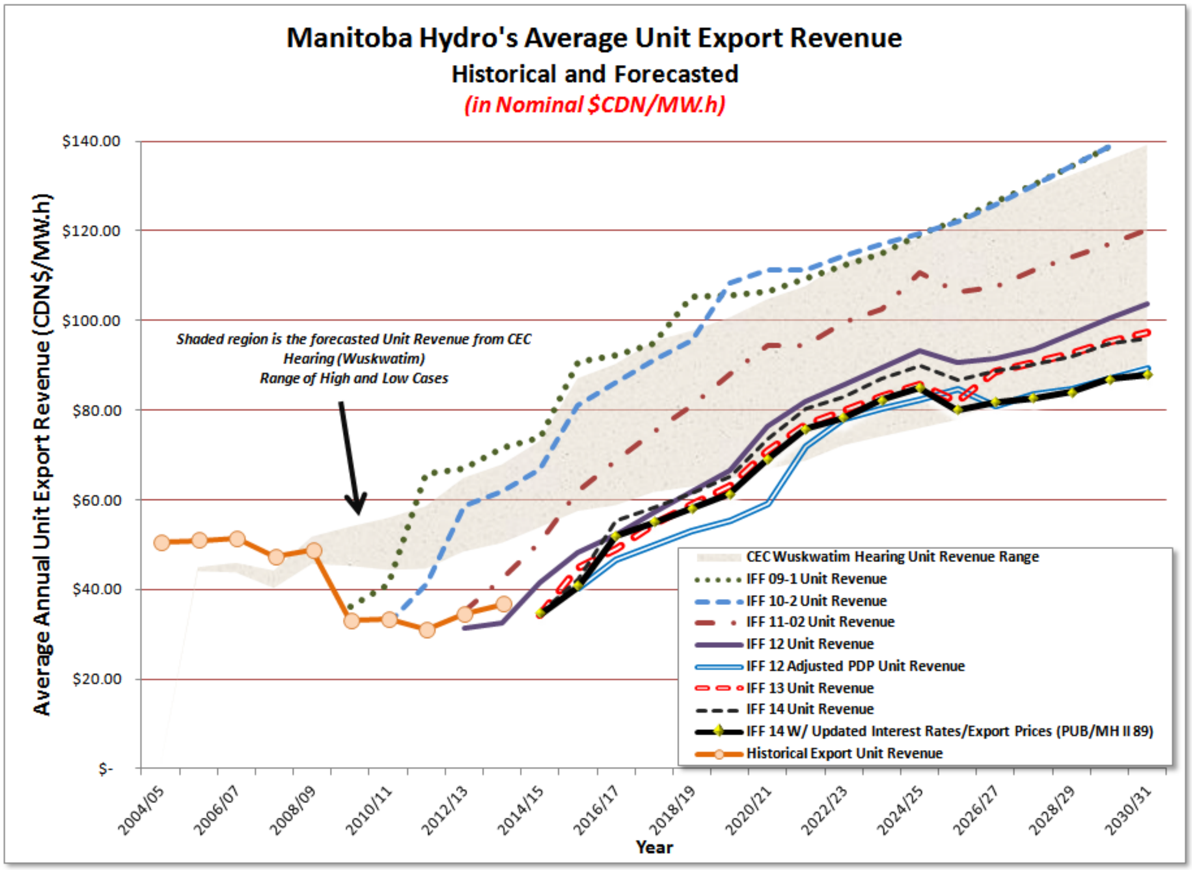
RATIONALE FOR QUESTION:

To assess changes the impact of changes in forecast assumptions.

RESPONSE:

a-b) The below chart is in the same format as the chart provided in Manitoba Hydro's response to PUB/MH-I-14a and Exhibit #36 from the 2012/13 and 2013/14 GRA, updated to include the additional information requested.

c) The below table provides the data displayed in the chart referenced in part a) - b).



Year	IFF 14 w/ Updated Interest Rates/Export Prices (PUB/MH II 89)	IFF 14	IFF 13	IFF 12 Adjusted PDP Unit Revenue	IFF 2012	IFF 2011-2	IFF 2010-2	IFF 2009-1	CEC Wuskwatim Hearing Unit Revenue Range Low	CEC Wuskwatim Hearing Unit Revenue Range High	Historical Export Unit Revenue
	All figures below in nominal CDN Dollars/MWh										
2004/05											$ 50.51
2005/06									$ 44.18	$ 45.05	$ 50.98
2006/07									$ 43.88	$ 46.04	$ 51.38
2007/08									$ 40.41	$ 44.29	$ 47.36
2008/09									$ 45.81	$ 51.85	$ 48.85
2009/10								$ 36.24	$ 45.37	$ 54.09	$ 32.99
2010/11							$ 32.58	$ 41.02	$ 44.46	$ 56.03	$ 33.31
2011/12							$ 41.38	$ 65.90	$ 44.71	$ 58.65	$ 31.10
2012/13					31.36	$ 35.14	$ 58.65	$ 66.89	$ 48.57	$ 64.98	$ 34.50
2013/14					32.61	$ 42.50	$ 61.99	$ 71.71	$ 50.45	$ 67.93	$ 36.71
2014/15	$ 34.67	$ 34.67	$ 34.29		41.63	$ 50.44	$ 66.77	$ 73.93	$ 53.95	$ 73.17	
2015/16	$ 40.73	$ 42.39	$ 44.88		48.14	$ 61.85	$ 81.14	$ 90.87	$ 57.60	$ 87.17	
2016/17	$ 52.02	$ 55.31	$ 49.00	$ 46.72	52.36	$ 68.78	$ 86.38	$ 92.31	$ 58.88	$ 90.37	
2017/18	$ 55.01	$ 58.28	$ 54.63	$ 49.78	57.23	$ 75.34	$ 91.09	$ 94.95	$ 61.83	$ 95.45	
2018/19	$ 58.04	$ 61.50	$ 58.91	$ 53.02	61.78	$ 81.14	$ 95.64	$ 105.31	$ 63.05	$ 97.78	
2019/20	$ 61.30	$ 65.11	$ 63.00	$ 55.49	66.52	$ 88.14	$ 108.41	$ 105.56	$ 64.71	$ 100.74	
2020/21	$ 69.14	$ 73.67	$ 70.86	$ 59.16	76.5	$ 94.29	$ 111.15	$ 106.50	$ 66.92	$ 104.82	
2021/22	$ 75.77	$ 80.20	$ 76.59	$ 72.04	81.96	$ 96.42	$ 111.26	$ 109.40	$ 68.82	$ 107.73	
2022/23	$ 78.22	$ 82.80	$ 79.78	$ 77.93	85.61	$ 99.78	$ 114.61	$ 112.30	$ 72.27	$ 113.04	
2023/24	$ 82.25	$ 87.12	$ 83.02	$ 80.46	89.62	$ 102.52	$ 117.11	$ 114.90	$ 74.22	$ 115.73	
2024/25	$ 85.02	$ 89.98	$ 85.58	$ 82.38	93.22	$ 110.63	$ 119.56	$ 119.40	$ 76.07	$ 118.48	
2025/26	$ 80.01	$ 86.71	$ 81.97	$ 84.78	90.57	$ 106.34	$ 121.99	$ 122.50	$ 77.98	$ 121.44	
2026/27	$ 81.80	$ 88.83	$ 88.51	$ 80.77	91.39	$ 107.62	$ 125.80	$ 126.40	$ 81.58	$ 126.28	
2027/28	$ 82.57	$ 90.19	$ 90.58	$ 83.50	93.48	$ 111.41	$ 130.04	$ 130.40	$ 83.62	$ 129.44	
2028/29	$ 84.00	$ 91.84	$ 92.64	$ 84.82	97.02	$ 114.06	$ 134.50	$ 134.50	$ 85.71	$ 132.52	
2029/30	$ 86.83	$ 94.91	$ 95.30	$ 87.15	100.42	$ 117.21	$ 138.94	$ 138.60	$ 88.02	$ 135.83	
2030/31	$ 87.93	$ 96.09	$ 97.27	$ 89.25	103.65	$ 120.27			$ 90.38	$ 139.23	

Section:	10	**Page No.:**	PUB/MH I-84(a),Appendix 11.7
Topic:	PUB Directives and Interim Orders		
Subtopic:	Order 43/13 Directive 10		
Issue:	Risk Quantification		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please indicate for each of the risks listed in the Corporate Risk Management report whether they have financial consequences and whether such consequences can be measured.

RATIONALE FOR QUESTION:

To understand how MH will address Board directives related to risk.

RESPONSE:

a) All the risks listed in the Corporate Risk Management Report ultimately have financial consequences, however not all financial consequences can be reasonably quantified.

The Sensitivity Analysis included in IFF14 (Appendix 3.2, page 22) discusses changes in key risk factors that could have a significant impact on projected financial results. These factors include domestic load growth, interest rates, foreign exchange rates, export prices, capital expenditures, water flow conditions and rate increases.

Section:	10	Page No.:	PUB/MH I-84(a),Appendix 11.7
Topic:	PUB Directives and Interim Orders		
Subtopic:	Order 43/13 Directive 10		
Issue:	Risk Quantification		

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please confirm that KPMG will have access to the Corporate Risk Management report and will address all quantifiable risks and risk mitigation measures. If not, please explain.

RATIONALE FOR QUESTION:

To understand how MH will address Board directives related to risk.

RESPONSE:

It is confirmed that KPMG has access to the Corporate Risk Management report. The terms of reference for the engagement provided in the response to PUB/MH-I-84d requested that the KPMG analysis address the PUB directive to review Manitoba Hydro's operating and financial risks as part of KPMG's review of Manitoba Hydro's financial targets, including, as appropriate, the use of quantitative and probabilistic analysis with respect to significant risk factors impacting the financial outlook of the Corporation. Looking at all quantifiable risks is not realistic and not practical.

Manitoba Hydro expects that when complete, the final KPMG report will address the items contained in the terms of reference for the engagement. KPMG's review is currently underway and as such, Manitoba Hydro is not in a position to comment on what will be contained in the final report. KPMG will be in a position to provide information on their final report and the analysis undertaken to address the PUB directive at a future PUB proceeding.

Section:	App. 11.7	**Page No.:**	P3.
Topic:	Corporate Risk Management Report		
Subtopic:	Infrastructure Risk		
Issue:	Prolonged Loss of Supply		

PREAMBLE TO IR (IF ANY):

MH has indicated that the potential financial impact of a prolonged loss of supply is greater than $2 billion.

QUESTION:

a) Provide the analysis of specific infrastructure failure of generation or transmission failure that could result in a $2 billion financial impact.

b) Separately indicate the cost of restoring the infrastructure in service and the lost revenues associated with the failure.

RATIONALE FOR QUESTION:

To understand how the $2 billion financial impact was determined.

RESPONSE:

a) As per the attached response to CAC/MSOS/MH II–111(a) from the 2010/11 & 2011/12 GRA, the potential financial impact of greater than $2 billion is based on a scenario where a major facility was out of service for an extended period resulting in a loss of generation and the need to purchase imported power and fuel to meet firm commitments. This resulted in a reduction to net export revenues, increased power and fuel costs and reduced water rental. The impact increases to above $2.0 billion over the next ten years due to financing costs. The IFF risk scenario is provided in Attachment 2 of CAC/MSOS/MH II-111(a).

b) The scenario discussed in response to CAC/MSOS/MH II-111a) from the 2010/11 & 2011/12 GRA assumes a zero cost of restoring the infrastructure and a reduction of $.2 billion in net export revenues. The major other costs are $1.0 billion for increased power and fuel and $1.0 billion for financing.

CAC/MSOS/MH II-111

Subject: **Risk**
Reference: **CAC/MSOS/MH I – 114(a)**

Preamble: **With respect, the reply to CAC/MSOS/MH I – 114(a) was unresponsive. CAC/MSOS requested calculations to support MH's quantification of risk contained in document filed in the current GRA. CAC/MSOS did not ask descriptions provided. Rather it specifically requested the mechanical calculations together with assumptions used in those calculations.**

a) **Please provide the requested calculations together with a complete list of assumptions.**

ANSWER:

As noted in the response to CAC/MSOS/MH I-114(a), the quantification of the risks listed in the Risk Management section of The Manitoba Hydro-Electric Board 58th Annual Report is based on the Risk Analysis section of the 2008 Integrated Financial Forecast (see Appendix 21), with the exception of infrastructure risk. Further explanation of the assumptions and methodology used are provided below. Copies of the IFF risk scenarios supporting the risk quantification are also attached. Please note that the provision of further detailed calculations is not possible to replicate as the IFF model is formula driven and performs multiple reiterations in arriving at results.

Drought - $2.2 Billion net reduction in export revenues

As described on p. 20 of IFF 08 under water conditions,

"A drought sensitivity has been prepared based on an assumed recurrence of the worst five year drought on record. This drought sensitivity replicates the water flows of the historic five year drought period between April 1987 and March 1992 beginning in the forecast year 2010/11 and extending to 2014/2015. The impacts of the drought on export revenues and thermal and import costs assume expected market conditions. Over the five year drought period, net export revenue would be reduced by $2.2 billion compared to IFF08-1. The impact could be greater due to financing costs and will be dependent upon the timing and magnitude of the rate increases implemented to address the drought impacts. If a drought of this magnitude (or the even larger 1936 - 1943 drought) were to coincide with a period of high prices for thermal and import purchases the impact would be even greater." See the attached IFF08 risk scenario for drought on page 2 of Attachment 1.

Loss of export market - Up to 30% of electric revenues

This simply represents a total loss of export sales which is approximately 30% of base case forecasted electric revenues.

Interest Rates - Up to $115 million for a 1% change over a 10 year period

As described on p. 19 of IFF08, 1% changes in interest rates were applied to all new long and short-term debt issues and to new sinking fund instruments. The worst case impact over as 10 year period is $115 million, as shown on the table on p. 18. See the attached IFF08 risk scenario for interest rates on page 3 of Attachment 1.

Foreign Exchange Rates - Up to $144 million for a $.10 US change over a 10 year period

US exchange rate changes of $.10 were applied to forecast US dollar revenues, fuel and power purchases, and interest payments. The worst case impact over a ten year period is $144 million, as shown in the table on p. 18 of IFF08. See the attached IFF08 risk scenario for interest rates on page 4 of Attachment 1.

Infrastructure - Greater than $2.0 billion for a major facility long term outage

This is based on a worst case scenario where a major facility was out of service for an extended period resulting in a loss of generation and the need to purchase imported power and fuel for meet firm commitments. This resulted in a reduction to net export revenues, increased power and fuel costs and reduced water rental. The impact increases to above $2.0 billion over the next ten years due to financing costs. See the attached IFF risk scenario for major power shortage on attachment 2.

ELECTRIC OPERATIONS (MH03-1)
PROJECTED OPERATING STATEMENT
Base Case
(In millions of dollars)

For year ending March 31:	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
REVENUES:											
General Consumers Revenue											
at approved rates	901	917	923	931	939	946	953	960	968	976	985
additional *	-	28	51	77	103	130	158	187	217	249	282
Extraprovincial	394	451	430	435	448	480	491	583	621	653	660
Other	8	7	7	7	7	7	7	7	8	8	8
	1,303	1,403	1,411	1,450	1,497	1,563	1,609	1,737	1,814	1,886	1,935
EXPENSES:											
Finance Expense	471	504	529	539	565	579	582	639	666	662	638
Depreciation	274	288	298	309	323	336	342	361	374	382	390
Cost of Operations	304	307	309	315	321	330	337	348	355	362	370
Water Rentals	79	104	99	98	98	99	99	102	104	104	104
Tax Expense	51	53	55	58	60	62	64	65	65	65	65
Fuel & Power Purchased	480	106	91	101	112	127	141	143	150	160	169
	1,659	1,362	1,381	1,420	1,479	1,533	1,565	1,658	1,714	1,735	1,736
Noncontrolling Interest	-	-	-	-	-	-	-	(2)	(5)	(7)	(9)
Net Income (Loss)	(356)	41	30	30	18	30	44	77	95	144	190

ELECTRIC OPERATIONS (MH03-1)
PROJECTED OPERATING STATEMENT
Major Power Shortage in 2004/2005
(In millions of dollars)

For year ending March 31:	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	
REVENUES:												
General Consumers Revenue												
at approved rates	901	917	923	931	939	946	953	960	968	976	985	
additional *	-	28	51	77	103	130	158	187	217	249	282	
Extraprovincial	394	293	430	435	448	480	491	583	621	653	660	
Other	8	7	7	7	7	7	7	7	8	8	8	
	1,303	1,245	1,411	1,450	1,497	1,563	1,609	1,737	1,814	1,886	1,935	
EXPENSES:												
Finance Expense	471	524	581	593	663	688	699	766	802	805	796	
Depreciation	274	288	298	309	323	336	342	361	374	382	390	
Cost of Operations	304	307	309	315	321	330	337	348	355	362	370	
Water Rentals	79	-	99	98	98	99	99	102	104	104	104	
Tax Expense	51	53	55	58	61	63	64	65	65	66	66	
Fuel & Power Purchased	480	1,151	91	101	112	127	141	143	150	160	169	
	1,659	2,323	1,433	1,474	1,578	1,643	1,682	1,785	1,850	1,879	1,895	
Noncontrolling Interest	-	-	-	-	-	-	-	(2)	(5)	(7)	(9)	
Net Income (Loss)	(356)	(1,078)	(22)	(24)	(81)	(80)	(73)	(50)	(41)	-	31	
Net Income (Loss) - Change from base case	-	(1,119)	(52)	(54)	(99)	(110)	(117)	(127)	(136)	(144)	(159)	(2,117)

Section:	App. 11.7	**Page No.:**	Pg. 3, Pg.21
Topic:	Corporate Risk Management Report		
Subtopic:	Loss of Export Market Access		
Issue:	MISO Rule Changes		

PREAMBLE TO IR (IF ANY):

MH has indicated a potential financial impact of loss of export market access of greater than 30% of electricity revenues.

QUESTION:

a) Confirm that this risk also includes possible MISO rule changes alluded to on page 21.

b) Please indicate to what extent the risk of lost market access relates to long-term firm contracts versus day-ahead or real-time MISO market sales and quantify the financial impact by sale type.

RATIONALE FOR QUESTION:

To explore risk related to export market access.

RESPONSE:

a) Confirmed. Corporate risk profile A.2.1 Export Regulatory Environment, as referenced on page 21 of Appendix 11.7 of the Application, pertains to regulatory and industry business environment barriers that could limit access to both US and Canadian power markets. Therefore, the Export Regulatory Environment risk includes any power market rules changes, in Canada or the US, including MISO rule changes, which would limit Manitoba Hydro's access to power markets.

b) Corporate risk profile A.2.1 Export Regulatory Environment pertains to long-term firm contracts, day-ahead and real-time MISO market sales, including real time sales to Canadian markets. The potential financial impact of > 30% of electricity revenue for a loss of export market access as stated on page 3 of Appendix 11.7 pertains to a very low probability event that results in a complete loss of all export markets on all time horizons.

Section:	Appendix 11.19(IFF14) Appendix 11.21 Revised	Page No.:	MFR 1 MFR 4
Topic:	Export Revenues		
Subtopic:	Unit Export Revenues		
Issue:	Average Flow Year Unit Revenue		

PREAMBLE TO IR (IF ANY):

MH has suggested that average flow year unit export prices would be higher than historical because Manitoba Hydro would reduce low-value sales.

QUESTION:

a) Re-file Table 5 from Appendix 11.21 eliminating all winter off-peak opportunity sales at prices indicated in Table 7 and recalculate the average unit opportunity export revenues.

b) Recalculate the average total unit export annual revenues for 2005/06 to 2014/15 assuming no winter off-peak sales.

RATIONALE FOR QUESTION:

To explore the impact of low-flow years on export prices.

RESPONSE:

a) Below is the revised Table 5 from Appendix 11.21 with all off-peak opportunity sales removed from the GWh, Revenue and Average Price for Opportunity Sales only. The data shown for Opportunity Sales has off peak sales removed for both seasons rather than just the winter season so that a fair comparison between summer and winter can be made. Just removing off peak from the winter period and not the summer would result in a misleading comparison.

TOTAL SALES									
	DEPENDABLE SALES			OPPORTUNITY SALES			SYSTEM MERCHANT SALES		
	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice	GWh	CAD $M	AvgPrice
2005/06 Winter	1,805	107	59.39	1,329	95	67.91	505	31	54.78
2005/06 Summer	2,239	133	59.14	1,813	150	76.48	414	32	66.51
2006/07 Winter	1,654	103	62.51	463	33	66.44	573	29	45.12
2006/07 Summer	2,000	115	57.32	1,509	102	66.08	633	31	41.81
2007/08 Winter	1,548	87	56.02	714	53	67.42	636	39	53.24
2007/08 Summer	2,373	122	51.39	1,498	109	65.84	626	33	45.03
2008/09 Winter	1,537	100	64.81	525	44	71.42	719	38	48.36
2008/09 Summer	2,550	133	52.49	1,277	109	72.13	879	48	47.84
2009/10 Winter	1,383	83	59.73	972	34	34.80	359	13	30.96
2009/10 Summer	1,880	103	54.98	1,525	50	29.00	383	12	25.98
2010/11 Winter	1,248	70	55.9	889	25	28.86	275	10	33.20
2010/11 Summer	2,129	102	48.27	1,379	51	33.93	437	17	39.27
2011/12 Winter	1,592	78	49.14	635	19	26.92	118	5	22.37
2011/12 Summer	2,150	97	45.05	1,317	40	28.68	318	12	34.79
2012/13 Winter	1,544	79	51.35	662	22	32.83	61	3	33.46
2012/13 Summer	2,092	98	46.72	1,503	47	28.60	89	6	34.66
2013/14 Winter	1,426	82	57.65	652	23	45.18	202	28	80.90
2013/14 Summer	2,053	100	48.45	1,840	59	33.87	129	6	28.68
2014/15 Winter	665	41	61.94	535	22	38.59	168	5	35.49
2014/15 Summer	1,904	99	52.05	1,254	45	33.00	241	9	33.35
2014/15 is to end of Dec 2014									

b) The total average export price for 2005/07 to 2014/15 excluding all opportunity off-peak sales is provided below.

	Total Avg Unit Price excluding All Opportunity Off Peak Sales
2005/06	65.00
2006/07	61.91
2007/08	58.46
2008/09	62.14
2009/10	45.73
2010/11	43.46
2011/12	40.38
2012/13	41.68
2013/14	45.83
2014/15	46.24

Section:	Appendix 11.19(IFF14) Appendix 11.21 Revised	**Page No.:**	MFR 1 MFR 4
Topic:	Export Revenues		
Subtopic:	Unit Export Revenues		
Issue:	Average Flow Year Unit Revenue		

PREAMBLE TO IR (IF ANY):

MH has suggested that average flow year unit export prices would be higher than historical because Manitoba Hydro would reduce low-value sales.

QUESTION:

c) Plot the recalculated average total unit export annual revenues from 2014/15 out to 2023/24 using 2% escalation and 4% escalation.

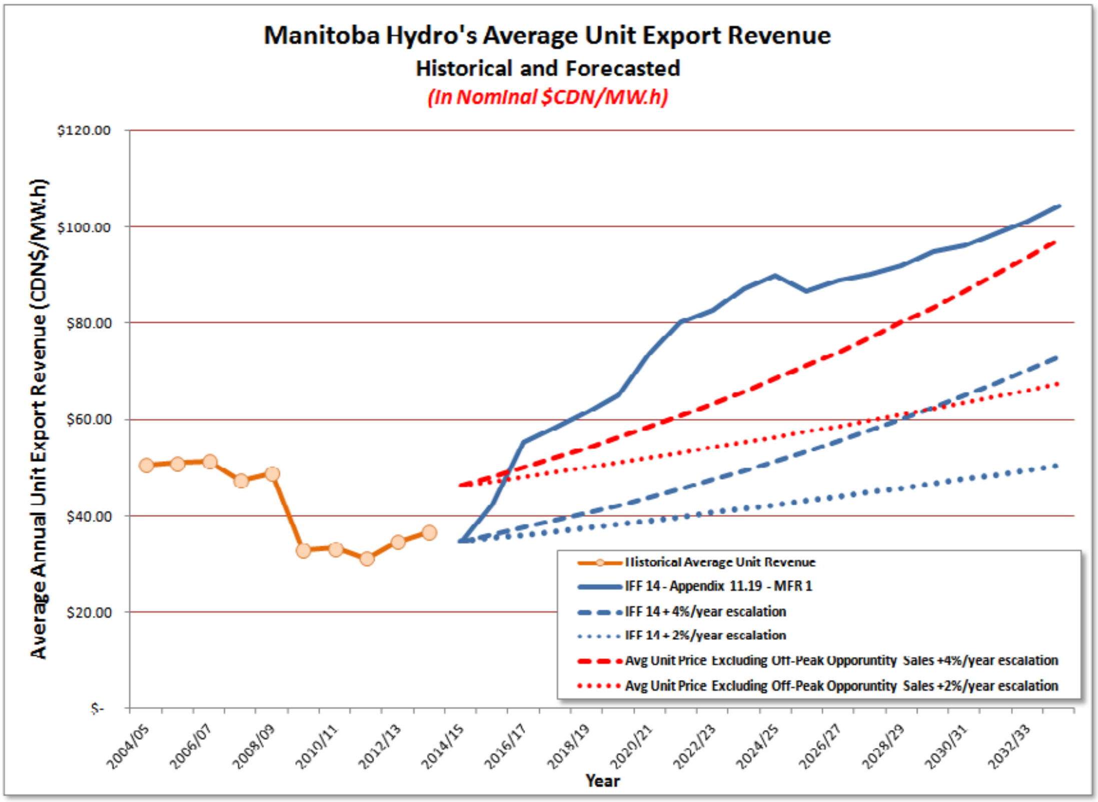
d) Plot the Appendix 11.19 total unit export revenues on the same graph as (c). Explain the natural gas price and CO_2 emission pricing implications.

RATIONALE FOR QUESTION:

To explore the impact of low-flow years on export prices.

RESPONSE:

The chart below contains the information requested in both parts c & d.



Two sets of escalated curves are provided. The IFF14 escalated curves start with an initial value of $34.67/MWh, while the Average Unit Price Excluding Off Peak Opportunity Sales starts with an initial value of $46.24/MWh in 2014/15, as provided in Manitoba Hydro's response to PUB/MH-II-87a-b. Manitoba Hydro notes that in higher flow years, such as recently experienced, there is a higher proportion of export sales that occur in the lower priced off peak period, which has the effect of reducing the overall average unit export revenue, in comparison with an average water flow year.

No natural gas price and CO2 emission pricing implications can be discerned from the 2% escalation and 4% escalation lines.

Section:	11	**Page No.:**	PUB/MH I-10b, PUB/MH I-75c, Appendix 11.19 11.38
Topic:	Minimum Filing Requirements		
Subtopic:	Finance Expense		
Issue:	Interest Rates		

PREAMBLE TO IR (IF ANY):

MH has indicated that Interest rates have declined from the levels forecast by MH in IFF14 as follows:

Fiscal Year	**Manitoba Hydro Canadian Short-term Rate**			**Manitoba Hydro Canadian Long-term Rate**		
	January 2015 Update	Application Fall 2014 Update	Basis Point Change	January 2015 Update	Application Fall 2014 Update	Basis Point Change
2014/15	1.85%	1.95%	(10)	4.20%	4.50%	(30)
2015/16	1.50%	2.30%	(80)	4.00%	5.10%	(110)
2016/17	1.95%	3.40%	(145)	4.55%	5.50%	(95)
2017/18	3.30%	4.10%	(80)	5.70%	5.80%	(10)
2018/19	3.95%	4.45%	(50)	5.75%	6.00%	(25)
2019/20 - 2033/34	4.50%	4.90%	(40)	5.75%	6.20%	(45)

Source: PUB/MH I-75c

MH has provide an alternative IFF14, in PUB/MH I-10b Appendix B based on a January 2015 update which reflects a reduction in finance expense of about $1.5 billion.

QUESTION:

a) Please provide the weighted average cost of borrowing based on the January 2015 Update and compare that with what was used in IFF14.

b) Provide an updated detail of finance expense similar to Appendix 11.38 based on the January 2015 update consistent with finance expense found in PUB/MH I-10a and PUB/MH I-10b

c) Please provide details of any new debt issues for 2014/15 and forecast for 2015/16 with the respective forecast interest rate and comment on any changes from that included in the application.

d) Please indicate the impact of the lower interest rates on the amount of capitalized interest and refile PUB/MH I-9 based on this updated view.

RATIONALE FOR QUESTION:

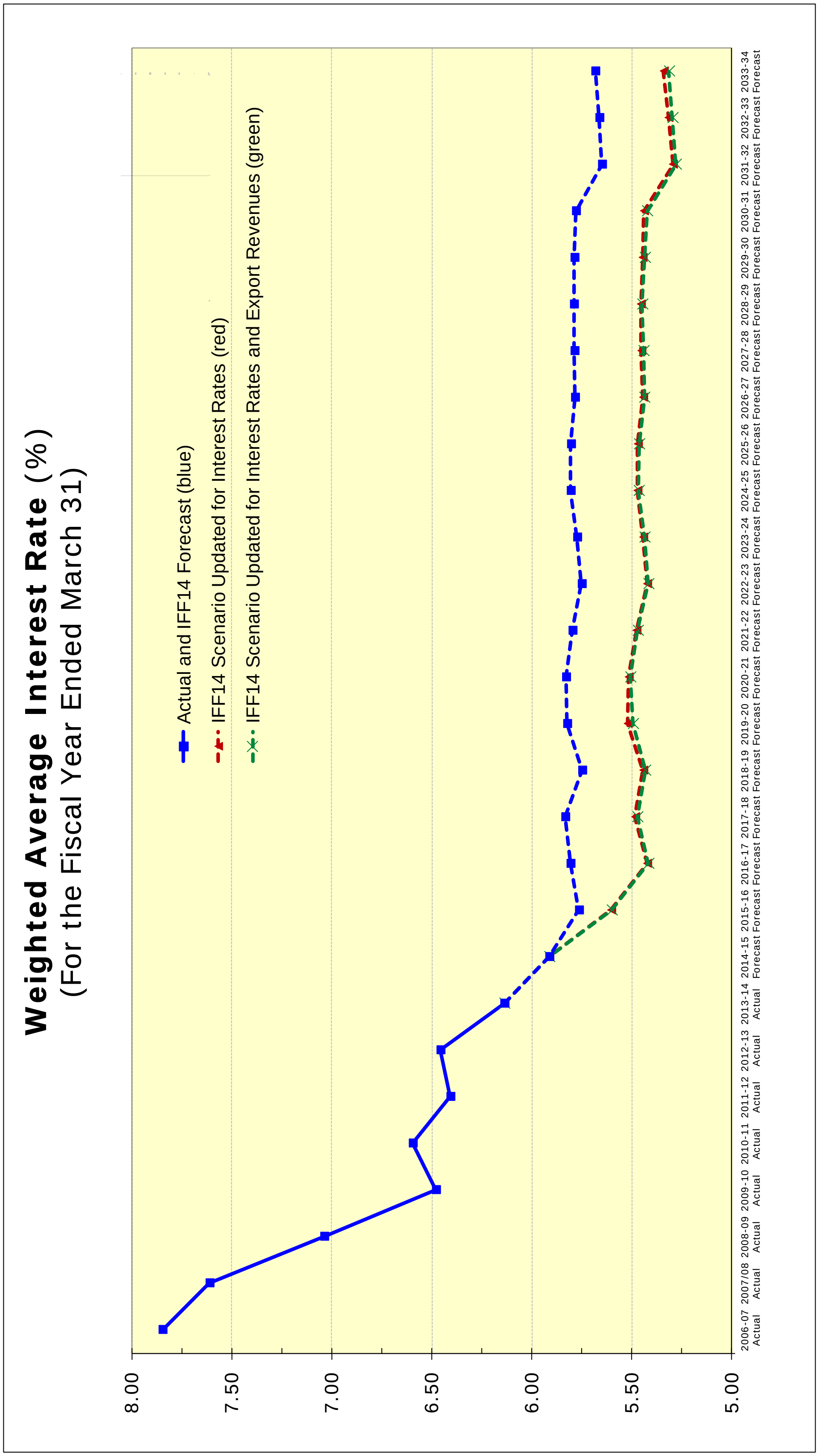
To understand the implications of changes in interest rates on MH's forecast finance expense.

RESPONSE:

Response to part a)

Please see the following chart which provides the weighted average interest rate (cost of borrowing) to 2033/34 for the IFF14 used in the Application, as well as for the IFF14 scenarios with the January 2015 updated interest rates and with the January 2015 updated interest rates and estimated export revenues (as filed in response to PUB/MH-I-10b). In order to provide comparability to IFF14, which had an October 31, 2014 cutoff date for the inclusion of actual debt issuance, the scenarios in this chart include actual long term debt issuance to October 31, 2014 and forecast issuance thereafter.

The weighted average interest rate (WAIR) declines under both scenarios by an average of approximately 30 basis points. The scenario with updated export revenues yields the lowest WAIR as the lower export revenues in this scenario lead to higher levels of borrowing which, when issued at the low interest rates, would contribute to a lower overall weighted average cost of borrowing. The decrease in the forecast interest rates, in combination with the forecast assumption of a 20 year term to maturity, shows the impact that fixing these beneficially low interest rates could have for current and future ratepayers over the 20 year timeframe.


Weighted Average Interest Rate (%)
(For the Fiscal Year Ended March 31)
Actual and IFF14 Forecast (blue)
IFF14 Scenario Updated for Interest Rates (red)
IFF14 Scenario Updated for Interest Rates and Export Revenues (green)
8.00
7.50
7.00
6.50
6.00
5.50
5.00
2006-07 Actual
2007/08 Actual
2008-09 Actual
2009-10 Actual
2010-11 Actual
2011-12 Actual
2012-13 Actual
2013-14 Actual
2014-15 Forecast
2015-16 Forecast
2016-17 Forecast
2017-18 Forecast
2018-19 Forecast
2019-20 Forecast
2020-21 Forecast
2021-22 Forecast
2022-23 Forecast
2023-24 Forecast
2024-25 Forecast
2025-26 Forecast
2026-27 Forecast
2027-28 Forecast
2028-29 Forecast
2029-30 Forecast
2030-31 Forecast
2031-32 Forecast
2032-33 Forecast
2033-34 Forecast

Response to part b)

Please see the following finance expense schedules to this information request (in a format consistent with the IFF14 finance expense information shown in Appendix 11.38):

- Attachment 1: Summary of Total Finance Expense with the IFF14 January 2015 Interest Rate Update
- Attachment 2: Summary of Total Finance Expense with the IFF14 January 2015 Interest Rate and Export Revenue Update
- Attachment 3: Total Finance Expense Variance between the IFF14 January 2015 Interest Rate Update, and IFF14
- Attachment 4: Total Finance Expense Variance between the IFF14 January 2015 Interest Rate and Export Revenue Update, and IFF14

As seen in Attachment 4, over the 20 year period there is a reduction to total net finance expense of approximately $1.5 billion due to the combination of lower forecast interest rates and export revenues. Attachment 4 also demonstrates the counterbalances which occur within finance expense. In this scenario, although gross interest and PGF decrease, there are also counterbalancing offsets arising from a reduction in the capitalized interest rate (which reduces the credited amount of interest allocated to construction) and the reduction in the interest earned rate (which reduces interest earned on sinking fund and intercompany interest receivable). See PUB/MH I-10b Attachment B for the full revenue requirement impact.

Response to part c)

Manitoba Hydro's long term debt financings secured in 2015 have taken advantage of the sharp reduction in all-in yield rates for the benefit of current and future ratepayers.

On January 14, 2015, Manitoba Hydro secured long term debt series **FR-3** for CAD $175 million and a March 5, 2041 maturity date. FR-3 was issued at a premium with proceeds of $202.2 million (net of commissions), a fixed rate coupon of 4.100%, and an all-in yield of 3.215%. The debt was issued to finance new borrowing requirements. Debt series FR-3 was issued in response to investors that had specifically requested a reopening of the Manitoba 2041 bond. At the time of issuance, with an all-in yield of 3.215% (excluding 1% PGF), FR-3 was the second lowest fixed rate long bond issue in the Corporation's 64 year history.

Further downward movements in the all-in yield rates for Manitoba bonds occurred toward the latter part of the quarter. On March 2, 2015, Manitoba Hydro secured long term debt series **GK** for CAD $300 million and a September 5, 2046 maturity date. GK was issued at a discount with proceeds of $296.8 million (net of commissions), a fixed rate coupon of 2.850%, and an all-in yield of 2.902%. The debt was issued to finance new borrowing requirements and represented the inaugural tranche of Manitoba's new 30 year benchmark bond. Debt series GK, with an all-in yield of 2.902% (excluding 1% PGF), set a new record for the lowest fixed rate long bond debt issue in the Corporation's history (surpassing both FR-3 and the previous record holder C129, which had been issued in July 2012 at 3.178%).

On April 16, 2015, Manitoba Hydro secured long term debt series **GK-2** for CAD $300 million and a September 5, 2046 maturity date. GK-2 was issued at a discount with proceeds of $297.0 million (net of commissions), a fixed rate coupon of 2.850%, and an all-in yield of 2.898%. The debt was issued to finance new borrowing requirements. Debt series GK-2, with an all-in yield of 2.898% (excluding 1% PGF), set another new record for the lowest fixed rate long bond debt issue in the Corporation's history (surpassing GK issued in March 2015).

The cash requirements in 2015/16 do not vary significantly between those previously forecast in the Application (IFF14) and in the update (PUB/MH I-10b Attachment B). The interest rates forecasted for projected 2015/16 debt issues (excluding 1% PGF) changed from 4.10% in the Application to 3.00% in the update (5.10% and 4.00% including the 1% PGF).

Manitoba Hydro monitors the financial markets on an ongoing basis and will continue to secure advantageous financings for the benefit of Manitoba Hydro's current and future ratepayers.

<u>Response to part d)</u>

The lower interest rates in the scenarios lead to a reduction in the capitalized interest rate (which reduces the credited amount of interest allocated to construction). The change in the capitalized interest is not visually apparent in the chart provided in response to PUB/MH-I-9 due to the large scale on the vertical axis of the diagram. However, Attachment 4 which is provided in part b of this response shows the forecasted dollar impact arising from the change in the amount of capitalized interest between the Application and the update scenario. For example, the largest yearly decrease in interest allocated to construction of $39 million occurs in fiscal 2018 and the cumulative decrease over the 20 year period is $180 million.

ATTACHMENT 1
MANITOBA HYDRO
Summary of Total Finance Expense IFF14 Interest Rate Update
($ millions CAD)

	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021
Interest on Short & Long Term Debt													
Gross Interest	$ 469	$ 472	$ 472	$ 490	$ 515	$ 528	$ 554	$ 602	$ 690	$ 830	$ 922	$ 996	$ 1,034
Provincial Guarantee Fee	70	72	77	82	90	96	105	118	140	167	196	211	223
Amortization of (Premiums), Discounts, and Transaction Costs	(12)	(11)	3	0	0	2	3	3	2	2	2	2	3
Intercompany Interest Receivable	(18)	(16)	(16)	(17)	(19)	(19)	(21)	(22)	(24)	(30)	(35)	(40)	(43)
Total Interest on Short & Long Term Debt	**509**	**517**	**535**	**555**	**587**	**608**	**640**	**701**	**807**	**969**	**1,084**	**1,169**	**1,218**
Interest Allocated to Construction	**(74)**	**(98)**	**(136)**	**(167)**	**(138)**	**(140)**	**(146)**	**(197)**	**(283)**	**(398)**	**(357)**	**(314)**	**(102)**
Interest Earned on Sinking Fund	(25)	(24)	(17)	(10)	(10)	(24)	(0)	(2)	(7)	(18)	(22)	(23)	(20)
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	(11)	6	1	(0)	2	(19)	(11)	(17)	(11)	(15)	(6)	(9)	(10)
Revaluation of Dual Currency Bonds	32	(31)	4	3	3	2	1	1	1	1	1	1	1
Corporate Allocation	(18)	(18)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)
Other Amortization	20	20	20	24	27	28	29	29	29	29	30	30	50
Total Finance Expense	**$ 433**	**$ 373**	**$ 388**	**$ 385**	**$ 452**	**$ 435**	**$ 495**	**$ 497**	**$ 518**	**$ 551**	**$ 712**	**$ 836**	**$ 1,119**

	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034
Interest on Short & Long Term Debt													
Gross Interest	$ 1,040	$ 1,023	$ 1,033	$ 1,038	$ 1,037	$ 1,039	$ 1,038	$ 1,035	$ 1,019	$ 997	$ 917	$ 896	$ 874
Provincial Guarantee Fee	229	227	229	231	230	230	232	231	231	230	222	222	222
Amortization of (Premiums), Discounts, and Transaction Costs	4	3	1	2	2	2	2	3	3	3	4	4	4
Intercompany Interest Receivable	(32)	(25)	(27)	(28)	(29)	(30)	(31)	(32)	(33)	(34)	(36)	(36)	(37)
Total Interest on Short & Long Term Debt	**1,241**	**1,229**	**1,236**	**1,243**	**1,241**	**1,241**	**1,241**	**1,237**	**1,219**	**1,195**	**1,107**	**1,086**	**1,063**
Interest Allocated to Construction	**(11)**	**(12)**	**(15)**	**(18)**	**(22)**	**(23)**	**(15)**	**(17)**	**(18)**	**(21)**	**(22)**	**(25)**	**(31)**
	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest Earned on Sinking Fund	(19)	(6)	(8)	(12)	(14)	(27)	(40)	(52)	(61)	(72)	(54)	(66)	(79)
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	(12)	(7)	-	-	-	-	-	-	-	-	-	-	-
Revaluation of Dual Currency Bonds	2	2	2	2	2	-	-	-	-	-	-	-	-
Corporate Allocation	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(17)	(16)	(16)	(16)	(16)
Other Amortization	47	46	44	43	42	41	40	39	38	37	36	34	33
Total Finance Expense	**$ 1,229**	**$ 1,231**	**$ 1,240**	**$ 1,239**	**$ 1,230**	**$ 1,214**	**$ 1,208**	**$ 1,188**	**$ 1,161**	**$ 1,122**	**$ 1,050**	**$ 1,012**	**$ 970**

ATTACHMENT 2
MANITOBA HYDRO
Summary of Total Finance Expense IFF14 Interest Rate and Revenue Update
($ millions CAD)

	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021
Interest on Short & Long Term Debt													
Gross Interest	$ 469	$ 472	$ 472	$ 490	$ 515	$ 528	$ 554	$ 602	$ 691	$ 833	$ 926	$ 1,001	$ 1,041
Provincial Guarantee Fee	70	72	77	82	90	96	105	118	140	167	196	212	224
Amortization of (Premiums), Discounts, and Transaction Costs	(12)	(11)	3	0	0	2	3	3	2	2	2	2	3
Intercompany Interest Receivable	(18)	(16)	(16)	(17)	(19)	(19)	(21)	(22)	(24)	(30)	(35)	(40)	(43)
Total Interest on Short & Long Term Debt	**509**	**517**	**535**	**555**	**587**	**608**	**640**	**701**	**809**	**972**	**1,089**	**1,175**	**1,226**
Interest Allocated to Construction	**(74)**	**(98)**	**(136)**	**(167)**	**(138)**	**(140)**	**(146)**	**(197)**	**(283)**	**(398)**	**(357)**	**(314)**	**(102)**
Interest Earned on Sinking Fund	(25)	(24)	(17)	(10)	(10)	(24)	(0)	(2)	(7)	(18)	(22)	(23)	(20)
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	(11)	6	1	(0)	2	(19)	(11)	(17)	(11)	(15)	(6)	(9)	(10)
Revaluation of Dual Currency Bonds	32	(31)	4	3	3	2	1	1	1	1	1	1	1
Corporate Allocation	(18)	(18)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)
Other Amortization	20	20	20	24	27	28	29	29	29	29	30	30	50
Total Finance Expense	**$ 433**	**$ 373**	**$ 388**	**$ 385**	**$ 452**	**$ 435**	**$ 495**	**$ 497**	**$ 520**	**$ 553**	**$ 716**	**$ 841**	**$ 1,127**

	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034
Interest on Short & Long Term Debt													
Gross Interest	$ 1,049	$ 1,034	$ 1,047	$ 1,053	$ 1,057	$ 1,061	$ 1,066	$ 1,066	$ 1,054	$ 1,035	$ 959	$ 942	$ 924
Provincial Guarantee Fee	230	229	231	234	234	235	236	237	237	236	228	228	228
Amortization of (Premiums), Discounts, and Transaction Costs	4	3	1	2	2	2	2	3	3	3	4	4	4
Intercompany Interest Receivable	(32)	(25)	(27)	(28)	(29)	(30)	(31)	(32)	(33)	(34)	(36)	(36)	(37)
Total Interest on Short & Long Term Debt	**1,251**	**1,241**	**1,252**	**1,261**	**1,264**	**1,268**	**1,274**	**1,274**	**1,260**	**1,240**	**1,156**	**1,138**	**1,119**
Interest Allocated to Construction	**(11)**	**(12)**	**(15)**	**(18)**	**(22)**	**(23)**	**(15)**	**(17)**	**(18)**	**(21)**	**(22)**	**(25)**	**(31)**
	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest Earned on Sinking Fund	(19)	(6)	(8)	(12)	(14)	(27)	(40)	(53)	(62)	(74)	(56)	(68)	(81)
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	(12)	(7)	-	-	-	-	-	-	-	-	-	-	-
Revaluation of Dual Currency Bonds	2	2	2	2	2	-	-	-	-	-	-	-	-
Corporate Allocation	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(17)	(16)	(16)	(16)	(16)
Other Amortization	47	46	44	43	42	41	40	39	38	37	36	34	33
Total Finance Expense	**$ 1,240**	**$ 1,244**	**$ 1,257**	**$ 1,258**	**$ 1,253**	**$ 1,240**	**$ 1,240**	**$ 1,224**	**$ 1,201**	**$ 1,166**	**$ 1,097**	**$ 1,062**	**$ 1,024**

ATTACHMENT 3
MANITOBA HYDRO
Interest Rate Update Less Original IFF14
($ millions CAD)

	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021
Interest on Short & Long Term Debt													
Gross Interest	$ -	$ -	$ -	$ -	$ -	$ -	$ 0	$ (25)	$ (66)	$ (73)	$ (73)	$ (80)	$ (86)
Provincial Guarantee Fee	-	-	-	-	-	-	(0)	-	(0)	(1)	(1)	(2)	(2)
Amortization of (Premiums), Discounts, and Transaction Costs	-	-	-	-	-	-	-	-	(0)	-	-	-	-
Intercompany Interest Receivable	-	-	-	-	-	-	0	1	3	2	2	2	3
Total Interest on Short & Long Term Debt	**-**	**-**	**-**	**-**	**-**	**-**	**0**	**(24)**	**(63)**	**(71)**	**(72)**	**(79)**	**(86)**
Interest Allocated to Construction	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**10**	**32**	**39**	**30**	**27**	**10**
Interest Earned on Sinking Fund	-	-	-	-	-	-	0	0	1	1	2	1	1
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	-	-	-	-	-	-	-	-	(0)	-	-	-	-
Revaluation of Dual Currency Bonds	-	-	-	-	-	-	-	-	-	-	-	-	-
Corporate Allocation	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Amortization	-	-	-	-	-	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Total Finance Expense	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 0**	**$ (13)**	**$ (30)**	**$ (31)**	**$ (40)**	**$ (51)**	**$ (75)**

	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034
Interest on Short & Long Term Debt													
Gross Interest	$ (96)	$ (102)	$ (108)	$ (111)	$ (117)	$ (124)	$ (129)	$ (136)	$ (142)	$ (146)	$ (150)	$ (155)	$ (158)
Provincial Guarantee Fee	(3)	(4)	(5)	(5)	(6)	(7)	(8)	(8)	(10)	(10)	(10)	(10)	(10)
Amortization of (Premiums), Discounts, and Transaction Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Intercompany Interest Receivable	1	1	1	1	1	2	2	2	2	3	3	3	3
Total Interest on Short & Long Term Debt	**(98)**	**(104)**	**(111)**	**(115)**	**(122)**	**(130)**	**(135)**	**(142)**	**(149)**	**(154)**	**(157)**	**(161)**	**(165)**
Interest Allocated to Construction	**1**	**1**	**2**	**2**	**3**	**3**	**2**	**2**	**2**	**3**	**2**	**2**	**7**
Interest Earned on Sinking Fund	1	1	1	1	2	3	5	6	8	9	8	10	12
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	-	-	-	-	-	-	-	-	-	-	-	-	-
Revaluation of Dual Currency Bonds	-	-	-	-	-	-	-	-	-	-	-	-	-
Corporate Allocation	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Finance Expense	**$ (96)**	**$ (103)**	**$ (109)**	**$ (112)**	**$ (117)**	**$ (124)**	**$ (129)**	**$ (134)**	**$ (139)**	**$ (141)**	**$ (147)**	**$ (149)**	**$ (146)**

ATTACHMENT 4
MANITOBA HYDRO
Interest Rate & Revenue Update Less Original IFF14
($ millions CAD)

	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021
Interest on Short & Long Term Debt													
Gross Interest	$ -	$ -	$ -	$ -	$ -	$ -	$ 0	$ (24)	$ (64)	$ (70)	$ (70)	$ (75)	$ (79)
Provincial Guarantee Fee	-	-	-	-	-	-	(0)	-	0	(0)	(0)	(1)	(1)
Amortization of (Premiums), Discounts, and Transaction Costs	-	-	-	-	-	-	-	-	(0)	-	-	-	-
Intercompany Interest Receivable	-	-	-	-	-	-	0	1	3	2	2	2	3
Total Interest on Short & Long Term Debt	**-**	**-**	**-**	**-**	**-**	**-**	**0**	**(23)**	**(61)**	**(68)**	**(68)**	**(73)**	**(78)**
Interest Allocated to Construction	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**10**	**32**	**39**	**30**	**27**	**10**
Interest Earned on Sinking Fund	-	-	-	-	-	-	0	0	1	1	2	1	1
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	-	-	-	-	-	-	-	-	(0)	-	-	-	-
Revaluation of Dual Currency Bonds	-	-	-	-	-	-	-	-	-	-	-	-	-
Corporate Allocation	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Finance Expense	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 0**	**$ (13)**	**$ (28)**	**$ (28)**	**$ (35)**	**$ (46)**	**$ (67)**

	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034
Interest on Short & Long Term Debt													
Gross Interest	$ (88)	$ (91)	$ (94)	$ (96)	$ (98)	$ (102)	$ (102)	$ (105)	$ (107)	$ (108)	$ (108)	$ (108)	$ (108)
Provincial Guarantee Fee	(1)	(2)	(2)	(2)	(2)	(3)	(3)	(2)	(4)	(4)	(4)	(4)	(4)
Amortization of (Premiums), Discounts, and Transaction Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Intercompany Interest Receivable	1	1	1	1	1	2	2	2	2	3	3	3	3
Total Interest on Short & Long Term Debt	**(87)**	**(92)**	**(95)**	**(96)**	**(99)**	**(103)**	**(103)**	**(105)**	**(109)**	**(109)**	**(109)**	**(109)**	**(109)**
Interest Allocated to Construction	**1**	**1**	**2**	**2**	**3**	**3**	**2**	**2**	**2**	**3**	**2**	**2**	**7**
Interest Earned on Sinking Fund	1	1	1	1	2	3	4	6	7	8	7	8	10
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	-	-	-	-	-	-	-	-	-	-	-	-	-
Revaluation of Dual Currency Bonds	-	-	-	-	-	-	-	-	-	-	-	-	-
Corporate Allocation	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Finance Expense	**$ (86)**	**$ (90)**	**$ (92)**	**$ (93)**	**$ (94)**	**$ (97)**	**$ (97)**	**$ (97)**	**$ (99)**	**$ (98)**	**$ (100)**	**$ (99)**	**$ (92)**

Section:	11	**Page No.:**	PUB/MH I-10 b Attachment B, Appendix 11.19
Topic:	Minimum Filing Requirements		
Subtopic:	Export Revenue		
Issue:	Changes in Export Revenue		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update Appendix 11.19 by adding a separate calculation sheet for the adjusted IFF14 in PUB/MH I-10b Attachment B.

RATIONALE FOR QUESTION:

To determine the impact of changes in assumptions made by Manitoba Hydro.

RESPONSE:

Appendix 11.19 has been updated for the scenario in PUB/MH-I-10b Attachment B and is provided in the schedule below.

AVERAGE UNIT REVENUE/COST CALCULATION - PUB-MH-I-10b - ATTACHMENT B Updated Interest Rates and Net Extraprovincial Revenues

VOLUMES (in GW.h)	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Demand:																				
Manitoba Domestic Energy Sales	22214	22458	22458	22881	23009	23250	23318	23458	23664	23868	24099	24336	24572	24807	25041	25325	25617	25917	26226	26546
Domestic energy Losses	3108	3224	3264	3302	2987	3013	2982	2919	2947	2976	3007	3040	3072	3107	3140	3178	3219	3260	3302	3345
Firm & Opportunity Export Sales to Canada	851	469	860	833	856	870	753	744	602	583	565	489	471	513	502	491	519	513	495	485
Firm & Opportunity Export Sales to US	9184	8174	6444	6192	6143	6289	9464	10232	10207	10017	9789	9462	9410	8960	8780	8559	8200	7870	7501	7258
Net Transmission Losses	958	887	665	632	630	648	927	991	970	949	919	884	877	840	819	793	764	727	692	664
Total Demand Volumes:	**36315**	**35212**	**33691**	**33841**	**33624**	**34071**	**37444**	**38345**	**38389**	**38394**	**38379**	**38211**	**38401**	**38227**	**38281**	**38347**	**38319**	**38287**	**38217**	**38297**
Supply:																				
MH Hydraulic Generation	35116	33998	31084	31129	30907	31456	34535	35275	35251	35253	35138	35078	35243	35141	35144	35146	35224	35125	35133	35157
MH Thermal Generation	101	117	326	349	350	298	151	142	147	140	148	148	155	122	118	120	108	107	106	108
Purchased Energy	1098	1097	2281	2363	2367	2316	2758	2927	2991	3000	3094	2984	3004	2964	3019	3082	2987	3056	2979	3031
Total Supply Volumes:	**36315**	**35212**	**33691**	**33841**	**33624**	**34071**	**37444**	**38345**	**38389**	**38393**	**38379**	**38211**	**38401**	**38227**	**38281**	**38347**	**38319**	**38287**	**38217**	**38297**

REVENUE/COST (in milions of dollars)	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Total Manitoba Domestic Energy Sales:																				
Manitoba Domestic Energy Sales @ Approved Rates	1 436.742	1 454.388	1 460.247	1 482.604	1 490.283	1 501.465	1 505.896	1 513.421	1 525.486	1 537.543	1 551.384	1 565.461	1 579.532	1 593.283	1 607.122	1 623.939	1 641.157	1 658.777	1 677.031	1 695.791
Additional Domestic Revenue	0.000	57.448	117.638	182.720	249.787	320.910	394.053	471.445	554.231	641.409	734.027	831.780	934.799	1 043.117	1 157.220	1 279.663	1 409.139	1 485.929	1 565.867	1 648.967
Manitoba Domestic Sales	**1 436.742**	**1 511.836**	**1 577.885**	**1 665.324**	**1 740.070**	**1 822.375**	**1 899.949**	**1 984.866**	**2 079.717**	**2 178.952**	**2 285.411**	**2 397.241**	**2 514.331**	**2 636.400**	**2 764.342**	**2 903.602**	**3 050.296**	**3 144.706**	**3 242.898**	**3 344.758**
Extraprovincial Revenue:																				
Total Export Sales to Canada	28.748	15.008	40.529	40.469	43.892	47.264	43.325	45.051	32.837	33.462	33.521	29.599	29.061	33.987	33.757	34.152	37.658	38.543	37.982	38.380
Total Export Sales to USA	343.003	348.543	358.905	366.699	383.233	412.381	699.051	821.326	847.233	872.827	881.088	801.649	814.338	783.421	781.274	787.060	768.886	758.904	743.039	742.918
Other Non-Energy Related Revenues	19.698	15.880	2.765	2.820	2.876	2.934	2.990	3.046	3.104	3.163	3.223	3.285	3.347	3.411	3.475	3.542	3.609	3.677	3.747	3.818
Transmission Credits	17.443	22.140	23.841	24.294	24.755	24.824	25.296	25.776	26.266	26.765	27.274	27.792	28.320	28.858	29.406	29.965	30.534	31.114	31.706	32.308
Extraprovincial Revenue	**408.892**	**401.571**	**426.040**	**434.282**	**454.757**	**487.403**	**770.661**	**895.199**	**909.441**	**936.218**	**945.106**	**862.325**	**875.067**	**849.677**	**847.913**	**854.718**	**840.687**	**832.239**	**816.473**	**817.424**
Water Rentals & Assessments:																				
MH Water Rentals	117.417	113.788	103.902	104.051	103.310	105.144	115.437	117.912	117.830	117.838	117.451	117.252	117.802	117.462	117.474	117.479	117.738	117.408	117.434	117.516
Assessments	4.934	5.683	6.165	6.329	6.499	6.567	6.742	6.923	7.108	7.300	7.496	7.696	7.903	8.115	8.334	8.558	8.789	9.026	9.269	9.521
Other Costs	2.118	2.115	2.100	2.118	2.137	2.154	2.172	2.190	6.977	7.443	7.710	7.571	7.770	7.976	8.153	8.486	8.844	9.123	9.505	9.908
Water Rentals & Assessments:	**124.469**	**121.586**	**112.167**	**112.499**	**111.946**	**113.866**	**124.351**	**127.024**	**131.915**	**132.580**	**132.657**	**132.520**	**133.475**	**133.553**	**133.960**	**134.523**	**135.372**	**135.557**	**136.208**	**136.944**
Fuel & Power Purchased:																				
MH Thermal Generation	6.179	6.004	19.875	22.437	23.634	21.194	12.914	12.716	13.672	13.493	14.642	15.258	16.653	13.745	13.878	14.658	13.923	14.300	14.763	15.729
Purchased Energy	70.910	70.620	109.945	115.710	118.118	118.587	134.432	145.826	151.280	159.194	167.133	162.858	167.600	169.608	175.288	183.441	183.549	191.352	192.656	201.860
Other Non-Energy related Costs	14.142	12.663	8.777	9.148	9.453	9.568	12.076	26.005	16.313	16.730	17.215	17.686	18.198	18.556	19.048	19.579	20.064	20.610	21.174	21.773
Transmission Charges	42.958	37.416	48.013	50.034	50.985	51.131	67.564	67.344	67.969	68.612	69.275	70.213	70.914	71.636	72.378	73.141	78.423	79.229	80.057	80.908
Fuel & Power Purchased	**134.189**	**126.702**	**186.610**	**197.329**	**202.191**	**200.480**	**226.986**	**251.891**	**249.234**	**258.030**	**268.265**	**266.014**	**273.365**	**273.544**	**280.592**	**290.818**	**295.959**	**305.492**	**308.650**	**320.269**

AVERAGE UNIT REVENUE/COST ($/MW.h))	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Manitoba Domestic Energy Sales @ Approved Rates	$ 64.68	$ 64.76	$ 65.02	$ 64.80	$ 64.77	$ 64.58	$ 64.58	$ 64.52	$ 64.47	$ 64.42	$ 64.38	$ 64.33	$ 64.28	$ 64.23	$ 64.18	$ 64.12	$ 64.07	$ 64.00	$ 63.94	$ 63.88
Additional Domestic Revenue	-	2.56	5.24	7.99	10.86	13.80	16.90	20.10	23.42	26.87	30.46	34.18	38.04	42.05	46.21	50.53	55.01	57.33	59.71	62.12
Total Manitoba Domestic Energy Sales @ meter	64.68	67.32	70.26	72.78	75.62	78.38	81.48	84.61	87.89	91.29	94.83	98.51	102.32	106.28	110.39	114.65	119.07	121.34	123.65	126.00
Total Export Sales to Canada	35.86	39.78	52.70	54.55	57.39	60.62	65.42	68.94	64.26	67.98	70.68	74.40	76.51	80.52	82.11	85.24	88.02	91.24	93.95	97.48
Total Export Sales to USA (includes Net Trans Credits)	34.57	40.77	51.94	55.06	58.12	61.39	69.40	76.21	78.92	82.95	85.72	80.24	82.01	82.66	84.09	86.91	87.93	90.31	92.61	95.67
Total Export Sales	34.67	40.73	52.02	55.01	58.04	61.30	69.14	75.77	78.22	82.25	85.02	80.01	81.80	82.57	84.00	86.83	87.93	90.36	92.68	95.76
MH Hydraulic Generation (Water Rentals)	$ 3.34	$ 3.35	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	61.39	51.37	61.03	64.31	67.54	71.04	85.53	89.55	92.72	96.07	99.18	103.09	107.44	112.66	117.70	122.43	129.03	134.10	139.75	145.03
Purchased Energy (Including Assessments)	69.06	69.55	50.90	51.65	52.65	54.03	51.18	52.18	52.95	55.50	56.44	57.15	58.43	59.95	60.82	62.30	64.39	65.57	67.79	69.73

Section:	Appendix 11.1	**Page No.:**	MFR 10
Topic:	Corporate Risk Management Report		
Subtopic:	Water Supply Variation – Drought Risk		
Issue:	Drought Cost		

PREAMBLE TO IR (IF ANY):

Page 5 of the Corporate Risk Management Plan (CRMP) indicates the cost of a 5 year drought being $1.7B (IFF14) for a drought commencing in 2017. Page 6 appears to suggest that a retained earnings level of $2.7B is sufficient.

QUESTION:

a) Does the $1.7 billion drought cost in the CRMP include finance costs? If not, please indicate the cost of a drought including finance costs.

b) In MIPUG/MH I-8, MH provided a drought cost for both a 5 year and a 7 year drought of $1.5 billion and $2.1 billion respectively (not including finance costs). Please provide the finance cost for each case.

c) Explain why the CRMP did not consider a 7 year drought in assessing the retained earnings adequacy.

d) Explain why MH did not consider IFF14's $2.0 billion retained earnings in the risk assessment.

RATIONALE FOR QUESTION:

To explore drought risk.

RESPONSE:

a) The $1.7 billion drought cost includes financing costs.

b) The total cost of the 5 year and 7 year droughts including financing costs is as follows:

Drought	Drought cost before financing	Financing Costs	Total Cost of Drought
5 years	$1.5 billion	0.2 billion	$1.7 billion
7 years	$2.1 billion	0.3 billion	$2.4 billion

c) While the potential financial impact of a seven year drought is approximately $700 million greater than the five year drought, the likelihood of occurrence is low. Given the low likelihood of occurrence, the risk of a seven year drought is within acceptable risk tolerance relative to the impact to customers of maintaining even higher levels of retained earnings and a five year drought provides a sufficient stress test to the forecast for risk planning purposes.

d) Manitoba Hydro does not agree with the assumption in the question that it did not consider the projected reduction in retained earnings to $2 billion by 2024 as part of its risk assessment. The portions of the CRM report that are quoted in the question only relate to the high consequence risk of water supply variation and drought risk outlined on pages 5 & 6 of the CRM report.

On pages 8 & 9 of the CRM report, under the section of significant and emerging risks, Manitoba Hydro has considered the risks associated with financial strength and domestic electricity rate increases, which inherently recognizes the financial outlook contained in IFF14. This section of the CRM report outlines key areas of focus in order to maintain financial strength, including continuing cost containment measures, aggressively pursuing a balanced portfolio of domestic and profitable export sales, managing and mitigating financial risks by closely monitoring economic factors, financial markets and energy markets, and implementing modest, regular domestic electricity rate increases necessary to achieve financial targets over the long term.

Section:	Tab 9	Page No.:	PUB/MH I-58
Topic:	Energy Supply		
Subtopic:	2014 Power Resource Plan		
Issue:	Capacity & Energy Surplus		

PREAMBLE TO IR (IF ANY):

MH's 2014 PRP does not include an average flow operations chart as in previous PRP(s).

QUESTION:

a) Provide an average flow operation chart for both the no new resource plan and the recommended plan.

b) Explain why the 2014 PRP did not consider an expanded import program that would utilize the greater import capacity to permit new firm exports.

c) Explain why the 2014 PRP did not consider a natural gas SCCT/CCCT scenario.

RATIONALE FOR QUESTION:

To explore whether the 2014 PRP examined other alternatives to a 'build Conawapa' scenario.

RESPONSE:

a) The No new resources table is not a "plan" as it depicts the system under existing and committed resources but does not include new resources to address energy and capacity deficits over the planning horizon. As a result, it is not possible to conduct a SPLASH analysis and determine average energies. Average energy tables for no new resources have not been previously provided. The requested table for the Recommended Plan has been provided below.

System Supply & Demand Balance (GW.h) at Generation
Under Average of all Flow Conditions

Keeyask/Conawapa/750 MW

Fiscal Year	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Power Resources																	
Hydro Generation	31 084	31 129	30 907	31 456	34 535	35 279	35 259	35 264	35 148	35 086	35 236	34 916	35 088	36 975	41 227	42 148	42 050
Bipole III Reduced Losses			324	324	352	352	352	352	352	352	352	352	352	352	352	352	352
Thermal Generation	358	384	385	328	174	167	176	168	178	170	174	145	132	191	167	166	164
New NUG Purchase	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
Wind	907	907	907	907	907	907	907	907	907	907	907	907	907	907	907	907	907
Total Power Resources	**32 446**	**32 516**	**32 620**	**33 112**	**36 065**	**36 802**	**36 792**	**36 788**	**36 681**	**36 612**	**36 765**	**36 416**	**36 576**	**38 522**	**42 749**	**43 670**	**43 570**
Demand																	
2014 Base Load Forecast	26 436	27 174	27 662	28 247	28 583	28 937	29 284	29 626	29 970	30 316	30 659	31 006	31 352	31 703	32 061	32 424	32 796
Non-Committed Construction Power	110	110	110	110	83		10	15	20	30	50	55	80	100	90	30	5
Demand Side Management	- 780	-1 056	-1 407	-1 730	-1 988	-2 183	-2 296	-2 405	-2 487	-2 562	-2 637	-2 717	-2 797	-2 825	-2 851	-2 874	-2 895
Net Load	**25 766**	**26 229**	**26 366**	**26 627**	**26 678**	**26 754**	**26 998**	**27 236**	**27 504**	**27 784**	**28 072**	**28 344**	**28 635**	**28 979**	**29 300**	**29 580**	**29 907**
Imports and Exports																	
Imports	-1 355	-1 441	-1 445	-1 392	-1 861	-2 048	-2 115	-2 119	-2 223	-2 124	-2 155	-2 208	-2 251	-1 712	-1 388	-1 633	-1 671
Exports	3 373	3 438	3 232	3 192	4 474	5 342	5 278	5 251	5 251	2 969	2 825	2 286	2 167	2 656	3 985	3 985	3 985
Net Imports/Exports	**2 018**	**1 998**	**1 788**	**1 801**	**2 614**	**3 294**	**3 163**	**3 132**	**3 028**	**845**	**670**	**78**	**- 84**	**944**	**2 597**	**2 352**	**2 314**
Total Energy Demand	**27 784**	**28 227**	**28 154**	**28 428**	**29 292**	**30 048**	**30 161**	**30 368**	**30 532**	**28 628**	**28 742**	**28 422**	**28 551**	**29 923**	**31 897**	**31 932**	**32 221**
System Surplus	**4 662**	**4 289**	**4 466**	**4 683**	**6 773**	**6 754**	**6 630**	**6 420**	**6 149**	**7 984**	**8 023**	**7 994**	**8 026**	**8 599**	**10 853**	**11 738**	**11 349**

Fiscal Year	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49	2049/50
Power Resources																	
Hydro Generation	42 046	42 094	42 076	42 097	42 112	42 097	42 503	42 616	42 680	42 669	42 671	42 680	42 672	42 666	42 659	42 678	42 675
Bipole III Reduced Losses	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352
Thermal Generation	161	160	143	97	92	93	91	93	93	95	96	97	98	99	101	102	103
New NUG Purchase	97	97															
Wind	907	907	907	907	907	907	907	907	907	907	907	907	907	907	907	907	907
Total Power Resources	**43 563**	**43 610**	**43 478**	**43 454**	**43 464**	**43 449**	**43 853**	**43 967**	**44 033**	**44 023**	**44 027**	**44 036**	**44 029**	**44 024**	**44 019**	**44 039**	**44 037**
Demand																	
2014 Base Load Forecast	33 177	33 557	33 937	34 317	34 698	35 078	35 458	35 839	36 219	36 599	36 980	37 360	37 740	38 121	38 501	38 881	39 262
Non-Committed Construction Power			4	12	16	28	8	8	4								
Demand Side Management	-2 912	-2 931	-2 951	-2 972	-2 993	-3 015	-3 037	-3 041	-3 042	-3 044	-3 046	-3 046	-3 046	-3 046	-3 046	-3 046	-3 046
Net Load	**30 264**	**30 626**	**30 991**	**31 358**	**31 721**	**32 091**	**32 430**	**32 806**	**33 181**	**33 556**	**33 934**	**34 314**	**34 695**	**35 075**	**35 455**	**35 836**	**36 216**
Imports and Exports																	
Imports	-1 697	-1 746	-1 588	-1 297	-1 281	-1 325	-1 299	-1 335	-1 361	-1 395	-1 425	-1 468	-1 499	-1 539	-1 582	-1 619	-1 665
Exports	3 985	3 985	2 642	729	398	398	398	398	145	145	145	145	145	145	145	145	145
Net Imports/Exports	**2 288**	**2 240**	**1 054**	**- 568**	**- 883**	**- 927**	**- 901**	**- 937**	**-1 216**	**-1 250**	**-1 280**	**-1 323**	**-1 354**	**-1 394**	**-1 437**	**-1 474**	**-1 520**
Total Energy Demand	**32 552**	**32 865**	**32 045**	**30 790**	**30 837**	**31 164**	**31 528**	**31 869**	**31 965**	**32 305**	**32 654**	**32 991**	**33 341**	**33 681**	**34 019**	**34 361**	**34 696**
System Surplus	**11 011**	**10 744**	**11 433**	**12 664**	**12 626**	**12 285**	**12 324**	**12 098**	**12 068**	**11 718**	**11 373**	**11 045**	**10 688**	**10 343**	**10 000**	**9 677**	**9 341**

b) The 2014 PRP includes imports over existing interconnections as well as imports over the committed US 500 kV interconnection. The quantity of imports available to serve Manitoba Hydro firm energy requirements, including export sales, are based on Manitoba Hydro's Generation Planning Criteria, as well as, consideration for uncertainty in the market availability of import energy on a firm basis. As indicated in the response to part c) of this Information Request, the scope the 2014 PRP was reduced and alternative plans were not included.

c) The scope of the 2014 PRP was to provide an update in order to support the annual corporate resource and financial planning cycles. Alternative plans were not included based on this reduced scope. Conawapa G.S. is included in the 2014/15 recommended development plan to recognize current negotiations for new export sales and to enable additional analysis of the need and timing of Conawapa G.S.